Facility: CPNPP JPM # NRC RA1 Task # RO1413M K/A # 2.1.25 3.9 / 4.2

Title: Determine Loss of RHR Time Limitations

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Unit 2 is in MODE 5 with Actual water level in the Reactor Vessel at 49" above the Core Plate.
- All Pressurizer Safety Valves have been removed.
- Reactor Coolant System temperature is 140ºF.
- The Reactor was shutdown on April 1st at 0000 after operating at 100% power for the last 550 days.
- Today is April 12th and the Unit experienced a Loss of Residual Heat Removal cooling at 1200 hours.

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- CALCULATE the following times per ABN-104, Residual Heat Removal System Malfunction, Attachment 5, Time to Saturation for Loss of All RHR with the RCS at Reduced Inventory and Attachment 19, Available Time for Containment Closure:
  - DETERMINE Time to Saturation ________
  - DETERMINE Approximate Heat Up Rate ________
  - DETERMINE Time to Core Uncovery ________
  - DETERMINE Containment Closure Times:
    - Thermal Environment Limiting ________
    - Radiological Environment Limiting ________

Task Standard: DETERMINED Time to Saturation, Approximate Heat up rate, Time to Core Uncovery, And Containment Closure Time following a Loss of Residual Heat Removal System per ABN-104.

Ref. Materials: ABN-104, Residual Heat Removal System Malfunction, Rev. 9.

Validation Time: 15 minutes Time Critical: N/A Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ____________

CLASSROOM SETUP

EXAMINER:

PROVIDE the examinee with a copy of:

- **ABN-104, Residual Heat Removal Malfunction.**
  - **Attachment 5, Time to Saturation for Loss of All RHR with the RCS at Reduced Inventory (Procedure 1).**
  - **Attachment 19, Available Time for Containment Closure (Procedure 2).**

√ - Check Mark Denotes Critical Step

START TIME:	

Perform Step: 1	Determine Time to Saturation: • Calculate Time After Shutdown.
Standard:	DETERMINED number of hours between April1st at 0000 hours and April 12th at 1200. CALCULATED Time After Shutdown = 276 hours.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 2√	Determine Time to Saturation: • Find Time to Saturation from Attachment 5, Page 1.
Standard:	REFERRED to Page 1 of Attachment 5 and PLOTTED the intersection of Time After Shutdown (276 hours) and Initial Temp (140ºF) and DETERMINED: TIME TO SATURATION = 12.0 ± 0.5 minutes.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 3√	Determine Approximate Heat Up Rate: • Find approximate heat up rate for 200 and 300 hours after shutdown and calculate/interpolate the approximate heat up rate for 276 hours, from Attachment 5, Page 1.
Standard:	REFERRED to Page 1 of Attachment 5, approximate heat up rate, and uses 200 hours after shutdown value of 6.9°F/Min and 300 hours after shutdown value of 5.8, and interpolates a value of 6.06 ± 0.25°F/min.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 4√	Determine Time To Core Uncovery: • Find Time To Core Uncovery from Attachment 5, Page 2
Standard:	REFERRED to Page 2 of Attachment 5 and PLOTTED the intersection of Time After Shutdown (11 days 12 hours or 276 hours) and Initial RCS Level (49 inches above the core plate) and DETERMINED: Time To Core Uncovery = 1.85 ± 0.1 hours.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 5√	Determine Containment Closure time: • Find Containment Closure Time from Attachment 19: • Thermal Environment Limiting Curve.
Standard:	REFERRED to Attachment 19 and PLOTTED the intersection of Time After Shutdown and Thermal Environment Limiting Curve and DETERMINED: Containment Closure Time = 68 ± 5 minutes.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 6√	Determine Containment Closure time: • Find Containment Closure Time from Attachment 19: • Radiological Environment Limiting Curve.
Standard:	REFERRED to Attachment 19 and PLOTTED the intersection of Time After Shutdown and Radiological Environment Limiting Curve and DETERMINED: Containment Closure Time = 66 ± 5 minutes.
Terminating Cue:	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

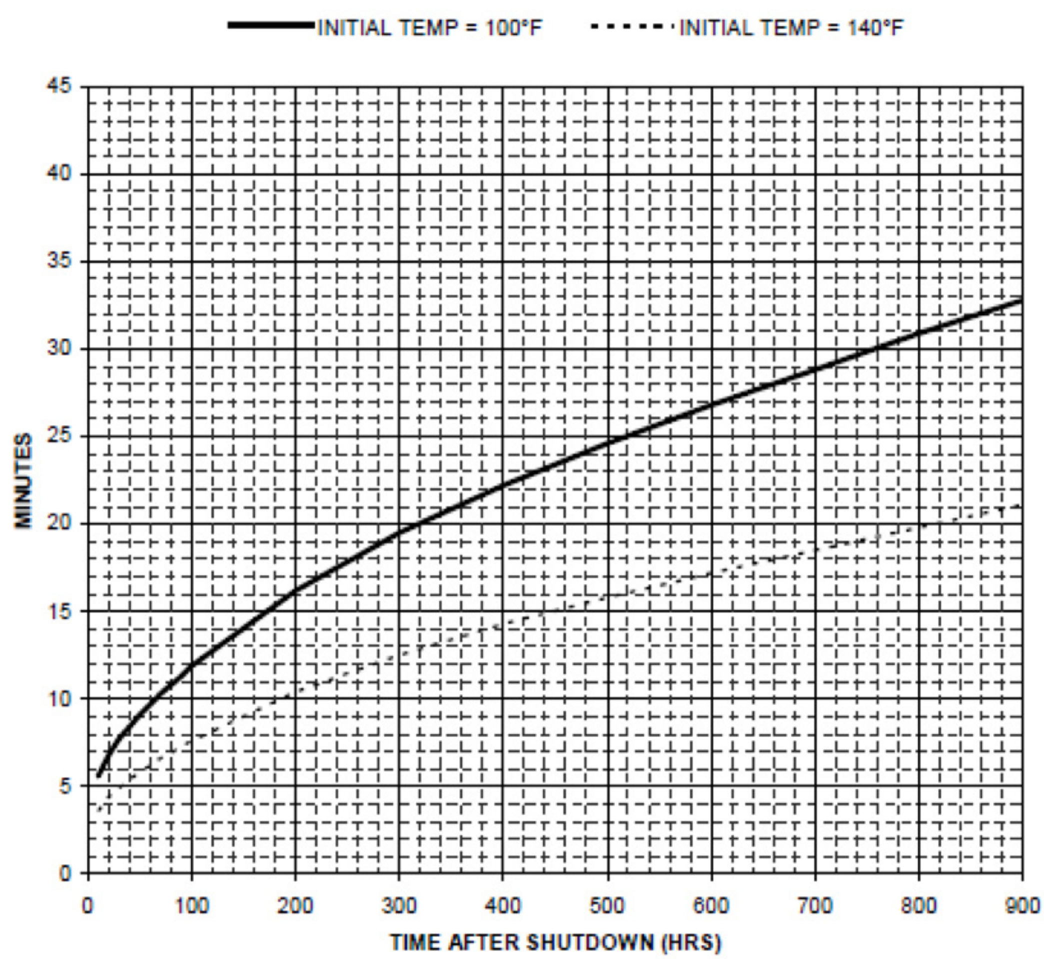
- **Unit 2 is in MODE 5 with Actual water level in the Reactor Vessel at 49" above the Core Plate.**
- **All Pressurizer Safety Valves have been removed.**
- **Reactor Coolant System temperature is 140ºF.**
- **The Reactor was shutdown on April 1st at 0000 after operating at 100% power for the last 550 days.**
- **Today is April 12th and the Unit experienced a Loss of Residual Heat Removal cooling at 1200 hours.**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **CALCULATE the following times per ABN-104, Residual Heat Removal System Malfunction, Attachment 5, Time to Saturation for Loss of All RHR with the RCS at Reduced Inventory and Attachment 19, Available Time for Containment Closure:**
  - **DETERMINE Time to Saturation** ______________
  - **DETERMINE Approximate Heat Up Rate** ______________
  - **DETERMINE Time to Core Uncovery** ______________
  - **DETERMINE Containment Closure Times:**
    - **Thermal Environment Limiting** ______________
    - **Radiological Environment Limiting** ______________

ATTACHMENT 5
PAGE 1 OF 2

[C] TIME TO SATURATION FOR LOSS OF ALL RHR WITH THE RCS AT REDUCED INVENTORY (assuming no makeup)

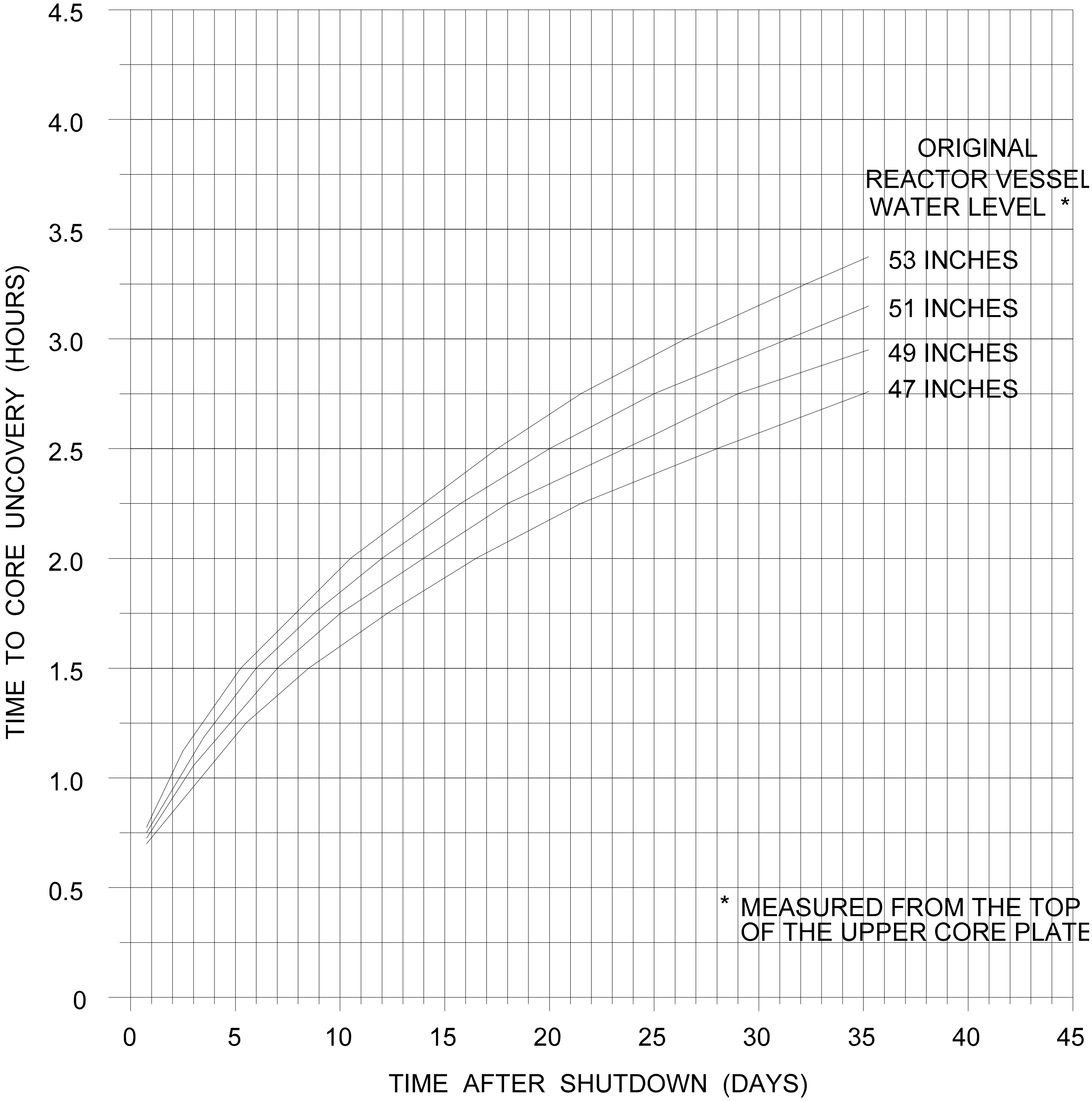


APPROXIMATE HEATUP RATE

TIME AFTER SHUTDOWN (HRS)	HEATUP RATE (°F/MIN)	TIME AFTER SHUTDOWN (HRS)	HEATUP RATE (°F/MIN)
10	19.7	100	9.5
20	16.4	200	6.9
30	14.6	300	5.8
40	13.3	400	5.1
50	12.3	500	4.6
60	11.6	600	4.2
70	10.9	700	3.9
80	10.4	800	3.7
90	9.9	900	3.5

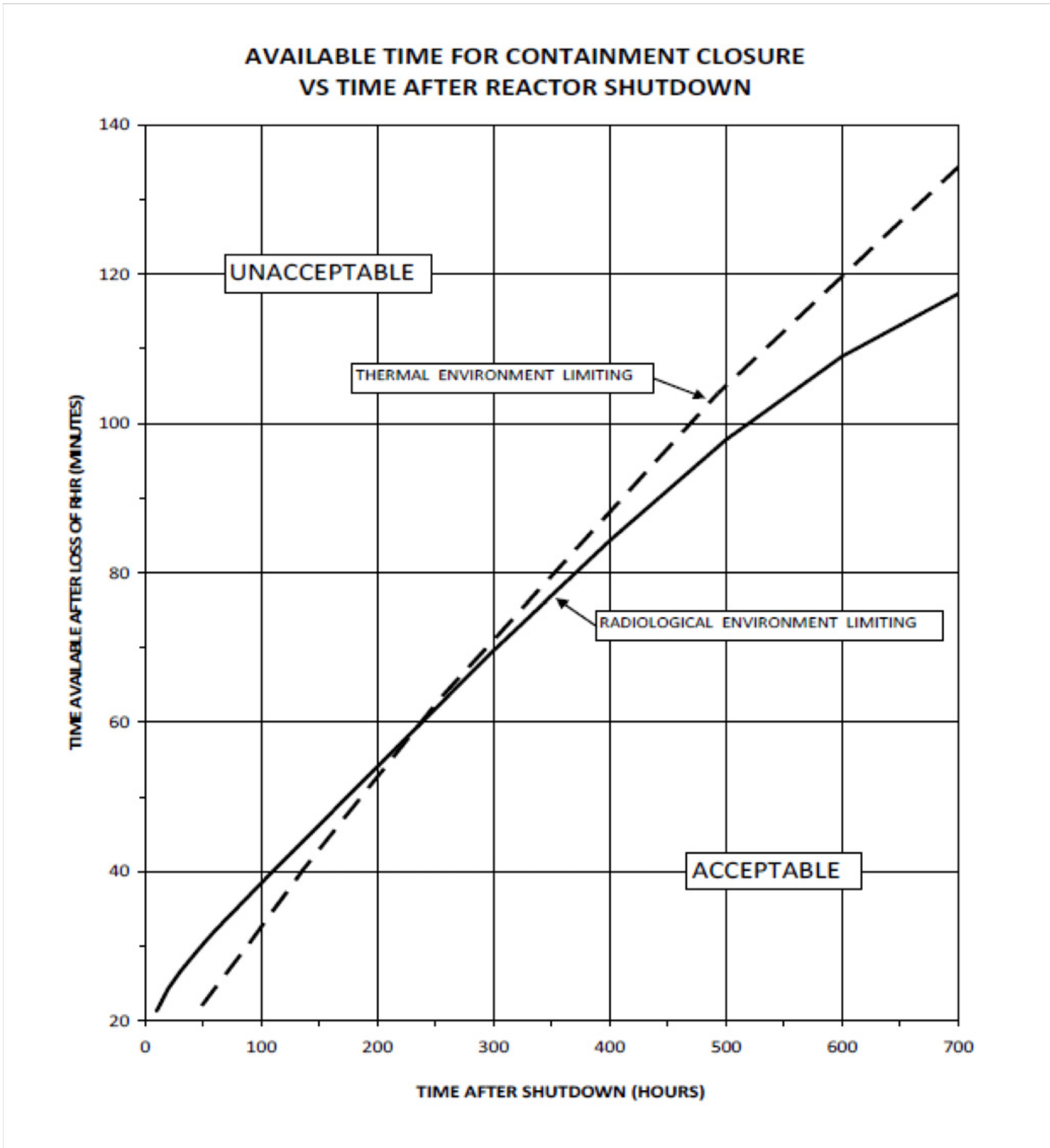
ATTACHMENT 5
PAGE 2 OF 2

TIME TO CORE UNCOVERY FOR LOSS OF ALL RHR WITH THE RCS AT REDUCED INVENTORY (assuming no makeup)



ATTACHMENT 19
PAGE 1 OF 1

[C] AVAILABLE TIME FOR CONTAINMENT CLOSURE



Initial Conditions: **Given the following conditions:**

- **Unit 2 is in MODE 5 with Actual water level in the Reactor Vessel at 49” above the Core Plate.**
- **All Pressurizer Safety Valves have been removed.**
- **Reactor Coolant System temperature is 140ºF.**
- **The Reactor was shutdown on April 1st at 0000 after operating at 100% power for the last 550 days.**
- **Today is April 12th and the Unit experienced a Loss of Residual Heat Removal cooling at 1200 hours.**

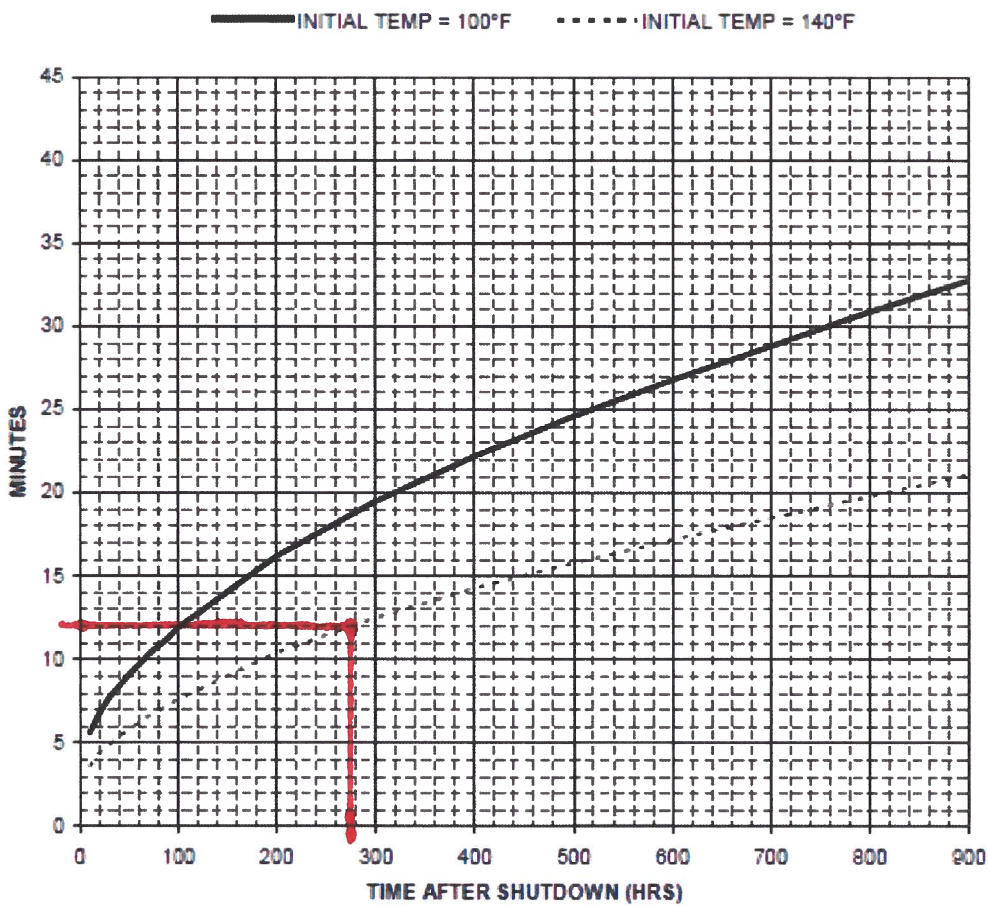
Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **CALCULATE the following times per ABN-104, Residual Heat Removal System Malfunction, Attachment 5, Time to Saturation for Loss of All RHR with the RCS at Reduced Inventory and Attachment 19, Available Time for Containment Closure:**
  - **DETERMINE Time to Saturation** 12 ± 0.5 minutes
  - **DETERMINE Approximate Heat Up Rate** 6.06 ± 0.25°F/min
  - **DETERMINE Time to Core Uncovery** 1.85 ± 0.1 hours
  - **DETERMINE Containment Closure Times:**
    - **Thermal Environment Limiting** 68 ± 5 minutes
    - **Radiological Environment Limiting** 66 ± 5 minutes

CPNPP ABNORMAL CONDITIONS PROCEDURES MANUAL	UNIT 1 AND 2	PROCEDURE NO. ABN-104
RESIDUAL HEAT REMOVAL SYSTEM MALFUNCTION	REVISION NO. 9	PAGE 74 OF 126

ATTACHMENT 5
PAGE 1 OF 2

[C] TIME TO SATURATION FOR LOSS OF ALL RHR WITH THE RCS AT REDUCED INVENTORY (assuming no makeup)



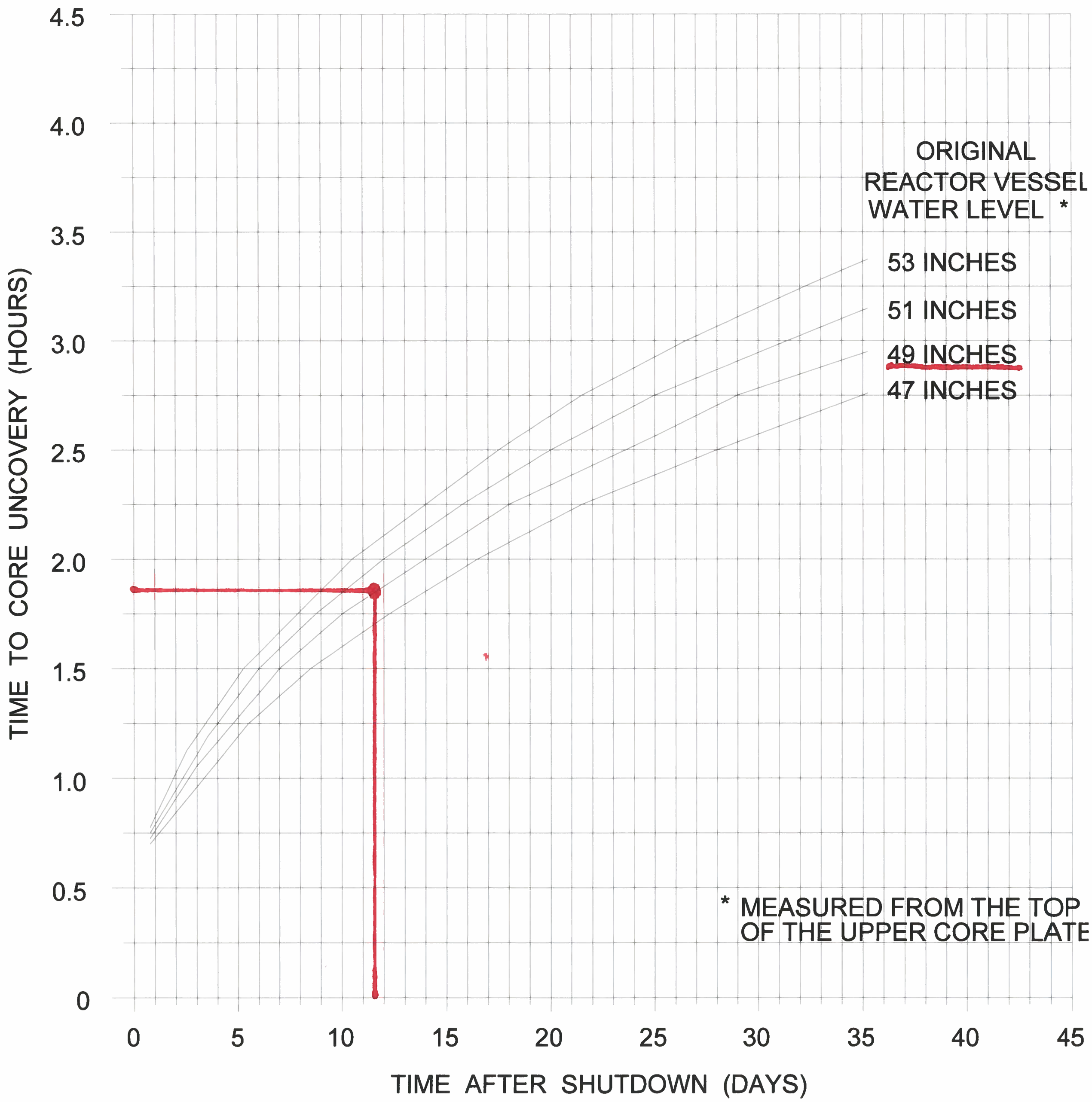
APPROXIMATE HEATUP RATE

TIME AFTER SHUTDOWN (HRS)	HEATUP RATE (°F/MIN)	TIME AFTER SHUTDOWN (HRS)	HEATUP RATE (°F/MIN)
10	19.7	100	9.5
20	16.4	200	6.9
30	14.6	300	5.8
40	13.3	400	5.1
50	12.3	500	4.6
60	11.6	600	4.2
70	10.9	700	3.9
80	10.4	800	3.7
90	9.9	900	3.5

CPNPP ABNORMAL CONDITIONS PROCEDURES MANUAL	UNIT 1 AND 2	PROCEDURE NO. ABN-104
RESIDUAL HEAT REMOVAL SYSTEM MALFUNCTION	REVISION NO. 9	PAGE 75 OF 126

ATTACHMENT 5
PAGE 2 OF 2

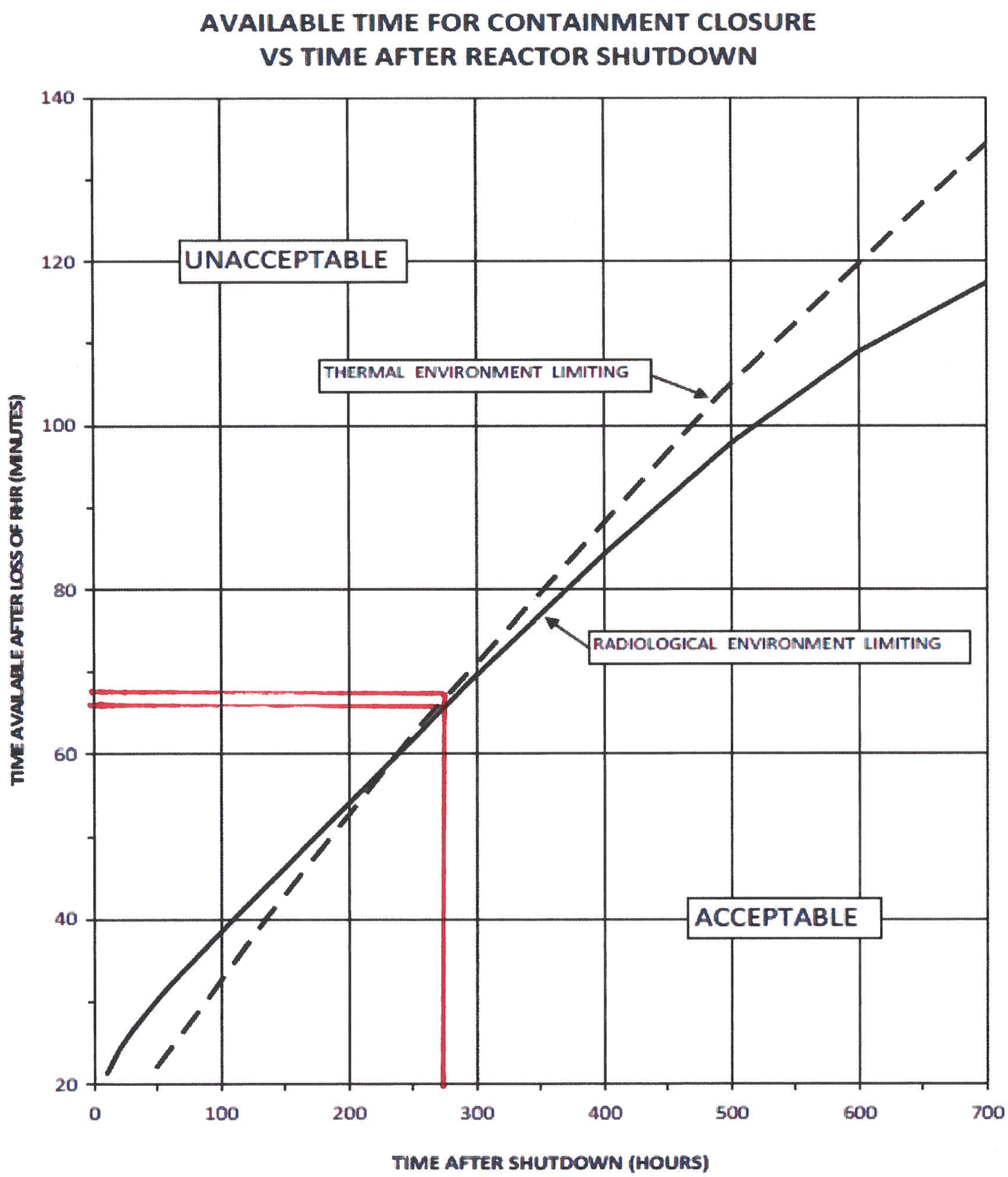
TIME TO CORE UNCOVERY FOR LOSS OF ALL RHR WITH THE RCS AT REDUCED INVENTORY (assuming no makeup)



CPNPP ABNORMAL CONDITIONS PROCEDURES MANUAL	UNIT 1 AND 2	PROCEDURE NO. ABN-104
RESIDUAL HEAT REMOVAL SYSTEM MALFUNCTION	REVISION NO. 9	PAGE 116 OF 126

ATTACHMENT 19
PAGE 1 OF 1

[C] AVAILABLE TIME FOR CONTAINMENT CLOSURE



CPNPP 2017 NRC ADMIN JPM RA1 Key

Facility: CPNPP JPM # NRC RA2 Task # BA1110 K/A # 2.1.26 3.4 / 3.6

Title: Determine Electrical Safe Work Practices Requirements

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

XCICE1, VENTILATION CHILLER X-01 COMPRESSOR MOTOR BREAKER located at 1EA1/4/BKR, is required to be racked from 'Connect' to 'Disconnect' in support of breaker tagging order.

Initiating Cue: The Shift Manager directs you to DETERMINE the following in accordance with STA-124, Electrical Safe Work Practices:

- Hazard Risk Category: ______________________________
- Minimum ATPV in cal/cm^2: ______________________________
- Flash Boundary: ______________________________
- Limited Approach Boundary: ______________________________
- Restricted Approach Boundary: ______________________________
- Arc flash suit/hood required:

  YES NO
- Ear canal hearing protection required:

  YES NO
- Insulated tools required:

  YES NO

Task Standard: Utilizing STA-124, determined the Hazard Risk Category, Minimum ATPV, Flash Boundary, Prohibited Boundary and face protection, ear canal and insulated tool requirements.

Ref. Materials: STA-124, Electrical Safe Work Practices, Rev. 3 - none

Validation Time: 15 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ____________

CLASSROOM SETUP

Handout:

PROVIDE the examinee with a copy of:

- **STA-124, Electrical Safe Work Practices. (Procedure)**

√ - Check Mark Denotes Critical Step

START TIME:	

Perform Step: 1√	DETERMINE Hazard Risk Category.
Performance Standard:	DETERMINED STA-124 Attachment 8.A, Hazard Risk Category – [4]. Attachment 8A Page 14 of 15, 6.9 KV SWGR Cabinet door closed, Hazard level column, number in parentheses is Hazard Risk Category.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2√	DETERMINE Minimum ATPV in cal/cm2 of FRC.
Performance Standard:	DETERMINED STA-124 Attachment 8A, Minimum ATPV in cal/cm2 of FRC - ≥ 50 cal/cm^2. Attachment 8A Page 14 of 15, 6.9 KV SWGR Cabinet door closed, minimum clothing column.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3√	DETERMINE Flash Boundary.
Performance Standard:	DETERMINED STA-124 Attachment 8.A, Flash Boundary – 20 ft. Attachment 8A Page 14 of 15, 6.9 KV SWGR Cabinet door closed, boundaries column.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4√	DETERMINE Limited Approach Boundary.
Performance Standard:	DETERMINED STA-124 Attachment 8.B, Approach Boundaries 5 ft 0 in. Attachment 8B, Page 1 of 1, Limited Approach Boundary column, 5.1 kV to 15 kV row.
Comment:	**SAT ☐ UNSAT ☐**
Perform Step: 5√	DETERMINE Restricted Approach Boundary.
Performance Standard:	DETERMINED STA-124 Attachment 8.B, Approach Boundaries 2 ft 2 in. Attachment 8B, Page 1 of 1, Restricted Approach Boundary column, 5.1 kV to 15 kV row.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 6√	DETERMINE Arc-rated face shield with balaclava or arc flash suit hood required.
Performance Standard:	DETERMINED that an Arc-rated face shield with balaclava or arc flash suit hood required is Required. Attachment 8A Page 13 of 13, 6.9 KV SWGR Cabinet door closed, minimum clothing column. Circled YES.
Comment:	**SAT ☐ UNSAT ☐**
Perform Step: 7√	DETERMINE Ear canal hearing protection required.
Performance Standard:	DETERMINED that Ear canal hearing protection is required Attachment 8A, Page 4 of 15, Hazard/Risk Matrix Note 11. Circled YES
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 8√	DETERMINE Insulated tools required.
Performance Standard:	DETERMINED that Insulated tools are not required. Attachment 8A, Page 14 of 15, 6.9 KV SWGR Cabinet door closed, insulated tools column. Circled NO
<u>Terminating Cue:</u>	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

XCICE1, VENTILATION CHILLER X-01 COMPRESSOR MOTOR BREAKER located at 1EA1/4/BKR, is required to be racked from 'Connect' to 'Disconnect' in support of breaker tagging order.

Initiating Cue: **The Shift Manager directs you to DETERMINE the following in accordance with STA-124, Electrical Safe Work Practices:**

- **Hazard Risk Category: ________________________________**
- **Minimum ATPV in cal/cm^2: ______________________________**
- **Flash Boundary: ______________________________________**
- **Limited Approach Boundary: ___________________________**
- **Restricted Approach Boundary: ________________________**
- **Arc flash suit/hood required:**

  YES NO

- **Ear canal hearing protection required:**

  YES NO

- **Insulated tools required:**

  YES NO

COMANCHE PEAK NUCLEAR POWER PLANT

STATION ADMINISTRATION MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____________/________ LATEST PCN/EFFECTIVE DATE NA /

LEVEL OF USE:
INFORMATION USE

ELECTRICAL SAFE WORK PRACTICES

PROCEDURE NO. STA-124

REVISION NO. 3

SORC MEETING NO: 16-019 DATE: 11-09-16

EFFECTIVE DATE: 02/15/17

MAJOR REVISION

CHANGES NOT INDICATED

PREPARED BY (Print):	BRYAN KEATHLY	EXT.	5525
TECHNICAL REVIEW BY (Print):	SCOTT HUDSON	EXT.	0117
APPROVED BY:	JOHN DREYFUSS PLANT MANAGER	DATE:	2/8/17

TABLE OF CONTENTS

1.0 PURPOSE

The purpose of this procedure is to:

1.1 Provide standards and expectations to safely work on electrical equipment and components.

1.2 Provide an awareness of the hazards to employees who might from time to time work in an environment influenced by the presence of electrical energy.

1.3 Provide consistency in electrical safe work practices.

1.4 The attachments listed below do not require SORC review when being modified and issued per STA-202:

- Attachment 8.A, “Hazard Risk Matrix”
- Attachment 8.B, “Approach Boundaries”

2.0 APPLICABILITY

2.1 This procedure is applicable to all personnel who do work associated with electrical equipment and components. This includes all resources such as contractors or support organizations.

3.0 REFERENCES

3.1 29CFR1910.269, Electric Power Generations, Transmission, and Distribution

3.2 29CFR1910.399, Subpart S, Electrical

3.3 STA-211, “Industrial Safety Program”

3.4 STA-605, “Clearance and Safety Tagging”

3.5 STA-606, “Control of Maintenance and Work Activities”

3.6 STA-617, “High Voltage Switching and Clearance”

3.7 STA-635, “Non-Plant Equipment Locking and Tagging”

3.8 STA-661, “Non-Plant Equipment Storage and Use Inside Seismic Category I Structures”

3.9 STI-124.01, “Cable Deletions and Mid Span Cuts”

3.10 MSE-CX-6000, ”Maintenance Power Installation, Removal and Rework”

3.11 MSE-CX-6001, “Maintenance Power 480 Volt Maintenance Devices Inspection and Rework”

3.12 MSE-G0-1201, “Megger Testing of Busses, MCC’s and Distribution Panels”.

3.13 MSE-G0-1209, “Hi-Pot Testing”

3.14 MSE-G0-4003, “Motor Insulation Resistance Testing”

3.15 MSE-G0-4004, “Baker On-Line Motor Testing”

3.16 MSE-G0-4201, “Megger Testing of Power Cables, Motors & Generators”

3.17 MSE-G0-4213, “Polarization Index Testing of Motors”

3.18 MSE-G0-6000, “Station Safety Grounding”

3.19 MSE-G0-6201, “Megger Testing of Transformers”

3.20 MSG-0209, “Control and Testing of Live Line Tools and Electrical Protective Equipment”

3.21 Comanche Peak Safety Handbook

3.22 Maintenance Guideline 16, “Single Person Jobs”

3.23 Maintenance Guideline 28, “480 Volt Cord Construction, Repair and Periodic Inspections”

3.24 NFPA 70E 2015 Edition, “Standards for Electrical Safety Requirements for Employee Workplaces”

3.25 SA-2003-0023, Electrical Safety Self-Assessment

3.26 ASTM F1506-08, “ Standard Performance Specification for Flame Resistant Textile Materials for Wearing Apparel for Use by Electrical Workers Exposed to Momentary Electric Arc and Related Thermal Hazards”

3.27 IER L2-12-84, “Serious Injury from Arc Flash”

3.28 IER L2-14-042, “Supplemental Workers Cut Energized High Voltage Cable”

3.29 Commitment 4924624, “IERL2-14-42, REC 2, Supplemental Workers Cut An Energized High-Voltage Cable”

3.30 OSHA 29 CFR 1910.269, “Electric Power Generation and Transmission Distribution”, April 11, 2014

3.31 CR-2015-006401, EM craft personnel experienced an Arc Flash while de-energizing transformer

4.0 DEFINITIONS/ACRONYMS

4.1 Approved Insulated Tool - A hand tool or instrument used to work on energized equipment that is clearly marked with voltage rating symbols and meets all the codes and standards. Note: An exception to the use of approved insulated tools is in the case of limited access or unavailability, then a non-insulated tool may be covered with insulating tape or Raychem with supervisor inspection and approval. This is limited to $\leq$ 120 vac/125 vdc, one time use only. Voltage rated rubber gloves must be worn when using this tool.

4.2 Arc Face Shield- Face shield designed to protect from electrical blast/flash with a minimum ATPV rating of 4 cal./cm^2 worn in combination with a hard hat.

4.3 Arc Rating - The maximum incident energy resistance demonstrated by a material prior to the onset of a second degree burn to the skin. This parameter is expressed in calories per square centimeter (cal/cm2) and is derived from the determined value of the Arc Thermal Performance Value (ATPV).

4.4 Arc Rated Clothing - Non-melting garments that are either inherently unable to catch fire or are treated with a specific treatment so that the material does not continue to burn after exposure to, and removal of, a source of ignition.

4.5 Arc Thermal Performance Value (ATPV)- The Maximum Incident Energy resistance (expressed in cal/cm2) demonstrated by a material, or layers of materials, prior to material break-open or onset of a second-degree burn.

4.6 De-Metal - The act of removing conductive articles that might present an electrical contact hazard with an exposed live part.

4.7 Electrical Protective Equipment (EPE) - Equipment that is designed to protect a worker against electrical contact. This equipment includes voltage rated rubber gloves with leather protectors, rubber insulating matting/blankets and shutter covers.

4.8 Electrically Safe Work Condition (ESWC)- A state in which the conductor or circuit part to be worked on has been isolated from the energized sources, locked out/tagged out in accordance with station procedures, live-dead-live tested to ensure absence of potential and grounded as necessary. It is an expectation that all circuits above 1000 volts should be grounded prior to working on the conductor or circuit parts.

4.9 Exposed Live Parts - Capable of being inadvertently touched or approached nearer than a safe distance by a person. It is applied to electrical conductors or circuit parts that are not suitably guarded, isolated or insulated.

4.10 Flame Resistant - The property of a material whereby combustion is prevented, terminated or inhibited following the application of a flaming or non-flaming source of ignition, with or without subsequent removal of the ignition source.

4.11 Flame Resistant Clothing (FRC) – Is clothing for purposes of this procedure that meets the definition of Flame Resistant.

4.12 Flash Hazard- A dangerous condition associated with the release of energy caused by an electric arc.

4.13 Flash Protection Boundary - Boundary established at a distance from an exposed live part within which a person could receive a second degree burn if an electrical arc flash were to occur. FPE is required for entrance past this boundary.

4.14 Flash Protection Equipment (FPE) – Equipment or clothing designed to protect workers from an arc flash while working within the flash protection boundary.

4.15 Flash Suit – A complete FRC and equipment system that covers the entire body, except for the hands and feet. This includes pants, jacket and hood fitted with a face shield.

4.16 Fresh Air Blower – A battery operated forced air system worn in conjunction with flash hoods to prevent oxygen deficient atmospheres. The system is required when performing a task for two minutes or greater.

4.17 FR Rated OREX - Clothing manufactured by OREX for use in contaminated areas when working on equipment requiring HCR 2 or less. This clothing is rated HCR 2 at 9.2 cal/cm^2 and meets the requirements of ISO 11611-2007.

4.18 Grounds/Grounding (Effectively) – Intentionally connected to earth through a ground connection or connections of sufficiently low impedance and having sufficient current carrying capacity to prevent the buildup of voltage that may result in undue hazards to connected equipment or to persons.

4.19 Guarded - Covered, shielded, fenced, enclosed or otherwise protected by means of suitable covers, casings, barriers, rails, screens, mats or platforms to remove the likelihood of approach or contact by persons or objects to a point of danger.

4.20 Insulated – Separated from other conducting surfaces by a dielectric (including air space) offering a high resistance to the passage of current.

4.21 Limited Approach Boundary - A shock protection boundary at a distance from an exposed live part that defines the approach limit for an unqualified electrical worker. Entry past this boundary requires specific skills, knowledge, or qualifications or requires escort by a qualified electrical worker.

4.22 Live Line Tool –Tools such as a hot stick, shot gun stick, disconnect stick, detex, rescue hook, etc., which are designed and used to work on energized high voltage equipment.

4.23 Live Line Tool and EPE Coordinator – Electrical Supervisor or his designee assigned the responsibility of tracking and testing live line tools and electrical protective equipment (EPE).

4.24 Observer Safety Person – A qualified person in first aid and CPR and whose only responsibility is to observe the electrical work and warn workers of near contact with an exposed live part. The observer safety person should not be involved in the associated work (except as specifically allowed on Attachment 8A Tables). An observer safety person is required (instead of the "Two Man Rule") when working on equipment rated greater than 1000 volts (e.g., Live-Dead-Live verification on 6.9 Kv switch).

4.25 Personal Protective Equipment (PPE) – Equipment designed to be worn or used by a person to provide protection from specific hazards. For purposes of this procedure PPE should include hearing protection, safety shoes, safety glasses and hard hat.

4.26 "Qualified (Electrical) Worker" (as defined in NFPA 70E) - A person who has the skills and knowledge related to the construction and operation of the electrical equipment and installations and has received safety training to recognize and avoid the hazards involved.

4.27 Rescue Equipment- Equipment designed for the sole intent of removal of a person from an exposed live part. This may include but is not limited to a insulated rescue hook.

4.28 Restricted Approach Boundary – An approach limit at a distance from an exposed live part within which there is an increased risk of shock, due to electrical arc over combined with inadvertent movement, for personnel working in close proximity to the exposed live part.

4.29 Shock Hazard - A dangerous condition associated with the possible release of energy caused by contact or approach to exposed live parts.

4.30 Standard OREX - Clothing manufactured by OREX that melts when exposed to flame. Therefore, it cannot be worn when working on exposed live parts equal to or greater than 50 VAC/VDC.

4.31 Switching - Operation of a device designed to close and/or open one or more electrical circuits, such as, breakers, cutouts, disconnects, isolating devices, or interrupter switches.

4.32 Two Man Rule – Any task that requires working on an exposed live part equal to or greater than 50 vac/vdc but less than 1000 volts ac/dc will be assigned two qualified workers, both workers can be involved in the work, each worker is responsible to watch the movement of the other to warn of near contact with an exposed live part. (When working on exposed live parts 1000V or greater, this task is performed by a dedicated Observer Safety Person.)

4.33 “Unqualified Person” (per NFPA 70E) – A person who does not possess the knowledge and skill as described in “Qualified Person”, who must maintain the proper approach boundaries from any exposed live part. An unqualified person cannot cross the limited approach boundary unless under the direction of a qualified person. Under no circumstance shall the escorted unqualified person(s) be permitted to cross the approach boundary.

4.34 Voltage Detection Equipment – A voltmeter, detex, or similar equipment capable of measuring or detecting voltage.

4.35 Voltage Nominal – A nominal value assigned to a circuit or system for the purpose of conveniently designating its voltage class. The actual voltage at which a circuit operates can vary from the nominal within a range that permits satisfactory operation of equipment. For purposes of this procedure all voltages are nominal.

4.36 Working On (Live Parts) - Intentionally coming in contact with an exposed live part with the hands, feet or other body parts, with tools, probes or with test equipment, regardless of the personal protective equipment a person is wearing. There are two categories of “working on”:

- Diagnostic (testing) is taking readings or measurements of electrical equipment with approved test equipment that does not require making any physical change to the equipment

- Repair is any physical alteration of electrical equipment (such as making or tightening connections, removing or replacing components, etc.)

5.0 RESPONSIBILITIES

5.1 Director, Maintenance

5.1.1 Responsible for maintaining this procedure current.

5.1.2 The Electrical Safety Program shall be audited to verify the principles and procedures of the program are in compliance with NFPA 70E. The frequency of the audit with a self-assessment shall not exceed three (3) years.

5.2 Work Group Supervisors

5.2.1 Monitor the electrical safe work practices of personnel under their direction.

5.2.2 Ensure only qualified personnel are assigned to perform work on an exposed live part.

5.2.3 Ensure that adequate PPE, EPE, FRC, FPE and tools are provided.

5.2.4 Observing work associated with equipment rated greater than 1000 volts.

5.2.5 Ensure adequate number of workers are assigned to task when two man rule or observer safety person are required.

5.3 All Employees

5.3.1 Use their knowledge, skills and experience to perform their jobs safely.

5.3.2 Comply with these electrical safe work practices and any associated procedures or policies.

5.3.3 Responsible for wearing the proper PPE, EPE, FRC and FPE.

5.3.4 Responsible for ensuring others working in the area comply with these requirements.

5.3.5 Stop work when discrepancies are identified and contact supervision.

6.0 INSTRUCTIONS

6.1 General Safe Work Practices

> CAUTION: It is an expectation at Comanche Peak to work on electrical equipment or components only when in an electrically safe work condition. There are times when equipment or components cannot be in a electrically safe work condition. It is at these times when additional requirements and protective measures must be applied:
>
> - Management Authorization to work on energized equipment is required
> - The level of authorization should be consistent with the potential danger to which workers are exposed

6.1.1 When working on an exposed live part with voltage equal to or greater than 50 vac/vdc the following requirements apply:

A. Obtain management approval as described in Attachment 8A, “Table of Approval Requirements”, to work on exposed energized conductors.

B. Energized work is typically associated with testing or troubleshooting of equipment.

> NOTE: Demonstration of proficiency is having completed EM11.GEL.YI6 or equivalent courses.

[C] C. Workers are qualified for the task/tasks being performed. This includes demonstrating proficiency on applicable test equipment. [4574224, 4924624]

D. Approach boundaries can be maintained.

E Workers are wearing appropriate PPE, FRC/FPE.

F. Workers should insulate/isolate themselves from an exposed live part if incidental contact is possible.

G. Approved insulated tools should be used. Exception to the use of approved insulated tools is defined in step 4.1.

H. The two man rule is in effect for tasks below 1000 volts. Above 1000V, an Observer Safety Person is used instead.

I. Due to calculated Arc Flash Hazard Energy Levels, some breakers require additional FPE and extended Arc Flash boundaries. These breakers have Arc Flash Warning Labels installed. Refer to these labels for additional requirements.

6.1.2 Ensure clearance is adequate to perform your job safely in accordance with procedures STA-605 “Clearance and Safety Tagging” and STA-635 “Non-Plant Clearance Locking and Tagging.” This includes walking down the applicable clearance tags.

6.1.3 An exposed live part is considered energized until verified de-energized using the live-dead-live method. In addition, it is an expectation that all equipment rated 1000 volts or greater be grounded prior to being considered as in an “Electrically Safe Work Condition.”

[C] 6.1.3.1 Live-Dead-Live Method [4574224, 4924624]

<u>NOTE</u>: All the following steps must be performed in sequence without turning off the voltage detection equipment.

<u>CAUTION:</u> OE 19255 identifies situations where invalid “dead” results can be obtained if a DVM with a defective scale is used in the auto range mode. Therefore, always ensure that the DVM is NOT in the auto range mode AND is set to the range corresponding to the voltage of the device that is being verified as “dead”.

<u>CAUTION</u>: Proximity testers are ineffective when utilized on shielded cable.

A. Verify that the voltage detection equipment is functional by testing on a known energized source or approved test device. A battery may be used as a source to verify the meter is functioning for DC.

B. Check the exposed live part to be worked on for absence of potential.

6.1.3.1 C. Re-verify that the voltage detection equipment is still functional by testing on a known energized source or approved test device.

6.1.4 De-Metalling is an activity intended to minimize potential for electric shock and/or equipment damage (through electrical short circuits) prior to entering (i.e., breaking the plane) a cabinet, panel, control board, or switchgear/MCC cubicle where exposed live parts are present.

6.1.4.1 De-Metalling is accomplished by removing conductive objects such as watches, rings, chains, keyrings, pens/pencils with metal pieces, and unrestrained lanyards.

- Metal safety glasses must be restrained with a “croakie.”
- Lanyards (including security badge and other devices) may be restrained by clipping directly to one’s shirt or restrained by tucking into one’s shirt. As long as the lanyard is restrained, then the small metal clips are not a concern. No other metal objects should be attached to a lanyard.
- De-Metalling is not required when entering an enclosure through a hinged door for sole purposes of operation of the equipment located inside (e.g., SSPS switches, checking 7300 system card status, reading sequence of events recorder, printouts and etc.).
- No belt buckles made of metal are to be worn whenever de-metalling is required.
- No pocket knives exposed whenever de-metalling is required.
- No keys left on lanyards when de-metalling is required.

6.1.5 When connecting or disconnecting equipment or conductors, ensure loose conductors are kept away from other exposed live parts or ground as appropriate.

- Prior to release AND prior to disconnecting any additional conductors, each individual conductor disconnected should be taped OR covered with proper sized insulating FME cap. The Electrical Supervisor may authorize not taping leads or covering with an FME cap if the entire enclosure is in an ESWC.

6.1.6 When covers, doors or guards are removed from energized equipment, if left unattended, surround the hazard area using red and black danger barricade tape placed approximately waist high and attach white information tag(s) with the responsible person's name, department, description of hazard and date of installation. Information tag (s) should be placed mid-way on each side of the barricade or at all access points to the barricaded area, as applicable.

6.1.6.1 IF an adequate area around the unattended open electrical panel or equipment CANNOT be barricaded, THEN a suitable non-conductive protective barrier should be placed in a position to preclude personnel or material contact from occurring. Such materials may include, but are not limited to, rubber, glastic, 7.5 KV insulating roll, OR treated wood. Care should be taken to ensure adequate cooling air flow to the equipment is NOT inhibited by the placed barrier.

6.1.6.2 Barriers placed around open electrical panels that must be left unattended should provide sufficient isolation distance from the equipment to prevent contact from personnel and from carried materials that inadvertently intrude into the area and must be placed no closer than the limited protection boundary distance. See Attachment 8.B.

6.1.6.3 Free standing barriers should be secured, in accordance with STA-661.

6.1.7 Ensure all covers, doors and guards are installed and properly secured (replace any missing or damaged hardware) at the completion of work activities.

6.2 Observer Safety Person

6.2.1 A worker who is currently qualified in first aid and CPR and whose only responsibility is to observe the electrical work and warn workers of near contact with an exposed live part. The observer safety person should not be distracted from his duties.

6.2.2 An observer safety person is required when working on an exposed live part with a nominal voltage rating of greater than 1000 volts. (e.g., Live-Dead-Live verification on 6.9 Kv switchgear).

Additional responsibilities are:

- Present prior to the start of the job,
- Ensure rescue equipment is available,
- Don appropriate PPE and FPE to facilitate rescue,
- Give worker being observed your complete attention,
- Initiate emergency notification and life saving actions.
- When working in remote locations outside the normal response time of the first responders, the assigned observer safety person should ensure that appropriate rescue equipment and de-fibrillator are available prior to work beginning.
- The observer safety person should ensure that a method of communicating with the control room or county emergency services is available and working.

6.3 120 Volt Rated Cords and Tools

6.3.1 Cords rated at 120 volts should be inspected in accordance with CPNPP Safety Handbook section 4.3.7 “Electrically Operated Tools and Extension Cords”.

6.4 480 Volt Rated Cords and Equipment

6.4.1 Cords rated at 480 volts are tested in accordance with Maintenance Guideline 28, “480 Volt Cord Construction, Repair and Periodic Inspections”

6.4.2 Maintenance devices rated at 480 volts are tested in accordance with and MSE-CX-6001, “Maintenance Power 480 Volt Maintenance Devices and Rework”.

6.4.3 Temporary power equipment should be installed in accordance with MSE-CX-6000, ”Maintenance Power Installation, Removal and Rework”.

6.4.4 Portable 480 volt equipment should be switched off before plugging or unplugging it from extension cords, receptacles or disconnects.

6.4.5 If a wall mounted receptacle is equipped with a disconnect, open it prior to plugging or unplugging equipment or cords. If not equipped, one of the following precautions should be taken.

- Isolate the feeder breaker to the respective receptacle in accordance with STA-605, “Clearance and Protective Tagging” and STA-635, “Non-Plant Equipment Locking and Tagging”

- The equipment or cord may be connected or disconnected by a Qualified person wearing appropriate PPE, FPE and EPE (See Attachment 8A Tables).

6.4.6 Receptacles that are designed to break the load when connecting or disconnecting are **not** acceptable means to ensure employee safety.

6.5 Batteries

NOTE:	Do not smoke or create sparks, arcs or flames in battery areas. If a device is used that produces significant heat or a spark, atmospheric monitoring should be done during the work activity to ensure an explosive atmosphere does not develop.

NOTE:	Employees shall not enter spaces containing batteries unless illumination is provided that enables the employees to perform the work safely.

6.5.1 Wear appropriate PPE, EPE and chemical protection as follows:

- Rubber latex type gloves when working with acid/lead,
- Chemical apron when working with acid,
- Hard hat with chemical face shield when working with acid/lead,
- Safety glasses,
- Safety shoes,
- Use approved insulated tools or insulating sleeves over non-insulated tools.
- Spill kits available when working with acid

6.5.2 De-metal prior to working on an exposed live part. (Reference section 6.1.4)

6.5.3 Before performing battery-related tasks, verify availability and functionality of an eye-wash station.

6.5.4 Verify that ventilation in the battery room is in service or other ventilation is present. If ventilation is not available, then continuous air monitoring is required.

6.6 Grounding

6.6.1 Installation and removal of grounds or ground devices are in accordance with MSE-G0-6000, “Station Safety Grounding”.

6.6.2 Temporary buildings, trailers or skid mounted movable maintenance equipment should be grounded prior to use or occupancy.

6.6.3 Employees are not to open or disconnect a ground or neutral on any energized equipment.

6.6.4 Ensure all grounds are connected prior to placing equipment in service after maintenance.

6.7 Live Line Tools and Electrical Protective Equipment

6.7.1 Control and testing of live line tools and electrical protective equipment are in accordance with MSG- 0209, “Control and Testing of Live Line Tools And Electrical Protective Equipment”.

6.7.1.1 Rubber/Vinyl Insulating Matting/ Blankets

- Rubber blankets should be inspected for cracks, holes, snags, blisters or any other defect immediately prior to each use. Any defective blanket should be returned to the live line tool and EPE coordinator for destruction.

- Rubber blankets should be verified to have been factory tested within the past twelve (12) months prior to use.

- The 7.5 Kv roll of Vinyl insulating matting is factory tested and considered one time use. Any portion used from the roll must retain the test stamp.

6.7.2 Live line tools and electrical protective equipment should be handled with care to prevent damage.

6.7.3 Approved insulated tools and instruments should be inspected prior to use. If damaged or not functional, remove it from service.

6.7.4 Live line tools should be wiped clean with a disposable cleaning cloth (TSN 431985) and visually inspected prior to use. Small abrasives or nicks are acceptable. Remove any defective tool from service.

- Live-line tools should be verified to have been factory tested within the past twenty four (24) months prior to use.

6.7.5 <u>Gloves</u>

6.7.5.1 Voltage rated rubber gloves are tested every six (6) months and issued in accordance with MSG-0209, “Control and Testing of Live Line Tools And Electrical Protective Equipment”. Gloves should be treated as matched pairs according to the unique identification number, issued and used as such.

6.7.5.2 Gloves should be inspected immediately prior to each use. Inspect the entire glove surface for mechanical defects such as scratches, cracked rubber, snags, blisters or any foreign material. Return any out of date or defective gloves to the live line tool and EPE coordinator for retest or destruction.

6.7.5.3 Voltage rated rubber gloves should be air tested prior to each use. This can be accomplished by either,

- rolling the cuff tightly toward the palm to trap air inside the glove and checking for punctures by either listening for escaping air or holding the glove against one’s cheek to feel for escaping air, or

- using an air inflation device.

6.7.5.4 Gloves should be stored open end down in glove bags or other approved containers in their natural shape (i.e., not folded or bent). Do not store in heat or direct sunlight. Gloves should be washed frequently with mild soap and water.

6.7.5.5 Leather glove protectors should be inspected for cuts, tears, contamination from oils or other liquid and any other damage that would degrade the glove’s integrity. Remove from service any defective leather protector.

6.7.5.6 Leather glove protectors should be worn over voltage rated rubber gloves at all times.

6.7.5.7 When selecting voltage rated rubber gloves and leather protectors, ensure that the cuff of the voltage rated rubber glove extends beyond the leather protectors by the following lengths.

Class	Working Voltage	Protector Length
00	0 to 500	1/2 inch
0	0 to 1000	1 inch
2	600 to 17 Kv	2 inches
3	17 Kv to 26.5 Kv	3 inches

6.7.5.8 Voltage rated rubber gloves with leather protectors are required when specified in **Attachment 8A.**

6.8 Test Areas and Test Equipment

6.8.1 Ensure test equipment is properly grounded. Unless ground isolation of the test equipment is specified in the testing procedure or work instructions, ensure all test equipment barriers/guards are in place, and equipment is in good working order.

6.8.2 Ensure all test conductors and equipment are securely restrained and routed to avoid damage or accidental interruption.

6.8.3 PPE, FPE, FRC and EPE requirements should be met.

6.8.4 Ensure that the area is free of clutter and is generally in a safe condition.

6.8.5 The worker conducting the testing should ensure that unauthorized personnel and carried materials cannot come into contact with any energized test equipment or exposed live part. Place barricades/barriers as needed in accordance with step 6.1.6.

6.8.6 Do not leave a test area unattended while tests are in progress.

Exceptions must be approved by supervision and barricades/barriers/information tags should be placed in accordance with step 6.1.6.

6.8.7 Do not exceed design voltages of equipment under test. Ensure proper range and function are selected prior to use.

6.8.8 Megger and hi-potential testing should be in accordance with the following:

- MSE-G0-1201, “Megger Testing of Busses, MCC’s and Distribution Panels”.
- MSE-G0-1209, “Hi-Pot Testing”
- MSE-G0-4201, “Megger Testing of Power Cables, Motors & Generators”
- MSE-G0-4213, “Polarization Index Testing of Motors”
- MSE-G0-6201, “Megger Testing of Transformers”
- MSE-G0-4003, “Motor Insulation Resistance Testing”

6.8.9 Shop Testing of Equipment - When Megger or High-Potential testing equipment that has been removed from service and are free-standing (e.g., breakers and de-terminated motors), PPE and EPE are required.

6.9 <u>6.9 kV Switchgear</u>

6.9.1 During outages some cubicles remain energized within the switchgear. Therefore, access to the cubicles should be barricaded and posted with a “Danger Equipment Energized do not enter without supervisor present” or similar sign.

6.9.2 Prior to installing breakers in cubicle do a close out inspection for any foreign material. Close door and secure all hardware.

6.10 Shutter Covers and Shutter Tools

6.10.1 Installation and removal of half or full shutter covers requires protective equipment and apparel as specified in **Attachment 8A**.

6.10.2 Shutter covers should be installed anytime the breaker is removed and the need arises to enter the cubicle of any energized 6.9 Kv switchgear.

- Shutter covers are not required for work above the breaker cubicle in the auxiliary compartment or on the cubicle door as long as the worker does not enter the lower cubicle.

6.10.3 Shutter tools should be used anytime manipulation of the shutter is required.

- Shutter tools are not required on switch gears which are in an electrically safe work condition (ESWC).

6.11 Boundaries

6.11.1 When boundaries are required to support work on exposed live parts, alert others in the vicinity of the hazards associated with the work. This can be accomplished by the following:

- Place barricades/barriers in accordance with step 6.1.6.

- Post an attendant to warn and protect other workers ($\geq$ 480V only)

6.11.2 The following boundaries should be maintained when working on exposed energized equipment. Reference **Attachment 8B.**

- Flash Protection Boundary - An approach limit at a distance from an exposed live part within which a person could receive a second degree burn if an electrical arc flash were to occur.

- Limited Approach Boundary – An approach limit at a distance from an exposed live part within which a shock hazard exists. A non-qualified person cannot cross the limited approach unless under the direction of a qualified person.

- Restricted Approach Boundary - A shock protection perimeter that can only be crossed by qualified persons knowledgeable in the use of shock protection techniques, tools, and equipment (previously known as Minimum Approach Boundary).

6.12 Current Transformers

Caution :	Opening the secondary circuit of an energized current transformer can result in a serious flash hazard.

6.12.1 If the primary of the current transformer cannot be de-energized before work is performed on a device in the secondary circuit, the circuit should be bridged (shorted) so that the current transformer secondary cannot be opened. (Contact Meter And Relay Supervisor for assistance)

6.13 Street Lighting

6.13.1 Street lighting should be de-energized prior to any hands on work. Troubleshooting and testing of the control circuit with approved insulated tools and test equipment can be performed prior to de-energizing.

6.14 Capacitors

6.14.1 When capacitors are disconnected, they must be considered energized until they have been short-circuited and grounded.

6.15 Elevated Equipment Near Energized Over-Head Lines

NOTE:	If the vehicle is in transit with its structure lowered, the Limited Approach Boundary can be reduced by 6 ft.

6.15.1 Where any vehicle or mechanical equipment structure will be elevated near energized over-head lines, they should be operated so that the Limited Approach is maintained.

6.16 Cables/ Wiring in Conduits and Raceways

6.16.1 When possible the circuit should be de-energized. If not, then provisions should be made to isolate/insulate the worker from exposed live parts.

6.16.2 When using a fish tape in conduits with energized conductor, the fish tape should be of the non-conductive type.

6.16.3 Man ways or duct bank access vaults should not be entered while energized unless provisions are made to isolate/insulate the worker from exposed live parts. Remove excess water prior to entry.

6.16.4 Cable deletions and mid-span cuts will be performed in accordance with STI-124.01.

6.17 Handling Fuses

6.17.1 When fuses are mounted in a fused disconnect switch, open the disconnect prior to removal of the fuses.

6.17.2 Approved insulated fuse pullers should be rated for the circuit nominal voltage.

6.17.3 25 kV Loop fused disconnect switches in pad mounted housings (PMHs) should be operated only with the source de-energized.

6.17.4 25 kV Loop overhead fused cutouts should only be operated de-energized OR Maintenance Director or plant manager approval must be obtained to operate energized under no load.

6.18 Clothing

NOTE: Standard OREX clothing when exposed to a flame melts, therefore, it cannot be worn when working on an exposed live part equal to or greater than 50 vac/vdc. Cotton Modesties are available from the Warehouse and should be worn in combination with FRC coverall/Flash suits, or FR Rated OREX, when working in area where both Flash and Contamination are possible. FRC coveralls and Flash suits are available from the Live Line Tool and EPE coordinator. FR Rated OREX clothing is available from the Warehouse.

6.18.1 National Fire Protection Association document NFPA-70E “Standard for Electrical Safety Requirements for Employee Workplaces” 2015 edition and OSHA 29 CFR 1910.269, “Electric Power Generation and Distribution,” published April 11, 2014 are used as the reference documents for determining hazards/risks and clothing requirements for protecting a worker from electrical arc or flash hazard.

6.18.2 The use of standard OREX or synthetic fabrics is allowed for 120V breaker operation where no exposed conductors exist in RCA areas / where RP prevents usage of natural clothing modesties.

6.18.3 FR Rated OREX clothing is allowed for use in a contaminated area when working on equipment that requires HCR 2 or less.

6.18.4 Employees whose job performance requires working within the flash protection boundary of an exposed live part **OR** an area where an electric arc could ignite flammable materials in the work area that could ignite the employee's clothing **OR** where molten metal or electric arc from faulted conductors could ignite the employee's clothing, as a minimum, must wear clothing per **Attachment 8.A** and comply with the following:

- Work clothing should include FRC long sleeve shirt/lab coat with a minimum ATPV rating of 4 cal/cm^2 and FRC Pants/Bib overalls or FRC-rated coveralls.

- Undergarments should be of 100% untreated natural fabric. Incidental amounts of elastic is permitted.

- When weather conditions warrant that outer wear be worn, these garments should be FRC when working on an exposed live part.

- Equipment may have postings that define the electrical safety Hazard Category and PPE requirements based on Arc Flash Calculations. Flame resistant clothing should have an arc rating equal to or greater than the calculated incident energy.

- Clothing made from fabric such as acetate, nylon, polyester, rayon, either alone or blends, and T-shirts with iron-on latex logos or decals (i.e. heat transfer graphics), should not be used for working on or near exposed energized equipment. **Exception**: Fiber blends that contain materials that melt, such as acetate, nylon, polyester, rayon, spandex, etc. are permitted if they have been tested by the manufacturer to meet requirements of ASTM F1506. These garments will be labeled as Flame Resistant (FR) by the manufacturer.

- Apparel must cover areas on the body exposed to a flash not covered by other PPE.

6.18.5 Voltage rated rubber gloves with leather protectors are considered appropriate for flash protection as well as shock protection.

6.18.6 ATPV gloves can be used for flash protection.

6.18.7 Flame resistant clothing (FRC) that becomes contaminated with oil, grease, paint, combustible material or torn should be removed from service.

6.18.8 When a personal fall arrest system is required to be used in conjunction with flame resistant clothing, fall protection devices must also have an arc flash/FR rating at 40 ($\pm$ 5) cal/cm^2.

6.18.9 Reference **Attachment 8A** for selection of the proper clothing for each Hazard/Risk category.

6.18.10 Sturdy leather shoes/boots normally provide a significant degree of protection to the feet. They are recommended for all tasks and should be used for Hazard/Risk category [1] and greater.

6.19 Climbing/Working on Electrical Equipment

6.19.1 No worker should climb on any electrical equipment unless it is in an electrically safe work condition, the work should be in direct support of the equipment. Additionally the worker should be observed by a supervisor.

6.19.2 Materials and tools should not be thrown to worker overhead. They should be raised and lowered with a hand line or with a hand line and insulated bucket.

6.19.3 Employees engaged in hoisting tools and materials should stand in a position such that they will not be endangered by accidentally dropping the load. Materials and tools should not be left unsecured in overhead positions.

6.19.4 When working on exposed live parts in support of upcoming maintenance, if material such as scaffolding is being used then extra precaution should be taken to ensure such material does not come in contact with exposed live parts. The limited approach boundary should be maintained.

7.0 FIGURES

None

8.0 ATTACHMENTS/FORMS

8A Hazard/Risk Matrix

8B Approach Boundaries

9.0 RECORDS

None

ATTACHMENT 8A
Page 1 of 15
Hazard/Risk Matrix

Typical Hazard with Clothing Descriptions		
Hazard/Risk Category	**Clothing Description FRC (Flame Resistant Clothing)**	**Minimum ATPV in cal/cm^2**
Hazard 1	Arc-rated long-sleeve shirt / Lab coat FR Rated OREX (Alternate) Arc-rated pants / Bib overall Arc-rated coverall (alternate) Arc-rated face shield or arc flash suit hood Arc-rated jacket, parka or rainwear (optional)	4
Hazard 2	Arc-rated long-sleeve shirt FR Rated OREX (Alternate) Arc-rated pants / Bib overall Arc-rated coverall (alternate) Arc-rated face shield with balaclava or arc flash suit hood Arc-rated jacket, parka or rainwear (optional)	8
Hazard 3	Shirt, jean and undergarments made of 100% untreated natural fabric. Arc-rated arc flash suit jacket Arc-rated flash suit pants Arc-rated flash suit hood Arc-rated jacket, parka or rainwear (optional)	25
Hazard 4	Shirt, jean and undergarments made of 100% untreated natural fabric. Arc-rated arc flash suit jacket Arc-rated flash suit pants Arc-rated flash suit hood Arc-rated jacket, parka or rainwear (optional)	40

NOTE: Employees shall wear hearing protection whenever working within the arc flash boundary.

ATTACHMENT 8A
Page 2 of 15
Hazard/Risk Matrix

Table of Approval Requirements

Approval Requirements for Work On Exposed Energized Conductors		
Activity	**≥ 50 Volts but ≤ 1000 Volts**	**> 1000 Volts**
Working on Live Parts	**RWO Supervisor** (Approved via Pre-job Brief)	**RWO Manager** (Flag in POD Frag)

Notes:

- **WHEN** equipment is KNOWN to be energized at > 1000V **AND** contact will be made, **THEN** RWO Manager approval is required and documented in the "Comments" section of the MG-38-1 form if not flagged in POD.
- Live-Dead-Lives for 480 VAC and 6.9 kV are pre-approved. Approval to start work is per RWO Supervisor via pre-job brief.

ATTACHMENT 8A
Page 3 of 15
Hazard/Risk Matrix

NOTES (Applicable to Pages 6-15 of Attachment 8A):

1. Number in [ ] after each task represents the hazard risk category.

2. After equipment is placed in an "Electrically Safe Work Condition", PPE requirements suitable for the task apply. (Shock (EPE) or flash (FPE) protection may not be needed)

3. Use of wrist grounding straps for ESD protection is allowed during printed circuit board removal/re-installation only. Wrist grounding straps MUST BE REMOVED prior to performing any other activity inside the limited approach boundary.

4. Some electronic equipment or components operate at high voltages and low amperage, therefore, they are not considered a flash hazard. Additionally if they can be worked with approved insulated tools and test equipment, the requirements in this table for use of voltage rated rubber gloves should be determined by the voltage being tested.

5. The requirements in this matrix assume equipment is energized, and work is done within the flash protection boundary.

6. Before reinstalling a breaker into the cubicle, workers should ensure the breaker is in the open position, and the springs are discharged if equipped.

7. When switching energized circuits or equipment, ensure enclosure doors are closed and hardware is secured. If the performance of PM or troubleshooting activities require connection of test equipment that would prevent complete closure of the enclosure door, then the proper flash protection boundary should be established prior to performance of the switching.

8. The use of voltage rated rubber gloves should be worn for shock protection, however, ATPV rated gloves can be worn for flash protection in lieu of voltage rated gloves when noted in **Attachment 8A**.

ATTACHMENT 8A
Page 4 of 15
Hazard/Risk Matrix

NOTES: (Cont.)

9. Scenarios where work is performed in the shop should be evaluated by the RWO Supervision.

10. Per ASTM F 1506: If fasteners or closures, for example, zippers, snaps or buttons, or a combination thereof, are used in a manner is which they are in contact with the skin, they can increase heat transfer and burn injury due to heat conduction or melting onto the skin. Therefore, a layer of fabric should be worn between the fastener and the skin. (The fabric should be 100% cotton.)

11. Ear canal hearing protection is required when working with-in a Hazard/Risk category [2] or greater.

12. When wearing a flash suit with hood, the oxygen beneath the hood can become deficient, therefore, there is a time restriction of two (2) minutes for their use. If the task being performed can be done safely within the two minutes then no additional measures must be taken. If the task cannot be performed within the two (2) minutes then a fresh air blower must be worn.

13. The use of standard OREX or synthetic fabrics is allowed for 120V breaker operation where no exposed conductors exist in RCA areas / where RP prevents usage of natural clothing modesties.

14. FR Rated OREX clothing should be limited to use in contaminated areas only.

ATTACHMENT 8A
Page 5 of 15
Hazard/Risk Matrix

NOTES: (Cont.)

15. If Arc Flash Warning Label is installed, then refer to label for additional FPE and expanded boundary requirements.

All 6.9KV bus feeders require 100 cal/cm^2 or greater electrical safety hazard gear.

1A1-1	2A1-1	1EA1-1
1A1-2	2A1-2	1EA1-2
1A2-1	2A2-1	1EA2-1
1A2-2	2A2-2	1EA2-2
1A3-1	2A3-1	2EA1-1
1A3-2	2A3-2	2EA1-2
1A4-1	2A4-1	2EA2-1
1A4-2	2A4-2	2EA2-2
XA1-1	XA1-2	

Certain 480V breakers require breaker configuration to reduce the hazard below the 55 cal/cm^2 electrical safety hazard gear. These breakers are the next breaker after a 6.9KV/480V transformer. If the 6.9KV feeder breaker to the transformer is open, then the 480V breaker can be racked out with the 55 cal/cm^2 electrical safety hazard gear.

1B1-1	1EB1-1	XB38-1
1B2-1	1EB2-1	XB1-1
1B3-1	1EB3-1	XB7-1
1B4-1	1EB4-1	
2B1-1	2EB1-1	
2B2-1	2EB2-1	
2B3-1	2EB3-1	
2B4-1	2EB4-1	

ATTACHMENT 8A
Page 6 of 15
Hazard/Risk Matrix

Storage Batteries, DC Switchboards, Chargers, Inverters > 50VDC < 250VDC

Boundaries:
- Flash - None ≤ 240 volts.
- Limited - 3 ft. 6 in. 50V - 250V.
- Restricted - Avoid Contact > 100 volts.

Task	Gloves	Insulated Tools	Clothing Minimum Requirements
Installing/removing M&TE			Natural Fabric
Removing/Installing energized fuse cartridges		Required	Natural Fabric
Testing/resetting/Clearing/Checking of Alarms/Lamps/Recorders			Natural Fabric
Operating switches in support of testing or Operations procedure			Natural Fabric
Live-Dead-Live checks		Required	Natural Fabric
Lifting or Landing “Live” leads rated equal to or less than 250VDC.		Required	Natural Fabric
Opening hinged doors to facilitate testing or alarm response.			Natural Fabric
Removing of bolted covers to expose live parts.			Natural Fabric
Station Batteries		Required	Natural Fabric

ATTACHMENT 8A
Page 7 of 15
Hazard/Risk Matrix

Misc. Equipment Supplied By (1 or 3 Phase) 50 to 240 Volts AC

Boundaries:
- Flash - None $\leq$ 240 volts.
- Limited - 3 ft. 6 in. > 50 volts.
- Restricted - Avoid Contact > 50 volts.

Task	Gloves	Insulated Tools	Clothing Minimum Requirements
Installing/removing M&TE			Natural Fabric
Operating circuit breakers/disconnects (Covers on or off)			Natural Fabric
Removing/Installing fuse cartridges/blocks		Required	Natural Fabric
Live-Dead-Live checks > 120V nominal [1]	Class 0 or 00	Required	FRC/Face Shield $\geq$ 4 cal/cm^2
Remove/Install molded case circuit breakers **Note: 6**		Required	Natural Fabric
Lifting or Landing "Live" leads rated > 120V nominal [1]	Class 0 or 00	Required	FRC/Face Shield $\geq$ 4 cal/cm^2
Emergency lighting battery replacement and inspection			Natural Fabric
Thermography outside of limited approach boundary			Natural Fabric
Removing/installing, opening/closing bolted or hinged covers to expose live parts [1]	Class 0 or 00		FRC/Face Shield $\geq$ 4 cal/cm^2
Work on control circuits with exposed energized electrical conductors and circuit parts, 120V or below, without any other exposed energized equipment over 120V including opening of hinged covers to gain access		Required	Natural Fabric
Work on control circuits with exposed energized electrical conductors and circuit parts, greater than 120V	Class 0 or 00	Required	FRC/Face Shield $\geq$ 4 cal/cm^2

ATTACHMENT 8A
Page 8 of 15
Hazard/Risk Matrix

Panel/Switchboards & Misc. Equipment (1 or 3 Phase) 240 to 1000 Volts AC

Boundaries:
- Flash - 4 ft.
- Limited - 3 ft.- 6 in.
- Restricted - 1 ft. 1 in.

Task	Gloves	Insulated Tools	Clothing Minimum Requirements
Operating circuit breakers/disconnects (Covers on)			Natural Fabric
Operating circuit breakers/disconnects (Covers Off) [2] **Note: 11**	Class 0 or 00		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Remove/install molded case circuit breakers [2] **Notes: 6,11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Racking RX trip breaker from disconnect to remove in support of breaker removal [2] **Note: 11**	Class 0 or 00 **Note: 8**		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Removing/installing RX trip breaker with exposed live parts. [2] **Notes: 6,11**	Class 0 or 00 **Note: 8**		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Removing/Installing fuse cartridges/blocks [2] **Note: 11**		Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Live-Dead-Live checks [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Lifting or landing “Live” leads rated equal to or greater than 240 vac/vdc [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Installing/removing M&TE to test point connections. Pushing the reset button on circuit cards or installing/removing circuit cards in the Rod Control Power Cabinets.			Natural Fabric
Installing/removing M&TE [2] **Note:11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Thermography outside of limited approach boundary			Natural Fabric
Removing/Opening bolted covers to expose live parts [2] **Note: 11**	Class 0 or 00		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Opening hinged covers to expose live parts			FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Connecting/disconnecting equipment from an energized welding receptacle without disconnect [2] **Note: 11**	Class 0 or 00		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Removing/Opening bolted/hinged covers on MOV’s to expose live parts. [2] **Note: 11**	Class 0 or 00		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Obtaining voltage/current readings in upper section of SCI Battery Chargers [2] **Note : 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2

ATTACHMENT 8A
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Hazard/Risk Matrix

Motor Control Centers (MCC's) 480 Volts

Boundaries:
- Flash - 10 ft. for removing/installing buckets, 4 ft. for other tasks
- Limited - 3 ft.- 6 in.
- Restricted - 1 ft. 1 in.

Task	Gloves	Insulated Tools	Clothing Minimum Requirements
Removing/installing starter buckets [4] **Notes: 6,11**	Class 0 or 00	Required	Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note: 12**
Removing/Installing fuse cartridges/blocks [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$8 cal/cm^2
Cycling transfer switch with door closed			Natural Fabric
Cycling transfer switch with door open with exposed live parts [2] **Note: 11**	Class 0 or 00 **Note: 8**		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Installing/removing M&TE in support of MOV testing with exposed live parts [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Live-Dead-Live checks [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Lifting or Landing "Live" leads rated equal to or greater than 240 vac/vdc [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Meter and relay calibration in relaying compartment			Natural Fabric
Installing/removing M&TE with exposed live parts [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Thermography outside of limited approach boundary			Natural Fabric
Removing bolted covers to expose live parts [4] **Note: 11**	Class 0 or 00		Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note:12**
Opening hinged covers to expose live parts [2] **Note: 11**	Class 0 or 00		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2

ATTACHMENT 8A
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Hazard/Risk Matrix

Switchgear 480 Volts

Boundaries:
- Flash - 20 ft. for racking of breakers, 4 ft. for other task (Refer to Arc Flash Warning label, if installed)
- Limited - 3 ft.- 6 in.
- Restricted - 1 ft. 1 in.

Task	**Gloves**	**Insulated Tools**	**Clothing Minimum Requirements** (Refer to Arc Flash Warning label, if installed)
Racking breaker from disconnect to remove in support of breaker removal (door open) [4] **Note: 11**	ATPV		Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note:12, 15**
Removing/installing breaker with exposed live parts. [4] **Note: 11**	ATPV		Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note:12, 15**
Installation/removal of electrical protective equipment with exposed live parts [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Removing/Installing fuse cartridges/blocks in auxiliary compartments		Required	Natural Fabric
Live-Dead-Live checks [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Installing/removing M&TE with exposed live parts [2] **Note: 11**	Class 0 or 00		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Lifting or landing “Live” leads rated equal to or greater than 240 vac/vdc. [2] **Note: 11**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2
Meter and relay calibration within auxiliary compartments			Natural Fabric
Thermography outside of limited approach boundary			Natural Fabric
Removing bolted covers to expose live parts [3] **Note: 11**	Class 0 or 00		FRC/ Hood $\geq$ 40 cal/cm^2 **Note:12, 15**
Opening hinged covers to expose live parts [2] **Note: 11**			FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2

ATTACHMENT 8A
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Hazard/Risk Matrix

Switchgear/Equipment 750 volts to 15 Kv

Boundaries:
- Flash - 40 ft. (Refer to Arc Flash Warning label, if installed)
- Limited - 5 ft.
- Restricted - 2 ft.- 2 in.

Task	Gloves	Insulated Tools	Clothing Minimum Requirements (Refer to Arc Flash Warning label, if installed)
Removing/Installing fuse cartridges/blocks in upper cubicle		Required	Natural Fabric
Live-Dead-Live checks in upper cubicle		Required	Natural Fabric
Installing/removing M&TE in upper cubicle			Natural Fabric
Lifting or landing “Live” leads rated equal to or less than 240 vac/vdc in upper cubicle		Required	Natural Fabric
Live-Dead-Live checks of exposed live busbar/stabs [4] **Note: 11**	Class 2	Required	Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12, 15**
Installation/Removal of grounding breaker/devices [4] **Note: 11**	Class 2		Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12, 15**
Meter and Relay calibration on door or top cubicle compartment (breaker open)			Natural Fabric
Megger or Hi Pot testing of load stabs with half shutter cover installed	Class 2		Natural Fabric
Removing bolted covers to expose live parts [4] **Note: 11**	Class 2		Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12, 15**
Opening hinged covers to expose live parts [4] **Note: 11**	Class 2		FRC/ Hood $\geq$ 50 cal/cm^2 **Note:12, 15**
Opening energized potential transformer compartments associated with incoming feeders [4] **Note: 11**	Class 2		Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12, 15**
Opening switchgear potential transformer compartment with switchgear in (ESWC)			Natural Fabric
Installation/removal of full or half shutter cover with cubicle shutter closed			Natural Fabric
Thermography outside Limited Approach Boundary			Natural Fabric

ATTACHMENT 8A
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Hazard/Risk Matrix

Switchgear/Equipment 15 to 36 Kv

Boundaries:
- Flash - 40 ft.
- Limited - 6 ft.
- Restricted - 2 ft.- 7 in.

Task	Gloves	Insulated Tools	Clothing Minimum Requirements
Removing/opening bolted/hinged covers to expose live parts [4] **Note:11**	Class 3		Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12**
Racking out Iso-phase bus potential transformers for fuse removal **Note:11**			Natural Fabric
Live-Dead-Live checks of Iso-phase busbar/stabs in support of ground installation [4] **Note:11**	Class 3	Required	Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12**
Installation of grounds on Iso-phase busbar. [4] **Note:11**	Class 3	Required	Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12**
Live-Dead-Live checks of Pad mounted transformer/disconnect switch with exposed live parts [4] **Note:11**	Class 3	Required	Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12**
Internal inspection of 25 Kv loop pad mounted transformer/disconnect switch with exposed live parts [4] **Note:11**	Class 3		Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12**
Megger or Hi Pot testing of Iso-phase bus	Class 3		Natural Fabric
Operating 25 Kv loop pole mounted disconnect switches from bucket truck with live line tool **Note:11**	Class 3	Required	Natural Fabric
Operating 25 Kv loop pole mounted disconnect switches from ground with live line tool.	Class 3	Required	Natural Fabric
Operating 25 Kv loop pole mounted disconnect switches from ground with ganged operator	Class 3		Natural Fabric
Operating 25 Kv loop pad mounted disconnect switch (doors closed)			Natural Fabric

ATTACHMENT 8A
Page 13 of 15
Hazard/Risk Matrix

Switchgear/Equipment 15 to 36 Kv

Boundaries:
- Flash - 40 ft.
- Limited - 6 ft.
- Restricted - 2 ft.- 7 in.

Task	Gloves	Insulated Tools	Clothing Minimum Requirements
Thermography of pad mounted switchgear/transformer with exposed live parts [4] **Note:11**	Class 3 **Note: 8**		Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12**
Insulated cable examination, in open area [4] **Note:11**	Class 3	Required	Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12**
Insulated cable examination, in manhole or other confined space [4] **Note:11**	Class 3	Required	Flash Suit/Hood $\geq$ 50 cal/cm^2 **Note:12**

ATTACHMENT 8A
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Hazard/Risk Matrix

[L]	**Operations Department Tasks For Varying Voltages**					
Task	**Location(s)**	**Hazard Level**	**Gloves**	**Insulated tools**	**Minimum Clothing**	**Boundary**
Pulling Fuses	Term/control room Cabinets			Required	Natural Fabric	Avoid Contact
	MCC Bucket/Cubicles	[2] **Ear Plugs**	Class 0 or 00	Required	FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2	4 ft
	480/6900 Swgr's Aux. Compt.			Required	Natural Fabric	Avoid Contact
Opening hinged doors to facilitate testing or alarm response	AMSAC,SSSS, SSPS,RX Trip or similar cabinets	**Notes: A, D**			Natural Fabric	Avoid Contact
Racking breakers	Rx Trip Swgr	[2] **Ear Plugs** **Note: A**	ATPV		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2	4 ft
	480 V Swgr load breaker	[4] **Ear Plugs** **Note: C**	ATPV		Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note: 15**	10 ft
	6.9 KV Swgr door closed	[4] **Ear Plugs** **Note: B**	ATPV		Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note: 15**	20 ft

NOTES A-D APPLY TO PAGES 14 and 15 ONLY

Notes: A. This section applies to the following procedures: ETP-447A/B, ETP-448A/B, SOP-702A/B, OPT-445A/B, OPT-446A/B, OPT-447A/B and OPT-448A/B.

B. This section applies to the following procedures: SOP-603A/B (Att. 1) and SOP-614A/B.

C. This section applies to the following procedures: SOP 604A (Att. 12) and SOP-604B (Att. 5).

D. This section applies to the following procedures: SOP-904 and OPT-220.

ATTACHMENT 8A
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Hazard/Risk Matrix

[L]	**Operations Department Tasks For Varying Voltages**					
Task	**Location(s)**	**Hazard Level**	**Gloves**	**Insulated tools**	**Minimum Clothing**	**Boundary**
Breaker Operation	120/240 vac/vdc Bkrs **Note:13**				Natural	
	MCC door closed				Natural	
	MCC door open	[2] **Ear Plugs**	ATPV		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2	4 ft
	Cycling MCC transfer switch door closed				Natural	
	Cycling MCC transfer switch door open	[2] **Ear Plugs**	ATPV		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2	4 ft
	Rx Trip Swgr	[2] **Ear Plugs**	ATPV		FRC/Face Shield/Balaclava $\geq$ 8 cal/cm^2	4 ft
	480 V Swgr door open	[4] **Ear Plugs**	ATPV		Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note:12, 15**	10 ft
	6.9 KV Swgr door open / closed	[4] **Ear Plugs Note: B**	ATPV		Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note:12, 15**	40 ft
Vent Chiller Disconnect Operation	Vent Chillers 7 thru 9	[4] **Ear Plugs Note: B**	ATPV		Flash Suit / Hood $\geq$ 50 cal/cm^2 **Note:12**	40 ft
Manual Manipulation of 42 Contactor	480V MCC buckets/cubicles	[2] **Ear Plugs**	Class 0 or 00	N/A	FRC/Face Shield/Balaclava > 8 cal/cm^2	4 ft

<u>NOTES A-D APPLY TO PAGES 14 and 15 ONLY</u>

Note B: This section applies to the following procedures: SOP-603A/B (Att. 1) and SOP-614A/B.

ATTACHMENT 8B
Page 1 of 1

Approach Boundaries

APPROACH BOUNDARIES FOR SHOCK PROTECTION		
Nominal System Voltage Range	**Limited Approach Boundary (Unqualified Electrical Workers Require Escort)**	**Restricted Approach Boundary (Qualified Electrical Workers Only)**
Phase-to-Phase	**Exposed Fixed Circuit Part**	**Includes Inadvertent Movement**
Less than 50 V	NA	NA
50 V to 300 V	3 ft. 6 in.	Avoid Contact
301 V to 750 V	3 ft. 6 in.	1 ft. 1 in.
751 V to 5 kV	5 ft. 0 in.	2 ft. 1 in.
5.1 kV to 15 kV	5 ft. 0 in.	2 ft. 2 in.
15.1 kV to 36 kV	6 ft. 0 in.	2 ft. 7 in.
36.1 kV to 46 kV	8 ft.	2 ft. 10 in.
46.1 kV to 72.5 kV	8 ft.	3 ft. 4 in.
72.6 kV to 121 kV	8ft.	3 ft. 4 in.
121.1 kV to 145 kV	10 ft.	3 ft. 10 in.
145.1 kV to 169 kV	11 ft. 8 in.	4 ft. 4 in.
230 kV to 242 kV	13 ft.	5 ft. 8 in.
345 kV to 362 kV	15 ft. 4 in.	9 ft. 1 in.
500 kV to 552 kV	19 ft.	11 ft. 11 in.
700 kV to 765 kV	23 ft. 9 in.	15 ft. 10 in.

FLASH PROTECTION BOUNDARIES

DEFAULT FLASH PROTECTION BOUNDARIES (FOR TASK SPECIFIC FLASH BOUNDARIES, SEE HAZARD/RISK MATRIX)		
VOLTAGE	TASK	DISTANCE
0-50	ANY	Not specified
51-240	ANY	4 ft.
241-600	ANY	4-10 ft.
601 - 750	ANY	10 ft.
>1000 V	ANY	40 ft.

Rev/PCN	Affected Pages	Description of Change
2/0	All	Revised procedure to reflect the requirements of NFPA 70E 2009 Edition, “Standards for Electrical Safety Requirements for Employee Workplaces.” Procedure also upgraded to current formatting and level of use standards.
2/1	30	Attachment 8A, “Table of Approval Requirements,” has been modified: 1) Work on exposed energized conductors ≥ 50 Volts but ≤ 600 Volts is approved by the RWO Supervisor via pre-job brief; 2) Work on exposed energized conductors > 600 Volts is approved by the RWO Manager. (Ref: AI-CR-2011-001819-1) NFPA-70E guidelines state that an RWO Manager can approve work on > 600 Volts. Per CPNPP Maintenance Director, manager approval is adequate for this task
2/2	1, 5, 11, 13, 26, 27, 29, 32, 35, 36, 37, 39, 41	This PCN incorporates NFPA 70E - 2012 Edition changes. Ref: CR-2011-011865.
2/3	1, 5, 11, 12	Editorial PCN to add reference 3.27 and to add commitment number and designator to steps 6.1.1.C and 6.1.3.1. Ref: CR-2012-011596.
2/4	1, 11, 17, 29, 33, 34, 40, 41, 43	This PCN incorporates NFPA 70E - 2012 Edition changes. Ref: CR-2013-001624.
2/5	1, 11	Deleted MAT Code EM11.GEL.YI2 from proficiency demonstration requirement as it has been consolidated with EM11.GEL.YI6. Corrected commitment number (typographical error from PCN #4).
2/6	1, 5, 5.1, 6, 7, 8, 9, 10, 17, 29, 39, 39.1	This PCN incorporates NFPA 70E - 2012 Edition changes. Ref: CR-2013-006414.
2/7	1, 5, 12, 25	Added references to new procedure STI-124.01 for cable deletions and mid-span cuts, added caution statement regarding ineffectiveness of proximity testers on shielded cable, updated Employee Use box. Ref: CR-2013-012287.
2/8	1, 7, 8, 9, 26, 26.1, 29, 32, 36, 39.1	Added definitions for standard and FR Rated OREX. Allowed the use of OREX as anti-contamination clothing when performing electrical activities in areas where voltages still exist. Ref. CR-2014-003681. Relocated “Note” on page 26 for clarity.
2/9	1, 5, 5.1, 11,12	Updated Employee Use box. Added references 3.29 and 3.30. Re-located steps 4.0 - 4.3 to page 5.1 to prevent over-crowding. Added commitment number 4924624 to steps 6.1.1.C and 6.1.3.1. Ref. AI-CR-2014-008728-8.
2/10	1, 5, 26, 26.1, 27	Updated Employee Use box. Added reference 3.31. Enhanced procedure to align with the changes made to the last OSHA regulation published April 11, 2014. Ref: AI-CR-2014-008117-1.
2/11	1,29	Deleted “rayon” from Clothing Description Hazard 0 on Attachment 8A as the conservative approach is to wear only natural fibers. Ref. CR-2015-006387. Updated Employee Use box.
2/12	1, 5, 26, 30	Added step 6.17.3 to allow operation of 25kV loop fused disconnect switches in PMHs only with source de-energized. Added step 6.17.4 to allow operation of de-energized 25kV loop overhead fused cutouts or with approval from Maintenance Director or plant manager if energized. Added clarification to Attachment 8A that work inside prohibited approach boundaries is considered work on exposed energized equipment and requires RWO manager approval. Added CR-2015-006401 as a Reference.
3/0	All	Incorporated changes from NFPA 70E 2015 Edition. Ref. CR-2015-010487. Added de-metalling requirements.

Initial Conditions: Given the following conditions:

XCICE1, VENTILATION CHILLER X-01 COMPRESSOR MOTOR BREAKER located at 1EA1/4/BKR, is required to be racked from 'Connect' to 'Disconnect' in support of breaker tagging order.

Initiating Cue: The Shift Manager directs you to DETERMINE the following in accordance with STA-124, Electrical Safe Work Practices:

- Hazard Risk Category: 4
- Minimum ATPV in cal/cm^2: >50 cal/cm2
- Flash Boundary: 20 ft
- Limited Approach Boundary: 5 ft 0 in
- Restricted Approach Boundary: 2 ft 2 in
- Arc flash suit/hood required:

  YES NO
- Ear canal hearing protection required:

  YES NO
- Insulated tools required:

  YES NO

Facility: CPNPP JPM # NRC RA3 Task # RO4108A K/A # 2.2.12 3.7 / 4.1

Title: Perform Control Room Air Conditioning System Surveillance Data

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Both Units are operating at 100% power with all controls in Automatic.
- Train B Control Room Air Conditioning System is being tested per OPT-116, CR AC SYSTEM.
- The 30 minute run time since completion of the Prerequisites is complete.
- The following parameters are observed:
    - CR A/C UNIT 03- X-PI-3585A reads 150 psig and is operating 45% unloaded
    - CR A/C UNIT 04 -X-PI-3586A reads 160 psig and is operating 35% unloaded
    - X-TR-4123 reads 75°F
    - X-TI-5933 reads 63°F
    - X-TI-5734 reads 64°F
    - X-TI-5735 reads 62°F

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- COMPLETE the Control Room Air Conditioning System surveillance per OPT-116, CR AC SYSTEM
- RECORD and COMPLETE all data on OPT-116-1, CR AC System Data Sheet

Task Standard: UTILIZED OPT-116, RECORDED data on OPT-116-1, PLOTTED air conditioning unit cooling capacity, and DETERMINED Acceptance Criteria met.

Ref. Materials: OPT-116, CR AC System, Rev. 5.
OPT-116-1, CR AC System Data Sheet, Rev. 5.

Validation Time: 12 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ____________

CLASSROOM SETUP

EXAMINER:

PROVIDE the examinee with a copy of:

- **OPT-116, CR AC System (Procedure)**
- **OPT-116-1, CR AC System Data Sheet (Form)**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from OPT-116, Section 8.0.**
Perform Step: 1 8.3 & 1st bullet	RECORD the following: • X-TR-4123, outside temperature (10M PRI) (X-CV-05)
Standard:	RECORDED X-TR-4123, outside temperature of 75°F on OPT-116-1 and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2 8.3 & 2nd bullet	RECORD the following: • X-TI-5933 ECB EXH TEMP (X-CV-01)
Standard:	RECORDED X-TI-5933, ECB EXH TEMP of 63°F, on OPT-116-1 and COMPARED to Required Test Conditions of ≥ 60 degrees and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3 8.3 & 3rd bullet	RECORD the following: • X-TI-5734, AB EXH TEMP EL-852' 6" (X-CV-03)
Standard:	RECORDED X-TI-5734, AB EXH TEMP of 64°F on OPT-116-1 and COMPARED to Required Test Conditions of ≥ 60 degrees and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4 8.3 & 4th bullet	RECORD the following: • X-TI-5735, AB EXH TEMP EL-831' 6" (X-CV-03)
Standard:	RECORDED X-TI-5735, AB EXH TEMP of 62°F, on OPT-116-1 and COMPARED to Required Test Conditions of ≥ 60 degrees and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 5 8.3 & 5th bullet	RECORD the following: • Compressor discharge pressures for operating A/C units. • CR A/C Unit 03 (X-PI-3585A)
Standard:	RECORDED CR A/C Unit 03 (X-PI-3585A) pressure of 150 psig on OPT-116-1 and COMPARED to Required Test Conditions of < 170 psig and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 6 8.3 & 5th bullet	RECORD the following: • Compressor discharge pressures for operating A/C units • CR A/C Unit 04 (X-PI-3586A)
Standard:	RECORDED CR A/C Unit 04 (X-PI-3586A) pressure of 160 psig on OPT-116-1 and COMPARED to Required Test Conditions of < 170 psig and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Examiner Cue:	**If asked about Independent Verification (IV), REPORT to proceed as if the IV has been performed.**
Perform Step: 7√ 8.4	VERIFY the above readings are within the specified limits. If any of the above readings are NOT within the specified limits, this test should be terminated and restarted when the above conditions can be met.
Standard:	VERIFIED that all readings are within limits and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 8 8.5	RECORD % unloaded (lights on A/C Unit Control Panel) for both operating A/C units. • A/C UNIT 03
Standard:	RECORDED A/C UNIT 03 % unloaded of 45% on OPT-116-1 and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 9 8.5	RECORD % unloaded (lights on A/C Unit Control Panel) for both operating A/C units. • A/C UNIT 04
Standard:	RECORDED A/C UNIT 04 % unloaded of 35% on OPT-116-1 and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 10√ 8.6	CALCULATE the average % unloaded by adding the % unloaded from the operating compressors and dividing by 2.
Standard:	ADDED 45% and 35% and DIVIDED by 2 to yield an average of 40%; RECORDED on OPT-116-1 and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 11 8.7	Using outside temperature (Step 8.3) and the calculated average compressor cooling capacity availability (Step 8.6), VERIFY operation is above the curve (Figure 1) in the data sheet, AND RECORD test results.
Standard:	PLOTTED the intersection point for 75 degrees and 40% on Figure 1 and COMPARED to the acceptability curve.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 12√ 8.7	Using outside temperature (Step 8.3) and the calculated average compressor cooling capacity availability (Step 8.6), VERIFY operation is above the curve (Figure 1) in the data sheet, AND RECORD test results.
Standard:	VERIFIED plotted point is BELOW the curve on Figure 1 and CIRCLED BELOW then UNSAT on OPT-116-1 and INITIALED.
Terminating Cue:	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Both Units are operating at 100% power with all controls in Automatic.**
- **Train B Control Room Air Conditioning System is being tested per OPT-116, CR AC SYSTEM.**
- **The 30 minute run time since completion of the Prerequisites is complete.**
- **The following parameters are observed:**
  - **CR A/C UNIT 03- X-PI-3585A reads 150 psig and is operating 45% unloaded.**
  - **CR A/C UNIT 04 -X-PI-3586A reads 160 psig and is operating 35% unloaded.**
  - **X-TR-4123 reads 75°F.**
  - **X-TI-5933 reads 63°F.**
  - **X-TI-5734 reads 64°F.**
  - **X-TI-5735 reads 62°F.**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **COMPLETE the Control Room Air Conditioning System surveillance per OPT-116, CR AC SYSTEM.**
- **RECORD and COMPLETE all data on OPT-116-1, CR AC System Data Sheet**

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1&2

OPERATIONS TESTING MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS Today / JR LATEST PCN/EFFECTIVE DATE ______ / ______

LEVEL OF USE:
CONTINUOUS USE

QUALITY RELATED

CR AC SYSTEM

PROCEDURE NO. OPT-116

REVISION NO. 5

EFFECTIVE DATE: 7/14/14 1200

SURVEILLANCE TEST

PREPARED BY (Print): J.D. STONE EXT: 0564

TECHNICAL REVIEW BY (Print) EDITORIAL REVISION EXT: NA

APPROVED BY: Joe Ricks DATE: 7/3/14
DIRECTOR, OPERATIONS

1.0 PURPOSE

This procedure verifies each CRACS train has the capability to remove the assumed heat load satisfying SR 3.7.11.1 requirements.

2.0 ACCEPTANCE AND REVIEW CRITERIA

2.1 Acceptance Criteria

2.1.1 The acceptance criteria are listed on the data sheet.

2.2 Review Criteria

None

3.0 DEFINITIONS/ACRONYMS

3.1 CRACS - Control Room Air Conditioning System

4.0 REFERENCES

4.1.1 Technical Specification 3.7.11, Control Room Air Conditioning System (CRACS)

4.1.2 Technical Requirements Manual 13.7.36, Area Temperature Monitoring"

4.2 Development

4.2.1 FSAR Section 6.4, Habitability System

4.2.2 FSAR Section 9.4, Air Conditioning, Heating, Cooling, and Ventilation Systems

4.2.3 DBD-ME-304, Control Room Air Conditioning System

4.2.4 M1-0304, Flow Diagram Ventilation Control Room & Office & Service Area

4.2.5 M1-0308, Flow Diagram Ventilation Control Room Mode of Operation

4.2.6 ABN-203, Control Room Ventilation System Malfunction

5.0 PRECAUTIONS, LIMITATIONS AND NOTES

5.1 Precautions

None

5.2 Limitations

5.2.1 Two CRACS trains shall be OPERABLE per the requirements of TS 3.7.11.

5.2.2 The temperature limits for normal conditions shall be per the TRM 13.7.36.

5.3 Notes

- A time delay prevents the start of a CRAC when taken from PULL-OUT position. Following removal from PULL-OUT, take the handswitch to STOP position. The CRAC may then be started following time delay dropout (approximately thirty seconds).

6.0 PREREQUISITES

☒ • This test may be performed with both units in any MODE.

☒ • When outside ambient temperature is <30°F this test may be performed with only 1 A/C unit operating. This is NOT the preferred method.

☒ • WHEN outside ambient temperature is ≥30°F (X-TR-4123), the CR A/C units should be aligned as follows:

Train A Test

N/A ☐ A/C Units 01 & 02 operating

☒ A/C Units 03 & 04 shutdown

Train B Test

☒ A/C Units 03 & 04 operating

☒ A/C Units 01 & 02 shutdown

☒ • The Control Building exhaust temperature (X-TI-5933) AND Auxiliary Building exhaust temperatures (X-TI-5734, X-TI-5735) from elevations 852" 6" and 831' 6" are ≥60°F.

☒ • The compressor discharge pressures are <170 psig for the operating A/C units.

☒ • RECORD the time and date the above prerequisites are verified to be met. These conditions shall be met for at least 30 minutes prior to starting Section 8.0.

7.0 TEST EQUIPMENT

None

8.0 INSTRUCTIONS

> NOTE: Record all data on Form OPT-116-1.

☑ 8.1 RECORD CR A/C Unit(s) being tested.

☑ 8.2 RECORD time and date (shall be ≥30 min. from time recorded in Prerequisite section).

8.3 RECORD the following:

- ☐ X-TR-4123, outside temperature (10M PRI) (X-CV-05)
- ☐ X-TI-5933, ECB EXH TEMP (X-CV-01)
- ☐ X-TI-5734, AB EXH TEMP EL-852' 6" (X-CV-03)
- ☐ X-TI-5735, AB EXH TEMP EL-831' 6" (X-CV-03)
- ☐ Compressor discharge pressures for operating A/C units.

  CR A/C Unit 01 (X-PI-3583A)
  CR A/C Unit 02 (X-PI-3584A)
  CR A/C Unit 03 (X-PI-3585A)
  CR A/C Unit 04 (X-PI-3586A)

☐ 8.4 VERIFY the above readings are within the specified limits. If any of the above readings are NOT within the specified limits, this test should be terminated and restarted when the above conditions can be met.

☐ 8.5 RECORD % unloaded (lights on A/C Unit Control Panel) for both operating A/C units.

[IV] ☐ 8.6 CALCULATE the average % unloaded by adding the % unloaded from the operating compressors and dividing by 2.

A/C UNIT NO.__________ A/C UNIT NO.__________

$$\frac{\text{\% UNLOADED\_\_\_\_\_\_\_\_\_} + \text{\% UNLOADED\_\_\_\_\_\_\_\_\_}}{2} = \text{TRAIN AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY}$$

> NOTE: Operation above the curve contained in the data sheet verifies that the CRACS has the capability to remove the assumed heat load satisfying SR 3.7.11.1 requirements.

☐ 8.7 Using outside temperature (Step 8.3) and the calculated average compressor cooling capacity availability (Step 8.6), VERIFY operation is above the curve (Figure 1) in the data sheet, AND RECORD test results. (CONTACT Engineering if this test was performed at ambient outside temperature <20°F to determine test results).

☐ 8.8 ALIGN CR A/C Units as directed by the Shift Manager (normally per appropriate workweek as designated in OWI-409, Equipment Rotation Program).

9.0 RESTORATION

None

10.0 ATTACHMENTS/FORMS

10.1 Attachments

None

10.2 Forms

10.2.1 OPT-116-1, CR A/C System Data Sheet

CR A/C SYSTEM DATA SHEET

STEP		OBSERVED	REQUIRED TEST CONDITIONS	INITIALS
6.0	PREREQUISITES MET	N/A	N/A	JR
	AND TIME/DATE	1 hour ago/Today	N/A	JR
8.1	CR A/C UNITS BEING TESTED	3 & 4	N/A	JR
8.2	TIME AND DATE	Now/Today	≥30 MIN PAST STEP 6.0	JR
8.3	RECORD THE FOLLOWING:			
	• X-TR-4123 OUTSIDE TEMPERATURE	______	N/A	______
	• X-TI-5933	______	≥60°F	______
	• X-TI-5734	______	≥60°F	______
	• X-TI-5735	______	≥60°F	______
	• COMPRESSOR DISCHARGE PRESSURES (N/A for shutdown units)			
	CR A/C UNIT 01 (X-PI-3583A)	______	<170 PSIG	______
	CR A/C UNIT 02 (X-PI-3584A)	______	<170 PSIG	______
	CR A/C UNIT 03 (X-PI-3585A)	______	<170 PSIG	______
	CR A/C UNIT 04 (X-PI-3586A)	______	<170 PSIG	______
8.4	ALL ABOVE REQUIRED TEST CONDITIONS MET	N/A	NOTE 1	______

NOTE 1: If test conditions are not met, TERMINATE test at this point. Test shall be restarted when conditions can be met.

CR A/C SYSTEM DATA SHEET

STEP		OBSERVED	INITIALS
8.5	A/C UNIT % UNLOADED (N/A for shutdown units)		
	A/C UNIT 01	________	________
	A/C UNIT 02	________	________
	A/C UNIT 03	________	________
	A/C UNIT 04	________	________
8.6	CALCULATE AVERAGE		
	A/C UNIT NO.________ A/C UNIT NO.________		________
	(% UNLOADED________ + % UNLOADED________) / 2	= ____________ TRAIN AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY	________ VERIFIED
8.7	COMPARE OUTSIDE TEMP (STEP 8.3) AND AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY (STEP 8.6) TO CURVE (FIGURE 1)	OPERATION ABOVE/BELOW CURVE	________
	ACCEPTANCE CRITERIA SAT IF OPERATION IS ABOVE CURVE	SAT/UNSAT	________

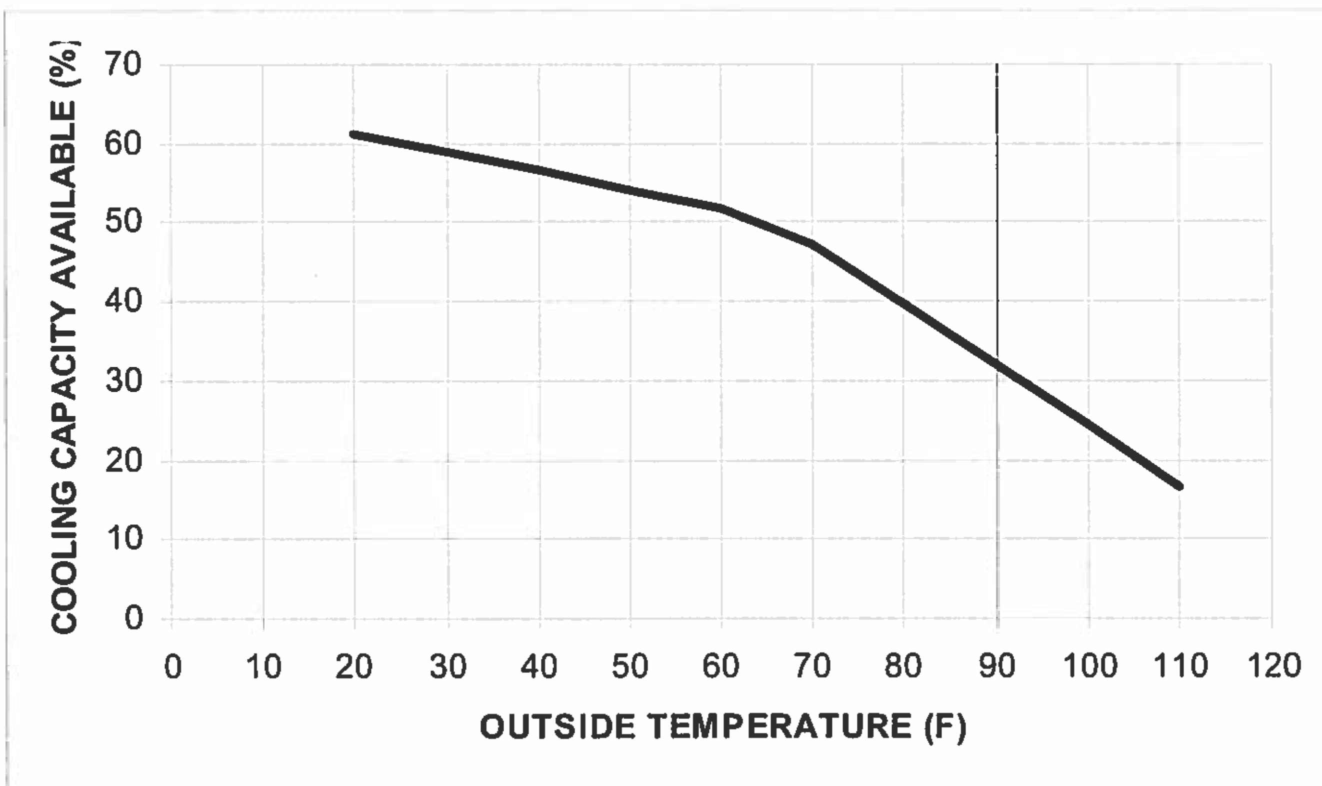
CR A/C SYSTEM DATA SHEET

FIGURE 1

OUTSIDE TEMPERATURE	PERCENT UNLOADED
	16.7
110	24.3
100	32.0
90	39.6
80	47.2
70	51.7
60	54.1
50	56.5
40	58.9
30	61.3
20	

CONTROL ROOM HVAC MINIMUM REQUIRED AVAILABILITY

THE UNLOADED COMBINED AVERAGE OF THE TWO 50% CONTROL ROOM HVAC UNITS MUST BE ABOVE THE CURVE REPRESENTED BELOW:



CR A/C SYSTEM DATA SHEET

COMMENTS/DISCREPANCIES:____

____

____

____

____

____

CORRECTIVE ACTIONS:____

____

____

____

____

____

PERFORMED BY:____________________________________DATE:______________
SIGNATURE

REVIEWED BY:_____________________________________DATE:______________
OPERATIONS MANAGEMENT

CR A/C SYSTEM DATA SHEET

STEP		OBSERVED	REQUIRED TEST CONDITIONS	INITIALS
6.0	PREREQUISITES MET	N/A	N/A	JR
	AND TIME/DATE	1 hour ago/Today	N/A	JR
8.1	CR A/C UNITS BEING TESTED	3 & 4	N/A	JR
8.2	TIME AND DATE	Now/Today	≥30 MIN PAST STEP 6.0	JR
8.3	RECORD THE FOLLOWING:			
	• X-TR-4123 OUTSIDE TEMPERATURE	75	N/A	
	• X-TI-5933	63	≥60°F	
	• X-TI-5734	64	≥60°F	
	• X-TI-5735	62	≥60°F	
	• COMPRESSOR DISCHARGE PRESSURES (N/A for shutdown units)			
	CR A/C UNIT 01 (X-PI-3583A)	N/A	<170 PSIG	
	CR A/C UNIT 02 (X-PI-3584A)	N/A	<170 PSIG	
	CR A/C UNIT 03 (X-PI-3585A)	150	<170 PSIG	
	CR A/C UNIT 04 (X-PI-3586A)	160	<170 PSIG	
8.4	ALL ABOVE REQUIRED TEST CONDITIONS MET	N/A	NOTE 1	Initials

NOTE 1: If test conditions are not met, TERMINATE test at this point. Test shall be restarted when conditions can be met.

CR A/C SYSTEM DATA SHEET

STEP		OBSERVED	INITIALS
8.5	A/C UNIT % UNLOADED (N/A for shutdown units)		
	A/C UNIT 01	N/A	______
	A/C UNIT 02	N/A	______
	A/C UNIT 03	45%	______
	A/C UNIT 04	35%	______
8.6	CALCULATE AVERAGE A/C UNIT NO. 3 A/C UNIT NO. 4 (% UNLOADED 45 + % UNLOADED 35) / 2	= 40 TRAIN AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY	______ Perform Step 7 Cue VERIFIED
8.7	COMPARE OUTSIDE TEMP (STEP 8.3) AND AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY (STEP 8.6) TO CURVE (FIGURE 1)	OPERATION ABOVE/BELOW CURVE	______
	ACCEPTANCE CRITERIA SAT IF OPERATION IS ABOVE CURVE	SAT/UNSAT	______

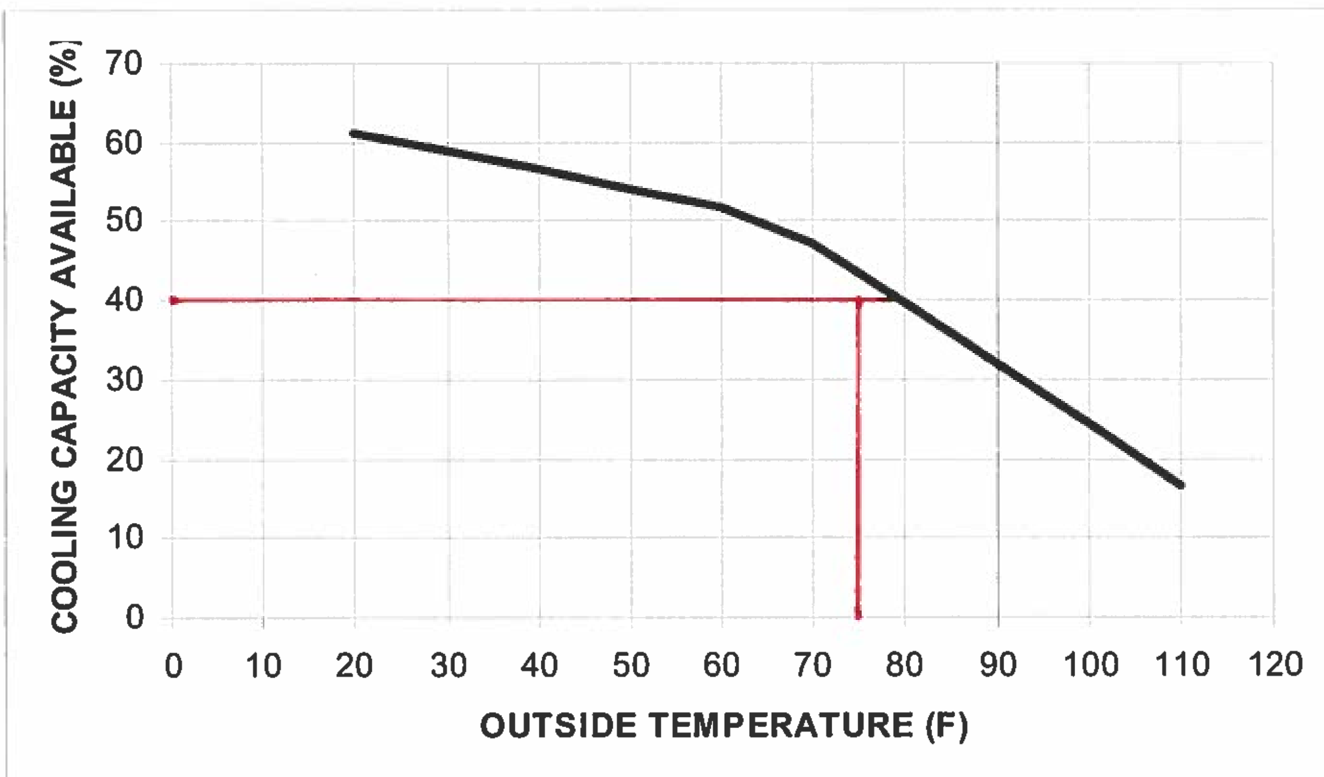
CR A/C SYSTEM DATA SHEET

FIGURE 1

OUTSIDE TEMPERATURE	PERCENT UNLOADED
	16.7
110	24.3
100	32.0
90	39.6
80	47.2
70	51.7
60	54.1
50	56.5
40	58.9
30	61.3
20	

CONTROL ROOM HVAC MINIMUM REQUIRED AVAILABILITY

THE UNLOADED COMBINED AVERAGE OF THE TWO 50% CONTROL ROOM HVAC UNITS MUST BE ABOVE THE CURVE REPRESENTED BELOW:



CR A/C SYSTEM DATA SHEET

COMMENTS/DISCREPANCIES:______________________________

CORRECTIVE ACTIONS:______________________________

PERFORMED BY:______________________________DATE:____________
SIGNATURE

REVIEWED BY:______________________________DATE:____________
OPERATIONS MANAGEMENT

CPNPP 2017 NRC ADMIN JPM RA3 Key

Facility: CPNPP JPM # NRC RA4 Task # BA1402 K/A # 2.3.4 3.2 / 3.7

Title: Determine Escorted Radiation Worker Allowable Dose

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Two pump experts have been brought onsite to assess the status of a damaged Centrifugal Charging Pump that has been repaired
- Plant management has requested that you escort and coordinate the assessment with the pump experts
- The pump experts have NOT been authorized for any DOSE beyond the normal Administrative Limits for an Escorted Radiation Worker
- The assessment is anticipated to take 2 hours
- The general dose rate in the area is 70 mrem / hour but can be reduced to 20 mrem / hour if lead shielding is installed
- Escorted Radiation Worker ‘A’ is a 40 year-old male that has received 250 mrem this year
- Escorted Radiation Worker ‘B’ is a 29 year-old female that has declared her pregnancy to Radiation Protection. She has received 5 mrem this year

Initiating Cue: The Shift Manager directs you to PERFORM the following:

- DETERMINE if Escorted Radiation Worker ‘A’ can perform the assessment without shielding
  - Escorted Radiation Worker ‘A’ ____________ perform the assessment without shielding
- DETERMINE if Escorted Radiation Worker ‘B’ can perform the assessment without shielding
  - Escorted Radiation Worker ‘B’ ____________ perform the assessment without shielding
- DETERMINE if Escorted Radiation Worker ‘A’ can perform the assessment with shielding and without an exposure extension.
  - Escorted Radiation Worker ‘A’ ____________ perform the assessment with shielding and without an exposure extension
- DETERMINE if Escorted Radiation Worker ‘B’ can perform the assessment with shielding and without an exposure extension
  - Escorted Radiation Worker ‘B’ ____________ perform the assessment with shielding and without an exposure extension

Task Standard: DETERMINED that both Escorted Radiation Workers would exceed their administrative limits without shielding. DETERMINED that Escorted Radiation Workers A and B could perform the assessment with shielding.

Ref. Materials: STA-655, Exposure Monitoring Program, Rev. 22.
STA-656, Radiation Work Control, Rev. 22.

Validation Time: 15 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ____ Date: ______________

CLASSROOM SETUP

EXAMINER:

PROVIDE the examinee with a copy of:

- **STA-655, Exposure Monitoring Program (Procedure 1).**
- **STA-656, Radiation Work Control (Procedure 2).**

√ - Check Mark Denotes Critical Step

START TIME:	

Perform Step: 1√	DETERMINE if Escorted Radiation Worker A can perform the assessment without shielding.
Standard:	DETERMINED total dose for Escorted Radiation Worker A would be 70 mrem x 2 hours = 140 mrem. 140 mrem is greater than 100 mrem Administrative Limit. Escorted Radiation Worker A cannot perform the assessment without shielding.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 2√	DETERMINE if Escorted Radiation Worker B can perform the assessment without shielding.
Standard:	DETERMINED total dose for Escorted Radiation Worker B would be 70 mrem x 2 hours = 140 mrem. 140 mrem is greater than 50 mrem Administrative Limit. Escorted Radiation Worker B cannot perform the assessment without shielding.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 3	DETERMINE if Escorted Radiation Worker A can perform the assessment with shielding and without an exposure extension.
Standard:	DETERMINED total dose for Escorted Radiation Worker A would be 20 mrem x 2 hours = 40 mrem. 40 mrem is less than 100 mrem Administrative Limit. Escorted Radiation Worker A can perform the assessment with shielding.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 4√	DETERMINE if Escorted Radiation Worker B can perform the assessment with shielding and without an exposure extension.
Standard:	DETERMINED total dose for Escorted Radiation Worker B would be 20 mrem x 2 hours = 40 mrem. 40 mrem + 5 mrem is less than 50 mrem Administrative Limit. Escorted Radiation Worker B can perform the assessment with shielding.
<u>Terminating Cue:</u>	**This JPM is complete.**
Comment:	**SAT** ☐ **UNSAT** ☐

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Two pump experts have been brought onsite to assess the status of a damaged Centrifugal Charging Pump that has been repaired**
- **Plant management has requested that you escort and coordinate the assessment with the pump experts**
- **The pump experts have NOT been authorized for any DOSE beyond the normal Administrative Limits for an Escorted Radiation Worker**
- **The assessment is anticipated to take 2 hours**
- **The general dose rate in the area is 70 mrem / hour but can be reduced to 20 mrem / hour if lead shielding is installed**
- **Escorted Radiation Worker 'A' is a 40 year-old male that has received 250 mrem this year**
- **Escorted Radiation Worker 'B' is a 29 year-old female that has declared her pregnancy to Radiation Protection. She has received 5 mrem this year**

Initiating Cue: **The Shift Manager directs you to PERFORM the following:**

- **DETERMINE if Escorted Radiation Worker 'A' can perform the assessment without shielding**
  - **Escorted Radiation Worker 'A' ____________ perform the assessment without shielding**
- **DETERMINE if Escorted Radiation Worker 'B' can perform the assessment without shielding**
  - **Escorted Radiation Worker 'B' ____________ perform the assessment without shielding**
- **DETERMINE if Escorted Radiation Worker 'A' can perform the assessment with shielding and without an exposure extension.**
  - **Escorted Radiation Worker 'A' ____________ perform the assessment with shielding and without an exposure extension**
- **DETERMINE if Escorted Radiation Worker 'B' can perform the assessment with shielding and without an exposure extension**
  - **Escorted Radiation Worker 'B' ____________ perform the assessment with shielding and without an exposure extension**

COMANCHE PEAK NUCLEAR POWER PLANT

STATION ADMINISTRATION

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS_________________/__________LATEST PCN/EFFECTIVE DATE____________/______________

LEVEL OF USE:
INFORMATION USE

QUALITY-RELATED

EXPOSURE MONITORING PROGRAM

PROCEDURE NO. STA-655

REVISION NO. 22

SORC MEETING NO.: 16-020 **DATE:** 12/07/2016

EFFECTIVE DATE: 12/27/2016

PREPARED BY (Print): John Lamons EXT: 6261

TECHNICAL REVIEW BY (Print): Michael Macho EXT: 5698

APPROVED BY: *John Dreyfuss* DATE: 12/13/2016

PLANT MANAGER

1.0 PURPOSE

The purpose of this procedure is to describe the requirements for the Exposure Monitoring Program. The Exposure Monitoring Program specifies the dosimetry requirements associated with the monitoring of occupational exposures to ionizing radiation at CPNPP.

1.1 The following do not require SORC review when being modified and issued per STA-202:

- STA-655-1, Cumulative Occupational Dose History (or equivalent)
- STA-655-3, Exposure Extension Authorization
- STA-655-4, NRC/INPO Unfettered Access Form
- STA-655-5, Bioassay Analysis Refusal
- STA-655-6, Bioassay Analysis Waiver and Release of Claims
- STA-655-7, Training Extension Request
- STA-655-8, DLR Issue Request
- STA-655-9, Medical Treatment Evaluation
- STA-655-10, Declared Radiation Worker Agreement
- STA-655-11, Planned Special Exposure
- STA-655-12, Statement of Unavailable Occupational Radiation Dose Records

2.0 APPLICABILITY

This procedure is applicable to all personnel who require access to radiologically controlled areas at CPNPP. In addition, Section 6.12, of this procedure “Medical Treatment” is applicable to all personnel onsite at CPNPP.

3.0 REFERENCES

3.1 EPP-305, Emergency Exposure Guidelines and Personnel Dosimetry

3.2 RPI-105, Exposure Records

3.3 STA-302, Station Records

3.4 STA-501, Nonroutine Reporting

3.5 STA-502, Routine Reporting

3.6 STA-656, Radiation Work Control

3.7 STA-657, ALARA Job Planning - Debriefing

3.8 TRA-102, Radiation Worker Training

3.9 10CFR19, Notices, Instructions, and Reports to Workers; Inspections

3.10 10CFR20, Standards for Protection Against Radiation

3.11 ANI/MAELU Information Bulletin 80-1A, Nuclear Liability Insurance Records Retention

3.12 INPO 95-008, Guidelines for Radiological Protection at Nuclear Power Stations

3.13 NRC Regulatory Guide 1.16, Reporting of Operating Information-Appendix A Technical

3.14 NRC Regulatory Guide 8.13, Instruction Concerning Prenatal Radiation Exposure

3.15 NRC Regulatory Guide 8.36, Radiation Dose to Embryo/Fetus

3.16 NCRP 91, Recommendations on Limits for Exposure to Ionizing Radiation

3.17 Supreme Court Opinion, No. 89-1215, in review of United Auto Workers, et.al vs. Johnson Controls, Inc.

3.18 EVAL-2006-631, Technical Evaluation for Detection Level by Qualitative Whole Body Counters at CPNPP

3.19 EV-CR-2013-005883-1, Evaluation of GEM-5 for use as Passive Whole Body Counter

3.20 NEI Efficiency Bulletin 16-26c, Implement Common NANTeL Radiation Worker Training

3.21 TE-2016-008174, Passive Monitoring in lieu of Quantitative Whole-body Counting

4.0 DEFINITIONS/ACRONYMS

4.1 Committed Dose Equivalent (CDE) – The dose equivalent to organs or tissues of reference that will be received from an intake of radioactive material by an individual during the 50-year period following the intake.

4.2 Committed Effective Dose Equivalent (CEDE) – The sum of the products of the weighing factors applicable to each of the body organs or tissues that are irradiated and the committed dose equivalent to these organs or tissues.

4.3 Contract Personnel – Those individuals who are not Luminant employees.

4.4 Declared Radiation Worker – A female Radiation Worker who has voluntarily informed her employer, in writing, of her pregnancy and estimated date of conception. Also applies to Escorted Radiation Workers who choose to declare their pregnancy.

4.5 Deep Dose Equivalent (DDE) – The dose equivalent to the (external) whole body at a tissue depth of 1000 mg/cm².

4.6 Dosimeter of Legal Record (DLR) – A dosimeter assigned to be worn by a single individual for a period of time, usually a thermo luminescent dosimeter.

4.7 Effective Dose Equivalent (EDEX) (H_E) – The sum of the products of the dose equivalent to the organ or tissue (H_T) and the weighting (W_T) applicable to each of the body organs or tissues that are irradiated ($H_E = \sum W_T H_T$).

4.8 Escorted Radiation Worker – An individual who is not a qualified Radiation Worker and requires a qualified escort to gain access to CPNPP radiologically controlled area(s) to perform work related to their employment.

4.9 Extremity – Hand, elbow, arm below the elbow, foot, knee and leg below the knee.

4.10 Eye Dose Equivalent (LDE) – External exposure of the lens of the eye and is taken as the dose equivalent at a tissue depth of 300 mg/cm².

4.11 Final Occupational Exposure Report – An exposure report (NRC Form 5, equivalent) that is based on DLR readings or official dose calculations and provided to radiation workers. The report should be signed by a representative of the issuing company.

4.12 Member of the Public – An individual who is not assigned duties related to employment which may potentially involve radiation and/or radioactive material. Dose received by a member of the public cannot be permitted to exceed the public dose limit, even if the individual is receiving that dose while in a restricted area.

4.13 Monitoring – Use of a dosimeter of legal record (DLR) to quantify dose.

4.14 National Voluntary Laboratory Accreditation Program (NVLAP) – A National Institute of Standards and Technology program whose function is to accredit public and private dosimeter processors.

4.15 Occupational Dose – The dose received by an individual in the course of employment in which the individual's assigned duties involve exposure to radiation and/or to radioactive material from licensed or unlicensed sources of radiation, whether in the possession of the licensee or other person. Occupational dose does not include dose received from background radiation, as a patient from medical practices, from voluntary participation in medical research, or as a member of the public.

4.16 Official Estimate – A report of estimated total effective dose equivalent for a radiation worker. These reports are normally identified by the words "interim report" or "estimate". The report should be signed by a representative of the issuing company.

4.17 Personnel Contamination Monitors (PCM) – Contamination monitors which in addition to identifying external contamination may be utilized for passive internal monitoring and the performance of qualitative whole body counting.

4.18 Planned Special Exposures – An infrequent exposure to radiation, separate from and in addition to, the annual dose limit; and that, if not provided for, would create a severe handicap to the plant's operation.

4.19 Public Dose – The dose received by a member of the public from exposure to radiation and/or radioactive material released by a licensee or to any other source of radiation under the control of a licensee. It does not include occupational dose or doses received from background radiation, as a patient from medical practices, or from voluntary participation in medical research programs.

4.20 Qualitative Whole Body Count – An in-vivo measurement performed with a personnel contamination monitor as a screening process to identify the presence of radioactive material internally.

4.21 Quantitative Whole Body Count – An in-vivo measurement performed with a Stand-up whole body counter which provides isotopic identification and quantification of radioactive material for dose analysis.

4.22 Radiation Worker – An individual who may receive occupational dose and who is qualified for unescorted access to CPNPP radiologically controlled area(s). Exposures to radiation workers should be determined by DLR and shall be reportable to the individual and to the NRC.

4.23 Radiologically Controlled Area (RCA) – Any area where access is controlled by the licensee for the purpose of protection of individuals from exposure to radiation and radioactive materials.

4.24 Self-Reading Dosimeter (SRD) – A device used to determine estimated dose. Except in unusual circumstances when record dose is required and DLR data is unavailable all data determined by an SRD should be considered unofficial and/or estimated dose.

4.25 Skin of the whole body – The skin covering all areas of the whole body, as defined for whole body and is taken as the dose equivalent at a tissue depth of 7 mg/cm^2.

4.26 Termination – For Luminant and contract employees, termination is the end of the employment at CPNPP, or the transfer of an employee to a department or location where radiologically controlled area access is no longer required.

4.27 Total Effective Dose Equivalent (TEDE) – The sum of the effective dose equivalent (for external exposures) and the committed effective dose equivalent.

4.28 Total Organ Dose Equivalent (TODE) – The sum of the deep dose equivalent (for the entire monitoring period) and committed dose equivalent recorded for the maximally exposed organ.

4.29 Whole body – For purposes of external exposure, head and trunk (including male gonads), arms above the elbow, or legs above the knee.

5.0 RESPONSIBILITIES

5.1 The Plant Manager is responsible for:

5.1.1 Approval of Total Effective Dose Equivalent Administrative Exposure Level extensions above 4000 mrem in one year.

5.1.2 Maintaining the Prenatal Exposure Policy as specified by this procedure.

5.1.3 Approval for all planned special exposures (PSE).

5.2 Radiation Protection Manager is responsible for:

5.2.1 Developing and implementing the exposure monitoring program for Radiation Workers at CPNPP.

5.2.2 Implementing the objectives of the Prenatal Exposure Policy as specified by this procedure.

5.2.3 Approval of Total Effective Dose Equivalent exposure extensions up to and including 4000 mrem in one year.

5.2.4 Utilize a National Voluntary Laboratory Accreditation Program accredited vendor for DLR processing.

5.2.5 Maintaining this procedure current.

5.3 Radiation Protection Supervisor is responsible for:

5.3.1 Ensuring that personnel exposure and dosimetry processing records are maintained in accordance with the applicable procedures and regulations.

5.3.2 Development and maintenance of Radiation Protection Instructions required to implement the Exposure Monitoring Program.

5.4 Chemistry Manager is responsible for:

5.4.1 Notifying the Radiation Protection Manager if reactor coolant tritium levels exceed 10 µCi/cc.

5.4.2 Providing reactor coolant tritium levels, as requested by Radiation Protection. Following are the tritium levels Radiation Protection is interested in:

- Divers in pools of water with tritium concentrations greater than or equal to 0.01 µCi/cc.
- Workers who routinely sample, and may be sprayed with, or otherwise come in contact with, water with tritium concentrations greater than or equal to 0.01 µCi/cc.

5.5 Station Supervisors are responsible for:

5.5.1 Identifying personnel under their direction who should be designated as Radiation Workers. The supervisor should ensure that the number of Radiation Workers in their area is kept to a minimum.

5.5.2 Ensuring that Radiation Workers under their direction maintain their Radiation Worker training qualifications current.

5.5.3 Initiating STA-655-3 to request exposure extensions when necessary.

5.5.4 Informing Radiation Protection when an employee has declared her pregnancy.

5.5.5 Managing the exposure of Declared Radiation Workers within the limits specified by this procedure.

5.5.6 Requesting additional training from the Training Department or Radiation Protection, as necessary.

5.5.7 Ensure that Radiation Workers under their direction notify Radiation Protection upon transfer to another department.

5.6 Radiation Workers are responsible for:

5.6.1 Ensuring that ALARA considerations are utilized in their work activities.

5.6.2 Remaining cognizant of their current exposure and ensuring they do not exceed the exposure levels as set forth by CPNPP.

5.6.3 Providing documentation of all current year occupational radiation exposure from other facilities if they have been monitored.

5.6.4 Maintaining an updated STA-655-8 on file with Radiation Protection Dosimetry.

5.6.5 Contacting Department Supervisor and Radiation Protection Dosimetry upon start/end of declaration of pregnancy.

5.6.6 Contacting Radiation Protection Dosimetry after visiting another facility where they were monitored for radiation exposure and complete any necessary documentation for that radiation exposure at the other facility.

5.6.7 Participating in the whole body counting procedures as required by Radiation Protection.

5.6.8 Notifying Radiation Protection if receiving occupational exposure due to work for another licensee while employed at CPNPP.

5.6.9 All Radiation Workers shall complete the training in accordance with TRA-102 covering the Prenatal Exposure Policy.
[NRC Regulatory Guide 8.13][CR-2005-002040]

5.6.10 Adhering to the Dosimetry guidelines listed in Attachment 8.C.

5.6.11 Notifying Radiation Protection Dosimetry of name change or changes to Employer (Company).

5.6.12 Notifying Radiation Protection if they do not hear the SRD speaker check and observe the vibration testing when logging into the RCA computer system.

5.7 Escorted Radiation Workers are responsible for:

5.7.1 Completing Section I of STA-656-3 to request Escorted Radiation Worker status, in accordance with STA-656.

5.7.2 Female Escorted Radiation Workers shall complete training covering the Prenatal Exposure Policy upon declaration of pregnancy.
[NRC Regulatory Guide 8.13]

5.8 All Personnel at CPNPP are responsible for:

5.8.1 Notifying Radiation Protection if medical treatment involving radioactive material will be received. Workers are not required to report medical X-rays.

6.0 INSTRUCTIONS

6.1 Requirements for Exposure Monitoring

CAUTION: No individuals should enter an RCA unless they are eighteen years of age or older.

6.1.1 Radiation Workers

6.1.1.1 The immediate supervisor or contract coordinator should ensure the employee's job function requires access to radiologically controlled areas.

[C] 6.1.1.2 The employee shall complete Radiation Worker Training (RWT) and receive an initial whole body count. **[00800][01806]**

6.1.1.3 The employee should provide copies of all exposure records from other facilities at which monitoring was provided for the current year.

6.1.1.4 The employee should complete STA-655-8 for Radiation Protection Dosimetry.

6.1.1.5 NRC Form 4s which are countersigned by a licensee or the current employer and NRC Form 5s are acceptable documentation of previous occupational exposure.

6.1.1.6 If the employee does not have all previous exposure records for the current year, the individual should sign an authorization to release previous exposure records to CPNPP.

6.1.1.7 If exposure records for the current year cannot be obtained, the individual may initiate STA-655-12 to document his/her year-to-date exposure to be used as a dose of record at CPNPP.

6.1.1.8 Upon receipt of all final exposure records for the current year, the individual should report to Radiation Protection Dosimetry to authenticate the exposure records.

6.1.2 Escorted Radiation Workers

6.1.2.1 Escorted Radiation Workers should be provided access to the Radiologically Controlled Area(s) in accordance with STA-656.

6.1.3 NRC/INPO Personnel

6.1.3.1 NRC/INPO personnel should provide documentation of current Radiation Worker Training. The documentation may include, but is not limited to the following:

- A letter from the NRC certifying individual's qualifications.
- Verification from the Luminant Nuclear Training Department certifying the individual's qualifications.
- Documentation of successful completion of an INPO accredited Radiation Worker Training class from another facility/plant.

6.1.3.2 NRC/INPO personnel may complete STA-655-4 in lieu of STA-655-8.

1. Have the individual step into a PM-7/GEM-5 and document on the STA-655-8 or STA-655-4 as applicable, that no alarm occurred. If an alarm occurs on the PM-7/GEM-5 a quantitative whole body is required prior to entry into the RCA.
2. If the PM-7/GEM-5 is unavailable, a quantitative WBC may be performed. NA the applicable sections of the form.
3. NRC personnel issued a DLR under STA-655-4 should be limited to 500 mrem per year at this site. |

6.2 Exposure Limits

6.2.1 Administrative exposure levels and Federal exposure limits for occupational exposure to ionizing radiation are provided in Attachments 8.A and 8.B, respectively.

[C] 6.2.2 Exposure estimates for gamma radiation exposure(s) may be evaluated by methods such as pocket ionization chambers, SRDs or survey data if other methods are unavailable. |
[03942]

6.2.3 Based on estimates provided on STA-655-8 for the Total Effective Dose Equivalent (TEDE), the RP Supervisor may initiate lower TEDE Administrative levels. The individual's supervisor should be notified of the reduced TEDE levels.

[C] 6.3 Declaration of Pregnancy and Exposure Limits
[26820]

[C] 6.3.1 Female Radiation Workers or Female Escorted Radiation Workers may elect to limit exposure to their embryo/fetus by formally declaring their pregnancy in writing. This option allows the employee to pursue continued active employment at CPNPP while providing means to protect the embryo/fetus in accordance with USNRC Regulatory Guide 8.13 and NCRP-91 guidance.
[23006]

6.3.2 Upon declaration of pregnancy, reduced exposure limits shall be implemented to minimize risk to the embryo/fetus from ionizing radiation. The reduced exposure limits only applies for the duration of the pregnancy and does not include periods directly before or after pregnancy.

6.3.3 It is the sole responsibility of the female Radiation Worker or Escorted Radiation Worker to decide whether or not to limit her occupational exposure.

6.3.3.1 A female Radiation Worker or Escorted Radiation Worker requesting a formal declaration of pregnancy should do so by notifying her employer or escort and Radiation Protection Dosimetry by completing STA-655-10.

6.3.3.2 Attachment 8.D, Acknowledgment of Training and Female Radiation Exposure Declaration, should be provided to the individual as part of the Declaration process.

6.3.3.3 The female should meet with RP Supervision to discuss limits and concerns.

6.3.4 A female Radiation Worker or Escorted Radiation Worker has the right to rescind her declaration at any time by informing her Supervisor or escort and Radiation Protection Dosimetry by completing STA-655-10.

[C] 6.3.5 Luminant, CPNPP, shall provide training consistent with Regulatory Guide 8.13 and other applicable regulations and guidelines to employees in order for them to make informed decisions regarding the potential radiation effects on the embryo/fetus. Radiation Protection/Training is available if employees have any additional questions.
[23006]

6.3.6 Luminant, CPNPP, is taking all practical measures to assist females in reducing potential fetal radiation exposure within the stated guidelines. However, Declared Radiation Workers or Declared Escorted Radiation Workers are responsible for maintaining their exposure within the limits set forth by this procedure.

6.3.7 Administrative exposure levels for the embryo/fetus of a Declared Radiation Worker or Declared Escorted Radiation Worker are defined in Attachment 8.A.

6.3.8 Upon delivery (birth), the Declared Radiation Worker should initiate STA-655-10 to record the delivery date and inform Radiation Protection Dosimetry, in order to reinstate normal administrative exposure levels. The normal administrative exposure level will be automatically reinstated 1 year after declaration.

6.3.9 All estimates of the dose to the embryo/fetus of a Declared Radiation Worker shall be made in accordance with NRC Regulatory Guide 8.36.

6.4 <u>Administrative Exposure Level Extensions</u>

6.4.1 CPNPP Administrative Levels for exposure to ionizing radiation may be extended provided the following conditions are met:

6.4.1.1 The individual has a current STA-655-8 on file.

6.4.1.2 A current STA-655-1 for any extension greater than 4000 mrem in a year.

6.4.1.3 The current assigned DLR may be processed as determined by Radiation Protection. |

6.4.2 The total occupational dose shall not exceed any NRC limit as specified in Attachment 8.B.

6.4.3 Administrative Exposure Level Extension Process

6.4.3.1 To obtain an extension up to and including 4000 mrem, the individual's immediate supervisor should complete Part 1 of STA-655-3 and provide justification as to the necessity of exceeding the administrative level.

6.4.3.2 The immediate supervisor should forward STA-655-3 to Radiation Protection Dosimetry.

6.4.3.3 The Plant Manager should approve any extension above 4000 mrem in one year.

6.4.3.4 The Radiation Protection Manager should approve any extensions up to and including, 4000 mrem in one year.

6.4.3.5 Radiation Protection Dosimetry should update the Radiation Protection Computer System with the new limits and file the extension in the individual's exposure record.

[C] 6.4.4 Under declared emergency conditions, Administrative Levels do not apply. The federal limits in 10CFR20 are applicable. Emergency exposure extensions in excess of the applicable federal limits and DLR issuance shall be processed in accordance with EPP-305. **[06380]**

6.5 <u>Planned Special Exposures</u>

6.5.1 A Planned Special Exposure (PSE) may be requested for an individual or a crew to complete a vital task for the continued operation of the plant or to complete a critical job.

6.5.2 A PSE shall not be utilized as a means for extending dose limits.

6.5.3 A PSE shall only be used for exceptional situations of which their appropriateness may be reviewed by the NRC. Following are some examples of exceptional situations:

- Not enough skilled worker(s) are available for a critical path job.
- Shielding is not practical for reducing exposures.
- Collective dose to personnel may be reduced.

6.5.4 Once an exposure is authorized as a PSE, it cannot later be treated as a routine occupational exposure, even if the exposure was less than anticipated; and therefore all of the unique limitations, reporting, and record keeping requirements apply.

6.5.5 Radiation Protection should initiate STA-655-11 by completing Section I, providing justification for the exceptional situation.

6.5.6 Radiation Protection shall determine prior dose.

6.5.6.1 Dosimetry shall process DLRs and obtain all previous doses due to other PSEs and all doses in excess of the routine occupational limits for each individual.

6.5.6.2 Doses received in excess of routine occupational dose limits, including accidents and emergencies, shall also be subtracted from the limits for PSEs.

6.5.6.3 If complete lifetime records (STA-655-1) are not available, then the individual shall not be eligible for the PSE.

6.5.6.4 Dosimetry Records shall sum the outstanding dose (Section 6.5.6.1) for each individual and record the final result on STA-655-11.

6.5.6.5 The PSE may be approved if the sum of the outstanding dose from Section 6.5.6.2 above and the exposure estimate of the PSE does not exceed the dose limits in Attachment 8.A for PSEs.

6.5.6.6 Radiation Protection should sign and date the final result.

6.5.6.7 Radiation Protection should forward STA-655-11 to the Plant Manager.

6.5.7 Obtain approval for the PSE from the Plant Manager and the individual's employer if the employer is not Luminant.

6.5.8 A radiologically significant briefing should be performed for the individual(s) involved. Ensure the following are documented:

- Informed of the PURPOSE of the planned operation.
- Informed of the estimated doses and potential risks and other conditions involved in performing the task.
- Instructed in measures to be taken to keep the dose ALARA while considering other risks which may be present.

6.5.9 Attach the radiologically significant ALARA briefing documentation to the PSE.

6.5.10 A written report notifying the Administrator of the NRC Regional Office of the PSE shall be presented within 30 days, in accordance with STA-502.

6.6 Administrative Termination of Radiologically Controlled Area Access

Radiation Worker access to radiologically controlled areas may be terminated under any of the following conditions:

- Disregard or violation of radiological procedures or radiation work permits.
- Failure to complete whole body count requested by Radiation Protection.
- Failure to maintain the required training for access to radiologically controlled areas.

6.7 Visiting Other Sites or Leaving CPNPP for an Extended or Unknown Period of Time

6.7.1 When returning to CPNPP, personnel (Radiation Workers) should report to Radiation Protection Dosimetry to complete any documentation of any dose estimate (written or verbal) received at the other site. When final exposure records are provided to the individual, a copy should be forwarded to Radiation Protection Dosimetry.

6.8 Radiation Worker Termination

6.8.1 Radiation Workers terminating employment at CPNPP should report to Radiation Protection Dosimetry located in the Radiation and Industrial Safety Building (Bldg 3J7) to turn in their DLR and complete paperwork.

6.8.2 If a Radiation Worker terminates under adverse conditions and cannot out-process through Radiation Protection Dosimetry, the supervisor should notify the Radiation Protection Supervisor within 24 hours of the individual's termination.

6.9 Training Extension

6.9.1 Responsible Managers should not initiate STA-655-7, unless extenuating circumstances are associated with the failure to attend training within the specified time period.

6.9.2 The responsible manager should complete STA-655-7. The training extension should not exceed 30 days.

6.10 Dosimetry Program

6.10.1 Radiation Protection shall utilize a National Voluntary Laboratory Accreditation Program accredited vendor for DLR processing as required by 10CFR20.

[C] 6.10.2 A NVLAP accredited vendor is available for prompt processing of DLRs. **[10824]**

[C] 6.10.3 Dosimetry equipment such as multibadging and telemetry (alarming and integrating) devices are available for those assignments that require special dosimetry.
[00791]

[C] 6.10.4 Station and support personnel or visitors who enter radiologically controlled areas at CPNPP are monitored for external radiation exposure using DLRs or SRDs. Issuance of DLRs or SRDs, DLR processing and dose determination are performed in accordance with approved station procedures.
[00297]

6.10.5 All current, routinely used SRDs are equipped with Vibrating alarm, 85 dB audible alarm, forward flashing ultra LED, and a trio of Red Green or Blue alarm LEDs. Contact Radiation Protection if the SRD fails the speaker check and vibrating alarm when activating the SRD prior to entry into the RCA.

6.11 Whole Body Counting Program

6.11.1 The bioassay and whole body counting programs should be implemented in accordance with Radiation Protection Instructions.

6.11.2 Routine Measurements include baseline measurements, periodic measurements, and termination measurements. These measurements should be conducted to confirm that appropriate controls exists and to assess dose for personnel granted permission to enter a RCA.

6.11.2.1 An initial qualitative WBC is done to screen for the presence of internal radioactive material. A quantitative WBC should be performed to provide isotopic identification and quantification of the internal radioactive material as justified by a positive qualitative WBC.

6.11.3 Exposure control whole body counts and bioassays verify that the practices and procedures used at CPNPP for controlling and limiting internal exposure and have been reviewed for ALARA considerations.

6.11.3.1 Administrative intake levels are not expressed in Derived Air Concentration hours (DAC-hours) per seven consecutive days at CPNPP. Whole Body Counts (in-vivo) and in-vitro samples are taken as necessary to monitor and document internal dose.
[ACTN-MAN-2007-002722-05]

6.11.3.2 A Qualitative Whole Body Count is performed as personnel exit the RCA and protective area. The monitors detect to a level of less than .02% of an ALI for the predominant isotopes of concern at CPNPP.
[EVAL-2006-000631][ACTN-MAN-2007-002722-05]
[CR-2013-005883][EV-TR-2016-008174]

6.11.4 Personnel refusing to participate in the whole body count or bioassay program should have their radiologically controlled area access revoked.

6.11.4.1 Reinstatement of access to the Radiologically Controlled Area requires the approval of the Radiation Protection Manager.

6.11.4.2 STA-655-5 should be used to document this process.

6.11.5 All radioactive sources used for calibration of bioassay measurement equipment shall be traceable to the National Institute of Standards and Technology.
[ONE-97-000753]

6.12 Medical Treatment

NOTE:	This section is applicable to all personnel onsite at CPNPP.

6.12.1 Personnel should inform Radiation Protection if medical treatment involving radioactive material is being received or has recently been received. The individual should initiate STA-655-9 and provide to Radiation Protection, who will determine the impact of the treatment on the exposure monitoring program and the radiological controls of the plant's waste streams. Restrictions should be commensurate with the level and type of medical treatment.

6.12.1.1 If the medical treatment impacts the exposure monitoring program then Radiation Protection may restrict the individual from the RCA.

6.12.1.2 All decisions regarding any restrictions will be handled on a case-by-case basis.

6.12.1.3 Radiation Protection should maintain the STA-655-9 in a file until the individual can pass through the portal monitors or for an appropriate amount of time dependent on the isotopes administered. The form should be dispositioned in accordance with STA-302.

6.13 Reports

6.13.1 Current Total Effective Dose Equivalent (TEDE) exposure is displayed by the RP Computer System for individual Radiation Workers upon entry and exit from the RCA. A hard copy report of this data may be generated upon request.

[C] 6.13.2 Current Total Effective Dose Equivalent (TEDE) exposure reports for Radiation Workers should be sent to supervisors and/or managers upon request. These reports may vary in frequency based on plant conditions or as requested.
[00820]

6.13.3 Any Radiation Worker or Escorted Radiation Worker may request to be furnished with reports showing his/her exposure to radiation or radioactive materials in accordance with 10CFR19.

6.13.4 When a request is made from another utility or agency to use whole body counting or bioassay services at CPNPP for any individual not assigned to or planning to enter CPNPP RCA, STA-655-6 should be completed.

6.13.5 INPO's Director, Radiological Protection and Emergency Preparedness Division shall be notified at (770) 644-8000 by Radiation Protection of each instance in which an individual receives more than 5.0 rem (TEDE) in a calendar year. "Non-Routine Reporting" shall be generated in accordance with STA-501.

6.13.6 Exposure reports of TEDE (NRC Form 5) for terminated Radiation Workers who are monitored by DLR shall be submitted to the individual in accordance with 10CFR19.

6.13.7 An Occupational Exposure Report of TEDE (RPI-105-6) containing the PSE total effective dose equivalent shall be forwarded to the respective individual(s) within 30 days of the PSE but no later than when the PSE report is transmitted to the NRC.

6.13.8 The dose to an embryo/fetus shall be maintained with the records of dose for the Declared Radiation Worker or Declared Escorted Radiation Worker and available only upon request. The embryo/fetus dose report (NRC Form 5) is not included in the annual report to the NRC.

6.13.9 Annual 10CFR20.2206 exposure reports for all individuals for whom monitoring was provided shall be submitted to the NRC by means of hardcopy (RPI-105-6) or electronic media containing all the information required by NRC FORM 5, in accordance with STA-502.

6.13.10 Annual 10CFR19.13(b) exposure reports for all individuals for whom monitoring was provided shall be submitted to each respective individual, in accordance with STA-502.

1. A final Occupational Exposure Report for those individuals terminated during the year meets the requirement of Section 6.13.10 and 10CFR19.13(b).

7.0 FIGURES

None

8.0 ATTACHMENTS/FORMS

8.1 Attachments

8.1.1 Attachment 8.A, Administrative Exposure Levels

8.1.2 Attachment 8.B, NRC Exposure Limits

8.1.3 Attachment 8.C, Dosimetry Guidelines

8.1.4 Attachment 8.D, Acknowledgment of Training and Female Radiation Exposure Declaration

8.2 Forms

8.2.1 STA-655-1, Cumulative Occupational Dose History (or equivalent)

8.2.2 STA-655-3, Exposure Extension Authorization

8.2.3 STA-655-4, NRC/INPO Unfettered Access Form

8.2.4 STA-655-5, Bioassay Analysis Refusal

8.2.5 STA-655-6, Bioassay Analysis Waiver and Release of Claims

8.2.6 STA-655-7, Training Extension Request

8.2.7 STA-655-8, DLR Issue Request

8.2.8 STA-655-9, Medical Treatment Evaluation

8.2.9 STA-655-10, Declared Radiation Worker Agreement

8.2.10 STA-655-11, Planned Special Exposure

8.2.11 STA-655-12, Statement of Unavailable Occupational Radiation Dose Records

[C] 9.0 RECORDS

When completed, the following forms, reports, or other documents generated in response to this procedure shall be dispositioned in accordance with STA-302.
[06876]

9.1 STA-655-1, Cumulative Occupational Dose History (or equivalent)

9.2 STA-655-3, Exposure Extension Authorization

9.3 STA-655-4, NRC/INPO Unfettered Access Form

9.4 STA-655-5, Bioassay Analysis Refusal

9.5 STA-655-6, Bioassay Analysis Waiver and Release of Claims

9.6 STA-655-7, Training Extension Request

9.7 STA-655-8, DLR Issue Request

9.8 STA-655-9, Medical Treatment Evaluation

9.9 STA-655-10, Declared Radiation Worker Agreement

9.10 STA-655-11, Planned Special Exposure

9.11 STA-655-12, Statement of Unavailable Occupational Radiation Dose Records

ATTACHMENT 8.A
PAGE 1 OF 2

ADMINISTRATIVE EXPOSURE LEVELS

RADIATION WORKERS

PERIOD	CALCULATION	LEVEL
Annual	TEDE (Total Effective Dose Equivalent)	2000 mrem
Annual	Skin Dose	40 REM/year
Annual	Extremities	40 REM/year
Annual	Lens of the Eye	12 REM/year
Annual	Total Organ Dose	40 REM/year

PERIOD	EVENT	LEVEL
Annual	Planned Special Exposure (PSE)	4000 mrem
	NOT TO EXCEED:	
Lifetime	Planned Special Exposure (PSE)	Five times the annual dose limit.

ATTACHMENT 8.A
PAGE 2 OF 2

ADMINISTRATIVE EXPOSURE LEVELS

EMBRYO/FETUS OF DECLARED PREGNANT RADIATION WORKER

PERIOD	RECEPTOR	LEVEL
Gestation	Declared Radiation Worker **OR:** Declared Escorted Radiation Worker	450 mrem (Not to exceed 50mrem/month)

NOTE: **If the dose to the embryo/fetus is found to have exceeded 200 mrem by the time the woman declares pregnancy, then any additional dose should not exceed 50 mrem during the remainder of the pregnancy.**

NOTE: **Administrative Exposure Levels are based on SRD estimates.**

ESCORTED RADIATION WORKERS

PERIOD	CALCULATION	LEVEL
Monitoring Period	DDE (Deep Dose Equivalent) (with DLR)	100 mrem
	With appropriate authorization:	
Annual	DDE (Deep Dose Equivalent) (with DLR)	≤ 2000 mrem

MEMBER OF THE PUBLIC

PERIOD	CALCULATION	LEVEL
Quarter	DDE (Deep Dose Equivalent)	20 mrem

NOTE: **A Member of the Public is not allowed into a contaminated or airborne area and therefore a committed dose equivalent should not be calculated.**

NOTE: **Administrative Exposure Levels are based on SRD estimates.**

ATTACHMENT 8.B
PAGE 1 OF 2

NRC EXPOSURE LIMITS

RADIATION WORKERS

PERIOD	CALCULATION	LEVEL
Annual	TEDE (Total Effective Dose Equivalent)	5000 mrem
	OR	
Annual	TODE - (The SUM of Deep-Dose Equivalent and Committed Dose Equivalent to any individual organ or tissue other than the lens of the eye).	50,000 mrem

PERIOD	RECEPTOR	LEVEL
Annual	Lens of the Eye Dose Equivalent (LDE)	15,000 mrem
Annual	Shallow Dose Equivalent for the Skin (SDE_{WB})	50,000 mrem
Annual	Shallow Dose Equivalent for each Extremity (SDE_{ME})	50,000 mrem

PERIOD	EVENT	LEVEL
Annual	All Planned Special Exposures	5000 mrem
Lifetime	Planned Special Exposure (PSE)	Five times any annual dose limit.

ATTACHMENT 8.B
PAGE 2 OF 2

NRC EXPOSURE LIMITS

EMBRYO/FETUS OF A DECLARED PREGNANT RADIATION WORKER

PERIOD	RECEPTOR	LIMIT
Gestation	Embryo/Fetus	500 mrem

NOTE 1: If the dose to the embryo/fetus is greater than 450 mrem by the time the declaration is made, then the licensee is in compliance if the additional dose does not exceed 50 mrem during the remainder of the gestation period.

MEMBER OF THE PUBLIC

PERIOD	CALCULATION	LIMIT
Annual	TEDE (Total Effective Dose Equivalent)	100 mrem

ATTACHMENT 8.C
PAGE 1 OF 2

DOSIMETRY GUIDELINES

- Personnel entering the RCA should wear their dosimetry at all times. Unless otherwise instructed, dosimetry should be worn on the upper front part of the body between the head and waist.

  - When personnel are working inside electrical panels, personnel are to wear dosimetry inside their clothing. This is to accomplish both electrical safety and to ensure the workers are monitored. It is NOT acceptable to remove dosimetry and place to the side.

- Assigned DLRs should be kept in one of the following approved storage locations, unless otherwise approved by radiation protection;

  - 810 Hallway Storage Racks
  - Warehouse C Storage
  - Security Badge approved storage location

- SRDs or Pocket Ion Chambers (PIC) must be worn at approximately the same location (e.g., within a hand's width) as the DLR, however, they should not shield each other. SRDs should be worn with the clip closest to the body so the detector is not shielded. SRDs and DLRs should be worn with the beta/open window facing away from the body.

- Workers should read their SRDs or PICs periodically while in the RCA and more often in elevated dose rate areas to prevent an SRD Dose Alarm and to ensure that doses received are consistent with expectations. SRDs shall be read upon egress from an RCA and recorded. **[CR-2006-000864]**

- PIC's may be read by pointing them toward a light source and observing the position of the hairline indicator on the scale. PIC estimate should be recorded and zeroed prior to or when it reaches 75% of full scale.

- Special or additional dosimetry may be required as specified on the RWP for a given task.

- Exit the RCA immediately and report to Radiation Protection if dosimetry becomes lost, damaged, or you observe your PIC reading to be off scale or at 75% of full scale (e.g., 150 mR for a 200 mR range PIC). Report to Radiation Protection immediately if the preset dose alarm goes off on the SRD.

ATTACHMENT 8.C
PAGE 2 OF 2

DOSIMETRY GUIDELINES

- Questions pertaining to dosimetry should be directed to Radiation Protection Dosimetry.

- Inform Radiation Protection if medical treatment involving radiation (other than normal X-ray examinations) is being received. Radiation Protection will determine the required action, if any, which may include dose restrictions or restriction from the RCA or Protected Area.

- All current routine used SRDs are equipped with Vibrating alarm, 85 dB audible alarm, forward flashing ultra LED, and a trio of Red Green or Blue alarm LEDs. Contact Radiation Protection if the SRD fails the speaker check and vibrating alarm when activating the SRD prior to entry into the RCA.

ATTACHMENT 8.D
PAGE 1 OF 1

ACKNOWLEDGMENT OF TRAINING AND FEMALE RADIATION EXPOSURE DECLARATION

I understand that Luminant is obliged by applicable law to take the position that protection of the health of the unborn child is the immediate and direct responsibility of the prospective parent(s). While the medical profession and the Company can support the parent(s) in the exercise of this responsibility, the Company cannot assume it for the parent(s) without, according to the courts, simultaneously infringing upon individuals' rights. I also understand that policies which, as a rule, inhibit a woman's activities in the workplace on the basis of fetal protection concerns, are improper under the law of the United States, unless a woman voluntarily requests more protective dose limits be applied to her or in cases in which sex or pregnancy actually interferes with the employee's ability to perform the job.

I have received training from Luminant concerning the radiological hazards of employment in a nuclear power plant. I have also received training regarding the effects of radiation on an unborn child (such as mental retardation and birth size, childhood cancer, radiation-induced genetic effects, and the radio-sensitivity of the embryo/fetus.) I also received training regarding the matters discussed in NRC Regulatory Guide 8.13, entitled "Instruction Concerning Parental Radiation Exposure", Rev. 2, December, 1987. I have read the summary of STA-655 "Exposure Monitoring Program" which outlines the Company's prenatal exposure policy. This instruction was presented to me both orally and in written form.

I had the opportunity to ask questions concerning all aspects of the presentation and as a Radiation Worker I achieved a passing score on an examination covering the subject matter of NRC Regulatory Guide 8.13.

I understand that the National Council on Radiation Protection and Measurement has recommended a separate dose level of 500 mrem to the unborn child from occupational exposure of the expectant mother for the term of the pregnancy. I understand that limiting the dose to the embryo/fetus for the term of the pregnancy may result in lowering the occupational dose which I may receive. I understand that I must declare in writing, whether I wish to be considered a Declared Radiation Worker. As a Declared Radiation Worker I will be restricted to an administrative exposure level of 200 mrem for the entire gestation period, not to exceed 50 mrem per month. If I choose instead to be considered a Radiation Worker, my annual administrative exposure level will be based on Attachment 8.A.

COMANCHE PEAK NUCLEAR POWER PLANT

STATION ADMINISTRATION MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS_________________/__________LATEST PCN/EFFECTIVE DATE 1 / 01/10/2017

LEVEL OF USE:
INFORMATION USE

QUALITY-RELATED

RADIATION WORK CONTROL

PROCEDURE NO. STA-656

REVISION NO. 22

SORC MEETING NO.: 16-020 **DATE:** 12/07/2016

EFFECTIVE DATE: 12/27/2016

PREPARED BY (Print): Shari Mosty EXT: 5204

TECHNICAL REVIEW BY (Print): James Goodrich EXT: 5960

APPROVED BY: *John Dreyfuss* DATE: 12/13/2016

PLANT MANAGER

[C] 1.0 PURPOSE

The purpose of this procedure is to provide a method for the control of access to Radiologically Controlled Areas, provide exposure accountability and assure that radiological conditions are identified to Radiation Workers, Escorted Radiation Workers, and Members of the Public prior to access to the Radiologically Controlled Areas. **[07325]**

1.1 The following do not require SORC review when being modified and issued per STA-202:

- Attachment 8.C
- Attachment 8.D
- STA-656-2
- STA-656-3
- STA-656-4
- STA-656-5
- STA-656-6

2.0 APPLICABILITY

This procedure is applicable to all personnel entering Radiologically Controlled Areas.

3.0 REFERENCES

3.1 Comanche Peak, FSAR Section 12, Radiation Protection

3.2 EPP-116, Emergency Repair & Damage Control and Immediate Entries

3.3 RPI-516, Dose Determination

3.4 STA-302, Station Records

3.5 STA-653, Contamination Control Program

3.6 STA-655, Exposure Monitoring Program

3.7 STA-657, ALARA Job Planning/Debriefing

3.8 STA-902, Access to CPNPP Site Areas

3.9 CPNPP Technical Specification 6.12.1 (ITS 5.7.1)

3.10 SEC-120, Security Clearance Program

3.11 INPO Significant Operating Experience Report (SOER) 2001-1, Unplanned Radiation Exposures

3.12 NEI Efficiency Bulletin: 16-13, Perform Self-Briefs for Low Radiological Risk Activities

3.13 NEI Efficiency Bulletin: 16-26C, Implement Common NANTel Radiation Worker Training

4.0 DEFINITIONS/ACRONYMS

4.1 Access Point – An entry way into a radiologically controlled area which does not require the radiation worker to move, alter or adjust radiological postings.

4.2 Dose Margin – The amount of radiation exposure an individual may receive before reaching the most restrictive administrative level or federal limit.

4.3 Self-Reading Dosimeter – A device used to determine estimated dose. Except in unusual circumstances when record dose is required and DLR badge data is unavailable, all data determined by self-reading dosimetry should be considered unofficial and/or estimated dose. The Self-Reading dosimeter was previously defined as an electronic dosimeter.

4.4 Escorted Radiation Worker – An individual, who is not a qualified Radiation Worker that requires a qualified escort to gain access to CPNPP Radiologically Controlled Area(s) in order to perform work related to their employment.

4.5 General Access Permit (GAP) – A general radiation work permit issued to allow Radiologically Controlled Area entry for routine inspections, testing and equipment operation. General Access Permits are used only for areas where radiation hazards are known and not expected to change frequently or rapidly.

4.6 Member of the Public – An individual who is not assigned duties related to employment which may potentially involve radiation and/or radioactive material. Dose received by a member of the public cannot be permitted to exceed the public dose limit, even if the individual is receiving that dose while in a restricted area.

4.7 Monitoring – Use of a Dosimeter of Legal Record (DLR) badge to quantify dose.

4.8 Occupational Dose – The dose received by an individual in the course of employment in which the individual's assigned duties involve exposure to sources of radiation and/or to radioactive material from licensed or unlicensed sources of radiation, whether in the possession of the licensee or other person. Occupational dose does not include dose received from background radiation, as a patient from medical practices, from voluntary participation in medical research, or as a member of the public.

4.9 PADS – The Personnel Access Data System Computer used for in-processing of consenting transient workers at nuclear power plants.

4.10 Personnel Contamination Monitors (PCM) – Contamination monitors which in addition to identifying external contamination may be utilized for passive internal monitoring and performance of qualitative whole body counting.

4.11 Public Dose – The dose received by a member of the public from exposure to radiation and/or radioactive material released by a licensee or to any other source of radiation under the control of the licensee. This dose does not include occupational dose or doses received from background radiation, as a patient from medical practices, or from voluntary participation in medical research programs.

4.12 Qualitative Whole Body Count – An in-vivo measurement performed with a personnel contamination monitor as a screening process to identify the presence of radioactive material internally.

4.13 Quantitative Whole Body Count – An in-vivo measurement performed with the Chair or Stand-Up Whole Body Counter which provides isotopic identification and quantification of radioactive material for dose analysis.

4.14 Radiation Work Permit (RWP) – A document issued for a specific task, job, or series of tasks specifying the radiological precautions to be followed while conducting the particular activity. Radiation Work Permits are used to provide accurate exposure usage accounting for specific tasks.

4.15 Radiation Worker – An individual who may receive occupational dose and who is qualified for unescorted access to CPNPP Radiologically Controlled Area(s). Exposures to radiation workers should be determined by DLR badge and shall be reportable to the individual and to the NRC.

4.16 Radiation Worker RCA Card – A card used for self-verification that allows the radiation worker to review radiological information prior to accessing the RCA (e.g., Self - briefings, HRA briefings, self-reading dosimeter set-points, contamination levels, etc.).

4.17 Radiologically Controlled Area (RCA) – Any area where access is controlled by the licensee for the purposes of protection of individuals from exposure to radiation and radioactive materials.

4.18 Radiation Worker Self-Brief – A briefing documented on a RCA Card where radiation workers brief themselves on work area radiological conditions without having to interface directly with radiation protection personnel.
[CR-2016-003857]

4.19 RP Computer System – The computer system that is currently installed and used by Radiation Protection for various radiation protection related functions.

4.20 Work Process Computer System – This is the computer software program that is used as an aid to the administration, tracking and scheduling of maintenance, calibration, inspection, testing and approved modification activities.

5.0 RESPONSIBILITIES

5.1 Radiation Protection Manager

[C] 5.1.1 Responsible for providing Radiation Work and General Access Permits for activities performed in the RCA.
[00796][27374]

[C] 5.1.2 Responsible for ensuring that current radiological information is available for Radiation Work and General Access Permits.
[07325]

[C] 5.1.3 Responsible for supporting the Operations, Maintenance, and Engineering departments and provides radiation protection coverage for activities that involve exposure to radiation or radioactive material.
[01151]

5.1.4 Responsible for maintaining this procedure current.

5.2 Responsible Work Organization

5.2.1 Responsible for requesting Radiation Work and General Access Permits for activities in the RCA.

5.2.2 Responsible for performing and documenting radiological self-briefs for activities with low radiological risk. The RCA Briefing Cards will be used for documentation of briefings
[CR-2016-003857]

5.3 Director, Nuclear Training

5.3.1 Responsible for providing Radiation Worker Training to Radiation Workers.

5.4 Radiation Workers

5.4.1 Responsible for reading and following the appropriate GAP/RWP.

5.5 Members of the Public

5.5.1 Responsible for providing information for completion of STA-656-6.

5.5.2 Responsible for remaining with their escort at all times.

5.6 Escorted Radiation Workers

5.6.1 Responsible for providing information for completion of required data on STA-656-3, STA-655-8, and STA-655-10, if applicable.

5.6.2 Responsible for providing current year exposure estimate.

5.6.3 Responsible for remaining with their escort at all times.

5.7 Escorts

5.7.1 Responsible for fulfilling those responsibilities of the escort as discussed in STA-902.

5.7.2 Responsible for ensuring that the Escorted Radiation Worker/Member of the Public receives the proper dosimetry from RP prior to entering the RCA.

5.7.3 Responsible for adhering to posted areas in regard to the restriction placed on escorted radiation workers or member of the public.

6.0 INSTRUCTIONS

6.1 Prerequisites

6.1.1 Food and tobacco products are prohibited in the RCA. Eating, smoking, dipping, chewing or loitering in the RCA is prohibited. Drinking is allowed only when approved by the Radiation Protection Manager.

6.1.2 All routine entries into the RCA require an RWP/GAP.

6.1.2.1 Escorted Radiation Workers and Members of the Public are exempt from RWP/GAP requirements. Responsibilities for Escorted Radiation Workers and Members of the Public are specified in Section 6.5 and 6.7, respectively.

6.1.3 Entries to the RCA, during accident or emergency conditions, shall be in accordance with EPP-116.

6.1.4 Armed Security personnel responding to intruders should have unrestricted access.

6.1.4.1 The on-coming Security shift should obtain their DLR badge prior to assuming a post.
[AI-CR-2011-002292-1]

> **NOTE:** If possible, responders should log in before a drill to prevent unnecessary DLR badge exchange.

6.1.4.2 In the event of a drill or actual intrusion by unauthorized personnel, responders may enter the RCA, at any location, without logging in, as long as their DLR badge is worn.

6.1.4.2.1 If the responder entered the RCA but did not log in, their DLR badge should be processed in accordance with RPI-516.
[AI-CR-2011-002292-1]

6.1.4.3 After the drill or intrusion is terminated, responders should exit Unit 2 Access Control for manual dose tracking and contamination monitoring.

6.1.5 Personnel should not enter the RCA with open wounds, cuts or abrasions. If entry is necessary, a bandage shall be applied and Radiation Protection shall be notified of the injury prior to entry.

[C] 6.1.6 All permanent station personnel, who are required to work in the RCA, shall complete Radiation Worker Training prior to being allowed to work in the RCA.
[00800]

6.2 <u>Radiation Work Permits/General Access Permits</u>

6.2.1 RWPs should have ALARA Planning in accordance with the requirements of STA-657.

[C] 6.2.2 An RWP/GAP shall be initiated as necessary upon review of the Impact Screen in the Work Process Computer System. An RWP/GAP number may be assigned at this time.
[00796]

[C] 6.2.3 The RWPs are reviewed and approved by a Radiation Protection Supervisor, or designee.
[00796]

[C] 6.2.4 GAPs are reviewed and approved by the Radiation Protection Manager or designee.
[00796]

6.2.5 The original RWP/GAP may be maintained in the Radiation Protection office. Copies of the RWP/GAP should be readily available for individuals to review.

6.2.6 If a RWP/GAP becomes invalid due to a change in radiological conditions, the RWP/GAP should be revised and reissued.

6.2.7 At the end of the job, Radiation Protection shall terminate the RWP/GAP and transmit the original to Station Records in accordance with STA-302.

6.2.7.1 GAPs are normally active from date of initiation to December 31st of the respective year.

6.2.7.2 RWPs are active for the duration of the specific task, which includes any post work testing.

6.3 General Access Control Requirements

6.3.1 Individuals entering the RCA should review the latest survey data for the work area and their respective RWP/GAP.

NOTE:	The following applies to entries made into the RCA designating when a radiological self-brief can be performed. See Attachment 8E for additional non- radiological impact areas of the plant that may be self-briefed. **[CR-2016-003857]**

6.3.1.1 The following conditions are applicable to performing Self-Briefings:
[CR-2016-003857]

- Work area is $\leq$ 25mRem/hour
- Contamination areas are $\leq$10,000 dpm/100cm2
- No entry into alpha level 2 or 3 zones
- Areas $\leq$0.25 DAC
- No entry above 7 feet except for areas approved in Attachment 8E.
- No entry High Radiation Areas
- No abrasive work activities on contaminated systems or components (grinding, cutting, welding)
- No transfer of radioactive materials (> 2 mr/hr contact)
- No opening contaminated containers
- No contaminated system breaches
- No valve operations that could change radiological conditions 1

6.3.2 Individual entering the RCA should complete a Radiation Worker RCA Card prior to accessing the RCA. See Attachment 8.D for an example.
[CR-2010-004990]

[C] 6.3.3 Access and egress to the primary RCA should be made through Unit 2 Access Control during normal plant operations. During refueling outages and dry cask storage campaigns the Containment Access may be used in the Unit 1 Access area room 1-033.
[06591]

NOTE:	The following applies exclusively to entries made into the RCA to access the Chemistry Laboratories.

6.3.3.1 Members of the Chemistry Department may use the Unit 1 Access Hallway to enter the Primary RCA under the following conditions: **[CR-2010-010130]**

- A Dosimetry reading turnstile is present and functional at the Unit 1 RCA boundary.
- Chemistry personnel report to the Unit 2 Access Control at the start of each shift to discuss laboratory activities.
- The turnstile is affixed with a posting that states “For Chemistry Lab Re-entry Only”.
- Chemistry personnel complete a Radiation Worker RCA Card and keep it with them for the duration of the shift.
- Chemistry personnel exit the RCA through Unit 2 Access Control.
- Entries made into any other area of the RCA should be through Unit 2 Access Control in accordance with this procedure.

6.3.4 Individuals should limit the amount of paperwork taken into the RCA. Tools for use in the RCA are available from the Hot Tool Room. Tools obtained from facilities outside the RCA that are readily available from the hot tool room should NOT be taken into the RCA.

[C] 6.3.5 While in the RCA, protective clothing shall be used in accordance with the RWP and STA-653.
[10819]

6.3.6 Frisking periodically, while in the RCA, is a good radiation worker practice. However, individuals should frisk at any time contamination is suspected.

6.3.7 Radiation Workers are not allowed to move, alter or adjust radiological postings and boundaries.

6.3.7.1 Continuous Radiation Protection coverage is required if access to a posted area is required to move, alter or adjust any radiological boundary. Only Radiation Protection personnel can move boundaries.
[CR-2015-010587]

6.3.7.2 Access to a posted HRA which does not have a formal access point requires continuous Radiation Protection coverage.

[C] 6.3.8 Individuals shall release items from the RCA using the Tool and Equipment Monitor located at Access Control in accordance with STA-652. Any items left for release by Radiation Protection should be tagged, as necessary, with the appropriate department, contact and extension. **[00816]**

[C] 6.3.9 Individuals shall be monitored by a Personal Contamination Monitor or shall perform a whole body frisk prior to exiting the RCA at any point. **[00816][01811]**

6.4 <u>Processing Radiation Workers for RCA Access</u>

6.4.1 Radiation Workers should obtain their DLR badge at the DLR badge Storage Racks on the 810' Hallway. Security personnel should obtain DLR badges from the designated storage location at the Alternate Access Point (AAP) Arms Room.

6.4.2 Radiation Workers should obtain a self-reading dosimete~~r~~ at Access Control.

> **<u>NOTE:</u>** For steps 6.4.3 and 6.4.4, refer to Attachment 8.C for RP Computer System log in instruction.

[C] 6.4.3 Radiation Workers should log in to the RCA using the RP Computer System. **[01806]**

> **<u>NOTE:</u>** Radiation Workers performing activities of low radiological risk are not required to inform Radiation Protection of RCA entry. A Radiological Self-Brief should be performed prior to entry by the work group. **[CR-2016-003857]**

6.4.4 Radiation Workers performing activities with low radiological risk may enter the RCA with a completed Radiation Worker RCA Card. Radiation Workers performing activities that are not self-briefed should contact RP prior to entering the RCA and complete the Radiation Worker RCA Card. **[CR-2010-004990] [CR-2016-003857]**

6.4.6 A specific High Radiation Area (HRA) briefing is required prior to accessing a posted HRA. Upon completion of briefing, RP will initial and date the Radiation Worker RCA Card acknowledging the briefing has occurred. **[CR-2010-004990]**

6.4.7 If the RP Computer System is unavailable a manual entry should be recorded on STA-656-5 until system becomes available.

[C] 6.5 Escorted Radiation Workers

Individuals performing work inside the RCA should normally obtain Radiation Worker Training qualifications. Under unusual/extenuating circumstances, the individual may be allowed entry into the RCA as an Escorted Radiation Worker.
[00786]

6.5.1 Individuals should not be granted Escorted Radiation Worker status without the authorization of a RP Supervisor or Qualified Radiation Protection Technician.

6.5.2 Escorted Radiation Workers shall be escorted at all times by a qualified Radiation Worker. The qualified radiation worker performing escort duties may turn the Escorted Radiation Worker over to another qualified radiation worker in the field, without initializing any additional documentation.

6.5.3 During emergencies, personnel from offsite agencies or unqualified site personnel should be allowed immediate access to the RCA as Escorted Radiation Workers. STA-656-3 should be completed immediately after the entry. Radiation Protection should provide a qualified Radiation Worker escort for emergency personnel entering the RCA. The whole body count requirement prior to RCA entry should be waived by the RP Supervisor or designee, as appropriate.

6.5.4 If the Escorted Radiation Worker requests that his exposure record be entered on PADS, the worker must sign SEC-120-1, Comanche Peak Nuclear Power Plant NEI Standard Consent form. The consent form should be stapled to STA-656-3 for Dosimetry.

6.5.5 Escorted Radiation Workers shall complete Section 1 of STA-656-3. The individual should provide an estimate of current year exposure. Escorted Radiation Workers should have a qualitative whole body count performed using a PM-7 or GEM-5 prior to entry into the RCA. Have the individual step into a PM-7 or GEM-5 and document on STA-656-3 that no alarms occurred. If the Individual alarms the PM-7 or GEM-5 a quantitative whole body count is required prior to RCA Entry.

6.5.6 If an Escorted Radiation Worker declares her pregnancy, have her report to RP (Dosimetry) to complete the necessary paper work. RP (Dosimetry) should initiate an STA-655-10. RP (Dosimetry) should ensure the Escorted Radiation Worker understands the monitoring requirements in STA-655 and that she is responsible for adhering to the requirements.

6.5.7 Escorted Radiation Workers should NOT be allowed access to Locked High Radiation Areas or Very High Radiation Areas, unless sufficient training is provided or documented.

6.5.8 Escorted Radiation Workers should be limited to 100 mrem during the monitoring period. In the event pre-job dose estimates indicate a projected dose greater than 100 mrem, initiate restriction changes in accordance with Section 6.6, Restriction Changes for Escorted Radiation Workers.

6.5.9 Verify, using the RP Computer System, that the individual does not already have a DLR badge assigned. Assign a DLR badge and record the DLR badge number on STA-656-3. Complete the DLR badge label with the individual's name and the last four digits of their SSN or Employee ID number, if available. **[CR-2001-002095]**

6.5.10 Verify that Section I of STA-656-3 has been completed properly and brief the Escorted Radiation Worker on the radiological conditions in the area(s) to be entered. Complete Section II of STA-656-3.

6.5.11 Radiation Protection should provide the Escorted Radiation Worker a copy of Attachment 8.A, Instructions for Radiation Workers Entering the CPNPP Radiologically Controlled Area.

6.5.12 If there are no restriction changes, then draw through Section III and NA. If restriction changes are needed after Section III has been drawn through, a new STA-656-3 should be initiated.

[C] 6.5.13 The Escorted Radiation Worker shall be issued a self-reading dosimeter. **[00297]**

6.5.14 Each Access Event for the Escorted Radiation Worker should be recorded on page 2 of STA-656-3.

1. Radiation Protection should record the following information for entry:

   - Escorted Radiation Worker's Name & SSN, if coming from USA or Escorted Radiation Worker's Name & Unique Identification Number (e.g., Passport Number, Canadian Social Insurance Number, etc.), if coming from a country other than USA. **[CR-2012-002548]**
   - Administrative Exposure Level (mrem)
   - Date
   - Radiation Worker Escorts should sign their name and record their Employee ID and RWP/GAP.
   - Self-reading dosimeter Serial Number
   - Time In/Dose Reading In

2. Radiation Protection should record the following information for exit:

- Time Out/Dose Reading Out
- The Escorted Radiation Worker should sign their name for dose verification purposes
- Radiation Protection should initial entry as being complete and verified correct.
- Radiation Protection should total the dose estimate and verify the escorted radiation worker's dose margin remaining.

6.5.15 STA-656-3 forms are processed quarterly or as determined by the RP Supervisor.

6.6 <u>Restriction Changes for Escorted Radiation Workers</u>

6.6.1 Escorted Radiation Workers requesting restriction changes such as access to Contamination Areas, High Contamination Areas, Airborne Radioactivity Areas, high/medium risk RWP tasks, or to increase their Administrative Exposure Level must have Section III of STA-656-3 completed. An RP Supervisor or designee should complete Section III of STA-656-3 by initialing each required change and signing the authorization line.

6.6.2 If the Escorted Radiation Worker's Administrative Exposure Level is increased to greater than <u>100 mrem</u> or if their current year estimate is greater than <u>2000 mrem</u>, then initiate STA-655-8.

6.6.3 The Escorted Radiation Worker should complete STA-655-8. Ensure the individual includes the required exposure data and that the form is signed and dated.

6.6.4 The individual should complete the Qualitative WBC Data portion of STA-655-8 as well. This may be a duplicate signature/date from STA-656-3.

6.6.5 Staple STA-655-8 to the respective STA-656-3 for Dosimetry.

6.7 <u>Members of the Public</u>

[C] 6.7.1 Members of the Public shall be escorted at all times by a qualified Radiation Worker while inside the RCA.
[00786]

6.7.2 Members of the Public should be limited to a deep dose equivalent of <u>20 mrem</u> per calendar quarter.

6.7.3 Members of the Public shall not be allowed access to Contamination Areas, Airborne Radioactivity Areas, High Radiation Areas, Locked High Radiation Areas, or Very High Radiation Areas.

6.7.4 Members of the Public should not perform work.

[C] 6.7.5 Members of the Public shall wear a self-reading dosimeter while in the RCA. A DLR badge is not required.
[00297]

6.7.6 The member of the public should print his/her name and sign the signature block on STA-656-6.

6.7.7 The member of the public's qualified Radiation Worker escort should print his/her name and sign the Escort's signature block on STA-656-6.

6.7.8 A qualified Radiation Protection Technician should log the date, self-reading dosimeter number, Time In and Dose In, the appropriate section of STA-656-6.

6.7.9 Radiation Protection should issue a self-reading dosimeter to the member of the public.

6.7.10 Radiation Protection should provide the member of the public a copy of Attachment 8.B, Instructions for Members of the Public Entering the CPNPP Radiologically Controlled Area, and provide a radiological brief for entry.

6.7.11 When the member of the public exits the RCA, Radiation Protection should read the self-reading dosimeter, inform the member of the public of his/her exposure (if any), enter the exit time, exit dose and total the dose on STA-656-6.

6.7.12 STA-656-6 does NOT require Radiation Protection Dosimetry review.

6.7.13 Upon completion of STA-656-6, Radiation Protection should forward the form to the Station Records Center in accordance with STA-302.

6.8 <u>Changing RWP/GAP in the RCA</u>

6.8.1 At Radiation Protection's discretion, personnel anticipating the need to change from one RWP/GAP to another while inside the RCA may do so provided the following conditions are met:

1. The individual has reviewed the applicable RWP requirements prior to making the change.

2. The individual has attended any necessary pre-job briefs or mockup training.

3. The individual has followed normal entry/exit procedures at the control point workstation within the RCA using the RP Computer system.

6.9 Other RCAs

[C] Alternate/Satellite RCAs consisting of radiation and/or contamination areas may be established outside of the Primary Plant. Radiation Protection personnel are responsible for determining and posting the entry and exit requirements of the areas.
[06591]

6.9.1 Requirements for these areas should include provisions for the use of an RWP/GAP.

6.9.2 Exit monitoring requirements are posted when they differ from the normal exit monitoring requirements at the primary RCA.
[CR-2010-011406]

6.9.3 Personnel exiting these areas should use a hand-held frisker if no PCM is available and then pass through a PCM as soon as practical.

6.9.4 If the area is an RCA only because of dose rates and there are no radioactive material storage containers or contamination sources in the area, contamination monitoring is not required.
[CR-2011-005658]

6.10 Exposure Reports

Current total effective dose equivalent (TEDE) exposure can be displayed by the RP Computer System for individual Radiation Workers upon entry and exit from the RCA, with the exception of Escorted Radiation Workers. A hardcopy report of this data may be generated upon request.

7.0 FIGURES

None

8.0 ATTACHMENTS/FORMS

8.1 Attachments

8.1.1 Attachment 8.A, Instructions for Escorted Radiation Workers Entering the CPNPP Radiologically Controlled Area

8.1.2 Attachment 8.B, Instructions for Members of the Public Entering the CPNPP Radiologically Controlled Area

8.1.3 Attachment 8.C, Example Log In and Log Out Instructions for Radiation Workers

8.1.4 Attachment 8.D, Radiation Worker RCA Card Example

8.1.5 Attachment 8E, Non-Radiological Impact Areas

8.2 Forms

8.2.1 STA-656-2, Radiation Work Permit

8.2.2 STA-656-3, Escorted Radiation Worker Access Permit

8.2.3 STA-656-4, General Access Permit

8.2.4 STA-656-5, Radiologically Controlled Area Authorized List

8.2.5 STA-656-6, Member of the Public Access Log

9.0 RECORDS

When completed, the following forms, reports, or other documents generated in response to this procedure shall be dispositioned in accordance with STA-302.

9.1 STA-656-2, Radiation Work Permit

9.2 STA-656-3, Escorted Radiation Worker Access Permit

9.3 STA-656-4, General Access Permit

9.4 STA-656-5, Radiologically Controlled Area Authorized List

9.5 STA-656-6, Member of the Public Access Log

ATTACHMENT 8.A
PAGE 1 OF 2

INSTRUCTIONS FOR ESCORTED RADIATION WORKERS ENTERING THE CPNPP RADIOLOGICALLY CONTROLLED AREA

[C] 1. You shall be escorted by a qualified Radiation Worker at all times. **[00786]**

[C] 2. You shall be issued a self-reading dosimeter and DLR badge. The self-reading dosimeter and DLR badge should be worn on the upper front of your body between the head and the waist unless instructed by a Radiation Protection Technician to wear it in another location. The clip should be placed in the back. **[00297]**

3. You should be limited to a dose of <u>100 mrem</u> for the duration of your visit unless you have requested a change in Radiation Worker Status by completing STA-656-3 and STA-655-8.

4. If at any time, you lose, misplace or damage your self-reading dosimeter or DLR badge, you should report directly to your escort and then immediately return to Access Control.

5. If at any time, you receive a dose alarm indication on your self-reading dosimeter you should report immediately to Radiation Protection at the Access Control office.

[C] 6. Areas of the facility where radiation or radioactive materials are present are marked with a black and yellow or magenta and yellow sign containing the standard three-bladed radiation symbol. You and your escort shall obey such postings as you travel through the plant. Your escort may have access to areas which you do not have access. **[10860]**

[C] 7. You shall <u>NOT</u> enter any of the following radiologically posted areas without the express written authorization (Restriction Changes) from Radiation Protection: Contamination Areas, High Contamination Areas, Airborne Radioactivity Areas, or high/medium risk RWP tasks. Remember that your escort may have access to these areas but you do not. If you, or your escort, have questions concerning entry to posted areas, contact Radiation Protection at extension 8081 or on the plant page system. **[10860]**

8. In accordance with T.S. 6.12.1, an escorted radiation worker is exempt from RWP requirement(s) during the performance of assigned duties in high radiation areas, provided they follow plant procedures for entering into a high radiation area(s). These requirements have been incorporated in plant procedures. Therefore, adherence to plant procedures will meet the intent of the Technical Specifications.

ATTACHMENT 8.A
PAGE 2 OF 2

INSTRUCTIONS FOR ESCORTED RADIATION WORKERS ENTERING THE CPNPP RADIOLOGICALLY CONTROLLED AREA

9. Under NO circumstances should an Escorted Radiation Worker enter a Locked High Radiation Area or Very High Radiation Area unless sufficient training is provided or documented.

10. You shall NOT eat, smoke, dip or chew in the RCA. Drinking is allowed only when approved by the Radiation Protection Manager.

Effects of Radiation Exposure

While it is generally accepted in the scientific community that exposure to low levels of ionizing radiation is safe, CPNPP is firmly committed to keeping exposure to radiation as low as reasonably achievable. Should you have questions on the effects of radiation, please contact a member of the Radiation Protection staff.

Prenatal Radiation Exposure

The Nuclear Regulatory Commission has prescribed that the radiation dose to an unborn child as, a result of exposure to the mother, not exceed 500 mrem for the gestation period. If you are pregnant, or think you might be pregnant, and wish to formally declare your pregnancy, notify Radiation Protection before you enter the RCA and initiate STA-655-10. In addition, Regulatory Guide 8.13, Instruction Concerning Prenatal Radiation Exposure, should be provided to the individual prior to entering the radiologically controlled area, whether or not a declaration is made.

Emergencies

Should an abnormal event occur resulting in an emergency, your escort is trained to handle the situation. Your first indication will be one of several loud siren-like alarms. The alarm signal shall identify the type of emergency and dictate the actions your escort will take. If there is a building evacuation in the RCA, your escort will direct you to the designated assembly area where you should await further instructions.

[C] Violations and Suggestions

If during your employment at the site, you observe a situation which appears to be a violation of federal laws, or which causes unnecessary exposure of individuals to radiation, please bring it to the attention of your escort.
[10860]

ATTACHMENT 8.B
PAGE 1 OF 2

INSTRUCTIONS FOR MEMBERS OF THE PUBLIC ENTERING THE CPNPP RADIOLOGICALLY CONTROLLED AREA

[C] 1. You shall be escorted by a qualified Radiation Worker at all times.
[00786]

[C] 2. You shall wear a self-reading dosimeter.
[00297]

3. You should be limited to a dose of <u>20 mrem</u> per quarter while visiting CPNPP.

4. The self-reading dosimeter should be worn on the upper front of your body between the head and the waist. The clip should be placed in the back.

5. If at any time, you receive an alarm indication on your self-reading dosimeter, you should contact Radiation Protection at extension 8081.

6. If at any time, you lose, misplace, or damage your dosimeter you should report directly to your escort and then immediately return to Radiation Protection at Access Control.

[C] 7. Areas of the facility where radiation or radioactive materials are present are marked with a black and yellow or magenta and yellow sign containing the standard three-bladed radiation symbol. You and your escort shall obey such postings as you travel through the plant.
[10860]

[C] 8. You shall <u>NOT</u> enter any of the following radiologically posted areas: High Radiation Area, Locked High Radiation Area, Very High Radiation Area, Contamination Area, or Airborne Radioactivity Area. If you or your escort have questions concerning entry to posted areas contact Radiation Protection at extension 8081 or on the plant page system.
[10860]

9. You shall <u>NOT</u> eat, smoke, dip or chew in the RCA. Drinking is allowed only when approved by the Radiation Protection Manager.

ATTACHMENT 8.B
PAGE 2 OF 2

INSTRUCTIONS FOR MEMBERS OF THE PUBLIC ENTERING THE CPNPP RADIOLOGICALLY CONTROLLED AREA

Effects of Radiation Exposure

While it is generally accepted in the scientific community that exposure to low levels of ionizing radiation is safe, CPNPP is firmly committed to keeping exposure to radiation as low as reasonably achievable. Should you have questions on the effects of radiation, please contact a member of the Radiation Protection staff.

Emergencies

Should an abnormal event occur resulting in an emergency, your escort is trained to handle this situation. Your first indication will be one of several loud siren-like alarms. The alarm signal shall identify the type of emergency and dictate the actions your escort will take. If there is a building evacuation in the RCA, your escort will direct you to the designated assembly area where you should await further instructions.

[C] Violations and Suggestions

If during your employment at the site, you observe a situation which appears to be a violation of federal laws, or which causes unnecessary exposure of individuals to radiation, please bring it to the attention of your escort.
[10860]

ATTACHMENT 8.C
PAGE 1 OF 1

EXAMPLE LOG IN AND LOG OUT INSTRUCTIONS FOR RADIATION WORKERS

The following steps are an example of how Radiation Workers should log in and out of the RCA using the RP Computer System.

Log In/Entry:

1. Obtain a self-reading dosimeter from the bin.
2. Insert the self-reading dosimeter into the reader and scan badge.
3. Enter all information as requested when prompted.
4. Verify all information is correct.
5. Wait until the dosimeter setup is complete and access is permitted.
6. Remove the dosimeter and ensure it has been turned on.

Log Out/Exit:

1. Insert self-reading dosimeter into reader.
2. Scan badge.
3. Verify all exit information is complete.
4. Wait until prompted to remove the dosimeter from the reader.
5. After removing the dosimeter from the reader, ensure it has been turned off.
6. Return the dosimeter to the bin.

ATTACHMENT 8.D
PAGE 1 OF 1

RADIATION WORKER RCA CARD EXAMPLE

RADIATION WORKER RCA CARD

Name ______________________________

RWP/GAP# ______________ Task# ________

Location or Area/Specific Component:
____

Work to be performed:
____

Self-Reading Dosimeter Alarms
Dose Alarm: __________ mRem
Rate Alarm: __________ mR/hr

Work Area Information
Maximum dose rates: _____ mR/hr
My dose goal __________mRem

Contam. Levels or range ___________ dpm/100cm-2

Am I entering a posted HRA? YES NO (Circle One)

(If you circle YES a briefing is required and the RP giving brief initials this form)

RP Tech's Initials ___________ Date__________

ATTACHMENT 8.E
PAGE 1 OF 2
NON-RADIOLOGICAL IMPACT AREAS

NOTE: The following is a listing of rooms and areas in which access to elevations >7' in the overhead is allowed without notification of Radiation Protection. All other locations not included on this will require Radiation Protection notification.

Room # and Name	Elevation	Map Type	Map Title	Survey Frequency
1-072 1-01 AFW PMP	790'	One Line	M3SAT	Monthly
1-073 1-02 AFW PMP	790'	One Line	M3SAT	Monthly
1-074 Turbine AFW PMP	790'	One Line	M3SAT	Monthly
X-115A Safety Chiller Room	790'	One Line	M3SAT	Monthly
X-115B Safety Chiller Room	790'	One Line	M3SAT	Monthly
2-072 2-01 AFW PMP	790'	One Line	M4SAT	Monthly
2-073 2-02 AFW PMP	790'	One Line	M4SAT	Monthly
2-074 Turbine AFW PMP	790'	One Line	M4SAT	Monthly
1-083 Trn A Switchgear room	810'	One Line	M3SAT	Monthly
Unit 1 Diesel (all rooms)	810'	One Line	M2SUN	Monthly
Unit 1 Diesel (all rooms)	844'	One Line	M2SUN	Monthly
2-083 Trn A Switchgear room	810'	One Line	M4SAT	Monthly
Unit 2 Diesel (all rooms)	810'	One Line	M4SAT	Monthly
Unit 2 Diesel (all rooms)	844'	One Line	M4SAT	Monthly
1-082 U-1 SG Corridor	810'	Survey	1-082	Monthly
2-082 U-2 SG Corridor	810'	Survey	2-082	Monthly
X-197 1-01 CCW PMP room	810'	One Line	M3SAT	Monthly
X-198 1-02 CCW PMP Room	810'	One Line	M2SUN	Monthly
X-204 2-01 CCW PMP Room	810'	One Line	M3SAT	Monthly
X-205 2-02 CCW PMP Room	810'	One Line	M2SUN	Monthly
1-094 U-1 SG Corridor	832'	Survey	1-094	Monthly
2-094 U-2 SG Corridor	832'	Survey	2-094	Monthly
1-096 ELEC EQUIP RM	832'	One Line	M1SUN	Monthly
2-096 ELEC EQUIP RM	832'	One Line	M1SUN	Monthly
1-100 HP Chem FD Rm	852'	One Line	M2SAT	Monthly
1-100A-H FW Valve Rm	852'	One Line	M2SAT	Monthly
1-104 FW HVAC Rm	852'	One Line	M2SAT	Monthly
1-105 Trn B Switchgear Rm	852'	One Line	M2SAT	Monthly
2-100 HP Chem FD Rm	852'	One Line	M1SAT	Monthly
2-100A-H FW Valve Rm	852'	One Line	M1SAT	Monthly
2-104 FW HVAC Rm	852'	One Line	M1SAT	Monthly

ATTACHMENT 8.E
PAGE 2 OF 2
NON-RADIOLOGICAL IMPACT AREAS

NOTE: The following is a listing of rooms and areas in which access to elevations >7' in the overhead is allowed without notification of Radiation Protection. All other locations not included on this will require Radiation Protection notification.

Room # and Name	Elevation	Map Type	Map Title	Survey Frequency
2-105 Trn B Switchgear Rm	852'	One Line	M1SAT	Monthly
X-241 Corridor	852'	Survey	X241	Monthly
X-244 Lwr Primary Vent Filter Rm	873'	One Line	M2SAT	Monthly
X-245 Ventilation Rm	873'	One Line	M2SAT	Monthly
1-107 U-1 Atmos Relief Vlv Rm	873'	One Line	M2SAT	Monthly
2-107 U-2 Atmos Relief Vlv Rm	873'	One Line	M1SAT	Monthly
X-246 Upper Primary Vent Filter Rm	886'	One Line	M2SAT	Monthly

Initial Conditions: **Given the following conditions:**

- **Two pump experts have been brought onsite to assess the status of a damaged Centrifugal Charging Pump that has been repaired**
- **Plant management has requested that you escort and coordinate the assessment with the pump experts**
- **The pump experts have NOT been authorized for any DOSE beyond the normal Administrative Limits for an Escorted Radiation Worker**
- **The assessment is anticipated to take 2 hours**
- **The general dose rate in the area is 70 mrem / hour but can be reduced to 20 mrem / hour if lead shielding is installed**
- **Escorted Radiation Worker 'A' is a 40 year-old male that has received 250 mrem this year**
- **Escorted Radiation Worker 'B' is a 29 year-old female that has declared her pregnancy to Radiation Protection. She has received 5 mrem this year**

Initiating Cue: **The Shift Manager directs you to PERFORM the following:**

- **DETERMINE if Escorted Radiation Worker 'A' can perform the assessment without shielding**
  - **Escorted Radiation Worker 'A'** CANNOT **perform the assessment without shielding**
- **DETERMINE if Escorted Radiation Worker 'B' can perform the assessment without shielding**
  - **Escorted Radiation Worker 'B'** CANNOT **perform the assessment without shielding**
- **DETERMINE if Escorted Radiation Worker 'A' can perform the assessment with shielding and without an exposure extension.**
  - **Escorted Radiation Worker 'A'** CAN **perform the assessment with shielding and without an exposure extension**
- **DETERMINE if Escorted Radiation Worker 'B' can perform the assessment with shielding and without an exposure extension**
  - **Escorted Radiation Worker 'B'** CAN **perform the assessment with shielding and without an exposure extension**

Facility: CPNPP JPM # NRC SA1 Task # SO1005 K/A # 2.1.23 4.3 / 4.4

Title: Perform RCS Pressure / Temperature Verification and Evaluate Technical Specifications

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- ABN-905A, Loss of Control Room Habitability, Attachment 7, RCS Pressure / Temperature Verification, is in progress.
- Reactor Coolant System cooldown is in progress.

Initiating Cue: The Shift Manager directs you to PERFORM the following:

- UTILIZING the data provided, CALCULATE the identified parameters (shown with arrows) on Attachment 7, RCS Pressure/Temperature Verification, per ABN-905A, Loss of Control Room Habitability.
- When complete, IDENTIFY all Technical Specification CONDITIONs, REQUIRED ACTIONs, and COMPLETION TIMEs if any.

____

____

____

Task Standard: UTILIZED ABN-905A, CALCULATED saturation temperatures, Reactor Coolant System subcooling margin, and Reactor Coolant System cooldown rate during a Loss of Control Room Habitability.

UTILIZED Unit 1 Technical Specifications, IDENTIFIED LCO 3.4.3 CONDITION A, REQUIRED ACTIONS, and COMPLETION TIME.

Required Materials: ABN-905A, Loss of Control Room Habitability, Rev. 9.

Unit 1 Technical Specifications, Amendment 165.

Pressure and Temperature Limits Report, ERX-07-003, Rev. 2.

Validation Time: 17 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ____________

CLASSROOM SETUP

EXAMINER:

PROVIDE the examinee with a copy of:

- **ABN-905A, Loss of Control Room Habitability (Procedure 1).**

AND

- **Attachment 7, RCS Pressure / Temperature Verification with data inserted where appropriate (Handout).**

MAKE the following available in the classroom:

- **Unit 1 Technical Specifications (Procedure 2).**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following is from ABN-905A, Attachment 7.**
Perform Step: 1	DETERMINE saturation temperature for Pressurizer pressure using Steam Tables at 0900, 0930, and 1000.
Standard:	DETERMINED saturation temperature for Pressurizer pressure using Steam Tables and ENTERED data at 0900, 0930, and 1000.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2	CALCULATE subcooling for Reactor Coolant System using Steam Tables at 0900, 0930, and 1000.
Standard:	CALCULATED subcooling for Reactor Coolant System using Steam Tables and ENTERED data at 0900, 0930, and 1000.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3	DETERMINE saturation temperature for Steam Generator 1 pressure using Steam Tables at 0900, 0930, and 1000.
Standard:	DETERMINED saturation temperature for Steam Generator 1 pressure using Steam Tables and ENTERED data at 0900, 0930, and 1000.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4	DETERMINE saturation temperature for Steam Generator 2 pressure using Steam Tables at 0900, 0930, and 1000.
Standard:	DETERMINED saturation temperature for Steam Generator 2 pressure using Steam Tables and ENTERED data at 0900, 0930, and 1000.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 5	DETERMINE saturation temperature for Steam Generator 3 pressure using Steam Tables at 0900, 0930, and 1000.
Standard:	DETERMINED saturation temperature for Steam Generator 3 pressure using Steam Tables and ENTERED data at 0900, 0930, and 1000.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 6	DETERMINE saturation temperature for Steam Generator 4 pressure using Steam Tables at 0900, 0930, and 1000.
Standard:	DETERMINED saturation temperature for Steam Generator 4 pressure using Steam Tables and ENTERED data at 0900, 0930, and 1000.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 7√	CALCULATE Reactor Coolant System cooldown rate from the Steam Generator with the largest pressure drop at 0930 and 1000.
Standard:	CALCULATED the 0930 Reactor Coolant System cool down rate and DETRMINED Steam Generators 1, 2, and 3 (all had the same pressure drop) had the largest pressure drop between 0900 and 0930 and ENTERED data at 0930. **(not critical)** CALCULATED the 1000 Reactor Coolant System cool down rate and DETERMINED Steam Generator 4 had the largest pressure drop between 0930 and 1000 and ENTERED data at 1000. **(critical)**
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 8√	Identify any Technical Specification CONDITION, REQUIRED ACTION, and COMPLETION TIME.

Standard:	DETERMINED Technical Specification LCO 3.4.3, RCS Pressure and Temperature Limits is applicable:
	• CONDITION A: Requirements of the LCO not met in MODE 1, 2, 3, or 4.
	• REQUIRED ACTION and COMPLETION TIME:
	  • A.1 – Restore parameter(s) to within limits in 30 minutes.
	AND
	  • A.2 – Determine RCS is acceptable for continued operation within 72 hours.

Terminating Cue:	**This JPM is complete.**
Comment:	**SAT** ☐ **UNSAT** ☐

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **ABN-905A, Loss of Control Room Habitability, Attachment 7, RCS Pressure / Temperature Verification, is in progress.**
- **Reactor Coolant System cooldown is in progress.**

Initiating Cue: **The Shift Manager directs you to PERFORM the following:**

- **UTILIZING the data provided, CALCULATE the identified parameters (shown with arrows) on Attachment 7, RCS Pressure/Temperature Verification, per ABN-905A, Loss of Control Room Habitability.**
- **When complete, IDENTIFY all Technical Specification CONDITIONs, REQUIRED ACTIONs, and COMPLETION TIMEs if any.**

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COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

ABNORMAL CONDITIONS PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____/____ LATEST PCN/EFFECTIVE DATE 15 / 12/15/16 1200

QUALITY RELATED

LOSS OF CONTROL ROOM HABITABILITY

PROCEDURE NO. ABN-905A

REVISION NO. 9

EFFECTIVE DATE: 10/23/07 1200

PREPARED BY (Print): J.D. STONE Ext: 0564

TECHNICAL REVIEW BY (Print): JIM BRAU Ext: 5443

APPROVED BY: Alan Hall for Dave Kross Date: 10/01/07
DIRECTOR, OPERATIONS

1.0 APPLICABILITY

This procedure describes the actions to be taken for a loss of habitability in the control room. This procedure DOES NOT apply if habitability is lost due to a fire within the Control Room or Cable Spreading Room. This procedure applies to Unit 1 operation only.

This procedure is applicable for initiating events occurring in Modes 1 and 2. This procedure assumes RHR is not operating and SI is operable. Using this procedure when not in one of these modes requires a step by step evaluation to determine if the required action is still applicable to current plant conditions.

This procedure should NOT be used for testing purposes. Transferring equipment from Control Room control to Remote Shutdown Panel control defeats all automatic Engineered Safety Features (ESF) actuations associated with the equipment. This procedure transfers many ESF components from both trains. This would place the unit into Technical Specification 3.0.3 action statement.

2.0 LOSS OF CONTROL ROOM HABITABILITY

2.1 Symptoms

a. Annunciator Alarms

None

b. Plant Indications

- Heavy smoke within the Control Room with no indications of fire within the Control Room or Cable Spreading Room
- Security compromise which necessitates Control Room evacuation and implementation of STA-919 controls.

2.2 Automatic Actions

None

2.3 Operator Actions

CAUTION: Use of this procedure may result in abnormal configuration. Management review of steps performed is necessary to ensure configuration tracking and restoration.

NOTE:

- The Shift Manager may make the decision not to transfer various equipment from the Control Room to the Remote Shutdown Panel based on plant condition, reason for Control Room evacuation, Technical Specifications, etc. These steps should be N/A'ed. Verification of equipment status at RSP is not required for components which remain controlled from the MCB.
- The decision to evacuate the control room shall be made by the Shift Manager, based upon the ability to safely control the plant from the Control Room.
- Once the decision to leave the Control Room has been made, Emergency Response Guidelines (ERGs) DO NOT apply. ERGs may be referred to, but should not be used for Reactor Trip Response.
- Three two-way radios are maintained at the Remote Shutdown Panel for performance of this procedure.

1. WHEN the decision has been made to evacuate Control Room, THEN perform the following:

[C] ☐ a. Trip the Reactor:

- Verify the Reactor Trip breakers - OPEN
- Verify neutron flux - DECREASING
- Verify all DRPI RB lights - ON

CAUTION: If two or more rods fail to insert, EMERGENCY BORATION will be performed either from the Remote Shutdown Panel after control has been transferred or locally using the manual emergency boration valve (1CS-8439).

NOTE: Steps b and c should be performed prior to evacuating the Control Room. Steps will be taken after the control room evacuation to ensure required actions have been completed.

☐ b. Verify Turbine Trip:

- All HP Turbine Stop Valves - CLOSED.

"Step continued next page"

2.3 Operator Actions

[C] 1. c. Transfer charging pump suction to the RWST:

☐ 1) Open 1/1-LCV-112D OR 1/1-LCV-112E, RWST TO CHRG PMP SUCT VLV.

☐ 2) Close 1/1-LCV-112B AND 1/1-LCV-112C, VCT TO CHRG PMP SUCT VLV.

☐ 3) Verify 1-ZL-8220 AND 1-ZL-8221, CHRG PMP SUCT HI POINT VENT VLV - CLOSED.

☐ 4) Close 1/1-8202A AND 1/1-8202B, VENT VLV.

☐ 5) IF charging pump performance indicates possible cavitation, THEN stop charging pump until above valves manually repositioned.

☐ 2. Ensure 1/1-LCV-112A, VCT LVL CTRL VLV selected to - HUT.

NOTE: Evaluate the necessity of donning SCBAs, if not already worn, prior to leaving Control Room.

☐ 3. Shift Manager/Unit Supervisor - obtain the Safe Shutdown Key Ring and proceed along with Reactor Operator to the Remote Shutdown Panel via safest route.

☐ 4. Relief Reactor Operator - proceed to the Remote Shutdown Panel, obtain a copy of this procedure, then proceed to Shutdown Transfer Panel.

☐ 5. IF time permits, THEN announce the Control Room Evacuation over gaitronics ALL PAGE.

6. IF time permits, THEN contact Security and inform them of the following:

☐ a. the control room evacuation

☐ b. the need to exit through the rear door

☐ c. the need to implement STA-919 controls

☐ 7. Activate the Control Room Evacuation Alarm AND ensure all personnel evacuate Control Room area.

2.3 Operator Actions

NOTE:
- The procedure should be used to document all transfers. Steps may be checked off and comments written within the procedure. Any steps that are not performed should be marked N/A and the reason/plant condition which prevents transfer written on the procedure. The Shift Manager may elect to perform steps out of sequence or concurrently, as required, to establish and maintain overall plant control.
- Attachment 7 may be started to address temperature trends now, but it is not necessary to be started until step 50.

8. On arrival at Remote Shutdown Panel vicinity, the Shift Manager/Unit Supervisor perform the following:

☐ a. Ensure Reactor Trip Breakers - OPEN:

- TBX-ESPDTS-01TA, UNIT 1 TRAIN A REACTOR TRIP BREAKER RTA
- TBX-ESPDTS-01BA, UNIT 1 TRAIN A REACTOR TRIP BYPASS BREAKER BYA
- TBX-ESPDTS-01TB, UNIT 1 TRAIN B REACTOR TRIP BREAKER RTB
- TBX-ESPDTS-01BB, UNIT 1 TRAIN B REACTOR TRIP BYPASS BREAKER BYB

NOTE: EPP-201 will be reviewed at Remote Shutdown Panel to select the appropriate emergency classification.

☐ b. Ensure Motor AND Generator Control Switches - PULL-OUT:

- 1/1-MGPS1, MG SET 1-01 GENERATOR CKT BKR CONTROL SWITCH
- 1/1-MGPS2, MG SET 1-02 GENERATOR CKT BKR CONTROL SWITCH
- 1/1-ELPS1, HAND SWITCH MOTOR 1-01 STARTING BREAKER
- 1/1-ELPS2, HAND SWITCH MOTOR 1-02 STARTING BREAKER

☐ c. Announce over Gaitronics that the Control Room has been evacuated AND designate which Gaitronics channel is the emergency operations channel.

"Step continued next page"

2.3 Operator Actions

8. ☐ d. Obtain assistance of additional onsite personnel as necessary to implement the Emergency Plan:

- Shift Technical Advisors
- Security Personnel
- Radiation Protection Technician
- Chemistry Technician
- Additional Operators (Dispatch any available operator to the OSC to monitor SPDS)

☐ e. Contact Radiation Protection to provide local monitoring of the AB 810 Rm X-203 Chrg Pmp Vlv Rm AND to provide the required dosimetry for the personnel at the Remote Shutdown Panel.

☐ f. Contact Primary Chemistry to sample RCS for boron every 30 minutes AND to perform any required I-131 sampling.

☐ g. Ensure I&C personnel are available to block SI signals when required by this procedure.

9. Dispatch an Operator to locally ensure the following:

- ☐ Main Turbine - TRIPPED
- ☐ Main Feedwater Pumps - TRIPPED
- ☐ Isolate secondary drain OR steam flow paths as directed by the Shift Manager/Unit Supervisor.

10. Dispatch an Operator to perform the following:

☐ a. IF boration is necessary, THEN locally open 1CS-8439-RO, U1 CVCS CHRG PMP EMER BORATE MAN VLV RMT OPER (AB 822 Rmt Vlv Op Rm 209).

☐ b. Align charging pump suction to the RWST per Attachment 4.

☐ c. Isolate RCS dilution paths per Attachment 4.

☐ 11. Reactor Operator - establish communications with Relief Reactor Operator at Shutdown Transfer Panel by one of the following methods:

- Safe Shutdown Sound Powered Phone System

  RSP - Jack E36A EMERGENCY LOOP - Column north of RSP

  STP - Jack E16A EMERGENCY LOOP - Column between MCC 1EB1-2 and 1EB3-2.

- Portable two-way radio system

2.3 Operator Actions

12. IF offsite power has been lost, THEN perform the following:

☐ a. Ensure the Emergency Diesel Generators operating properly.

b. Verify Natural Circulation of RCS as follows:

☐ • RCS Subcooling - GREATER THAN 25°F

☐ • SG pressures - STABLE OR DECREASING

☐ • RCS hot leg temperatures - STABLE OR DECREASING

☐ • RCS cold leg temperature - AT SATURATION TEMPERATURE FOR SG PRESSURE

☐ c. Check SFP level and conditions.

☐ 13. IF power is lost to 1EA1 or 1EA2 after control is transferred to RSP, THEN manually reload buses per Attachment 5.

[C] ☐ a. Check SFP level and conditions.

> CAUTION:
> - After the Reactor Trip auxiliary feedwater flow could cause a Safety Injection to occur due to low steam line pressure.
> - Prior to transferring any switch from CR to HSP, controller at the RSP should be positioned correctly.

> NOTE: The Turbine Driven Auxiliary Feedwater Pump may be used for controlling Steam Generator water levels if one or both MD AFW Pumps are inoperable

14. Transfer control of the Auxiliary Feedwater System as follows:

☐ a. Transfer the TD AFWP flow control valves and TD AFWP speed control to the RSP by depressing the MAN pushbutton on the controller M/A station:

- 1-SK-2452B, AFWPT SPD CTRL
- 1-FK-2459B, TD AFWP SG 1 FLO CTRL
- 1-FK-2460B, TD AFWP SG 2 FLO CTRL
- 1-FK-2461B, TD AFWP SG 3 FLO CTRL
- 1-FK-2462B, TD AFWP SG 4 FLO CTRL

☐ b. Reduce 1-SK-2452B, AFWPT SPD CTRL, to minimum.

"Step continued next page"

2.3 Operator Actions

14. ☐ c. Transfer the TD AFWP steam supply valves from CR to HSP:

- 1-HS-2452B, AFWPT MSL 4 SPLY VLV CTRL XFER (STP)
- 1-HS-2452D, AFWPT MSL 1 SPLY VLV CTRL XFER (RSP)

☐ d. Close TD AFWP steam supply valves:

- 1-HS-2452C, AFWPT MSL 4 SPLY VLV
- 1-HS-2452E, AFWPT MSL 1 SPLY VLV

☐ e. Transfer 1-HS-2456FT, MD AFWP 1 RECIRC VLV CTRL XFER, (STP) from CR to HSP.

☐ f. Open 1-HS-2456FL, MD AFWP 1 RECIRC VLV.

☐ g. Transfer Motor Driven Auxiliary Feed Pump controls from CR to HSP:

- 1-HS-2450B, MD AFWP 1 CTRL XFER (STP)
- 1-HS-2451B, MD AFWP 2 CTRL XFER (RSP)

☐ h. Ensure BOTH Motor Driven Auxiliary Feed Pumps - RUNNING:

- 1-HS-2450C, MD AFWP 1 (RSP)
- 1-HS-2451C, MD AFWP 2 (RSP)

CAUTION: If MD AFWP 2 receives an auto start signal, Train B flow controllers must be transferred back to manual and adjusted for desired flow.

☐ i. Transfer MD AFWP flow control valves from CR to HSP:

- 1-HS-2453AF, MD AFWP 1 SG 1 FLO CTRL CTRL XFER (STP)
- 1-HS-2453BF, MD AFWP 1 SG 2 FLO CTRL CTRL XFER (STP)
- 1-FK-2454C, MD AFWP 2 SG 3 FLO CTRL (RSP) (Depress MAN pushbutton on the controller M/A station).
- 1-FK-2454D, MD AFWP 2 SG 4 FLO CTRL (RSP) (Depress MAN pushbutton on the controller M/A station).

"Step continued next page"

2.3 Operator Actions

> NOTE: At 551°F, indicated level should be maintained between 63% to 68% WR level.

14. ☐ j. Adjust Auxiliary Feedwater flow controllers for each Steam Generator to maintain actual SG levels between 84% to 92% WR level. Refer to Attachment 16 for temperature correction.

> NOTE: If SG pressure can not be maintained, isolation of Main Steamlines may be necessary to prevent Low Steam Line Pressure SI. Isolating steamlines prior to having control of SG Atmos Rlf valves, could challenge SG safety valves.

☐ 15. Transfer control of SG Atmos Rlf valves to the Remote Shutdown Panel by performing Attachment 9 while continuing this procedure.

☐ 16. Transfer Service Water Pumps from CR to HSP:

- 1-HS-4250B, SSWP 1 CTRL XFER (STP)
- 1-HS-4251B, SSWP 2 CTRL XFER (RSP)

☐ 17. Ensure BOTH Service Water Pumps - RUNNING:

- 1-HS-4250C, SSWP 1 (RSP)
- 1-HS-4251C, SSWP 2 (RSP)

☐ 18. Verify Service Water flow:

- 1-FI-4258B, SSWP 1 DISCH FLO (RSP)
- 1-FI-4259B, SSWP 2 DISCH FLO (RSP)

☐ 19. Transfer Component Cooling Water Pumps from CR to HSP:

- 1-HS-4518B, CCWP 1 CTRL XFER (STP)
- 1-HS-4519B, CCWP 2 CTRL XFER (RSP)

☐ 20. Ensure BOTH Component Cooling Water Pumps - RUNNING:

- 1-HS-4518C, CCWP 1 (RSP)
- 1-HS-4519C, CCWP 2 (RSP)

2.3 Operator Actions

☐ 21. Ensure 1-HS-6710B, SFTY CH WTR CHLR BYP LCKOUT (STP) in - BYP LCKOUT.

☐ 22. Perform the following to transfer Safety Chilled Water Recirc Pump:

- Hold 1-HS-6700FL, SFTY CH WTR RECIRC PMP 5 (RSP) in - START WHILE transferring to prevent pump from tripping.
- Transfer 1-HS-6700FT, SFTY CH WTR RECIRC PMP 5 CTRL XFER (STP) from CR to HSP.

☐ 23. Ensure 1-HS-6700FL, SFTY CH WTR RECIRC PMP 5 (RSP) - RUNNING

> CAUTION: Shutdown Margin should be verified prior to any planned cooldown >10°F.

24. IF RCS cooldown is NOT controlled AND needs to be stabilized, THEN perform the following:

☐ a. WHEN control is established at RSP, THEN manually close SG Atmos Rlf vlvs.

☐ b. IF cooldown continues, THEN throttle AFW, maintaining >460 GPM until ACTUAL WR level >73% in at least one Steam Generator.

☐ c. IF cooldown continues, THEN ensure ALL MSIV's - CLOSED.

> NOTE: The following step transfers control of Pressurizer Spray valve, Train A RHR HX Outlet valve and Train A RHR Bypass valve. These valves should position to their present RSP controller demand.

☐ 25. Transfer control of RC LOOP 4 PRZR SPR VLV per Attachment 10.

[C]

> CAUTION: With pressurizer heaters in HSP position, the interlock between heaters off and low pressurizer level is over-ridden.

☐ 26. Transfer Pressurizer Heater control from CR to HSP:

- 43/1-PCPR1L, PRZR HTR BACKUP GROUP A CTRL XFER (STP)
- 43/1-PCPR2L, PRZR HTR CTRL XFER (RSP)

☐ 27. Maintain Pressurizer pressure between 2200 psig to 2300 psig by controlling Pressurizer Heaters as necessary:

- 1/1-PCPR1L, PRZR HTR BACKUP GROUP A (RSP)
- 1/1-PCPR2L, PRZR HTR BACKUP GROUP B (RSP)

☐ 28. Transfer PRZR PORV control from CR to HSP:

2.3 Operator Actions

- 43/1-455AFT, PRZR PORV CTRL XFER (STP)
- 43/1-456FT, PRZR PORV CTRL XFER (RSP)

☐ 29. Trip 1EB1/6D/BKR, 1PCPR, PRZR CTRL HTR GROUP C (red TRIP pushbutton on bottom of compartment door) AND remove associated control power fuses.

☐ 30. Trip 1EB4/11B/BKR, 1PCPR3, PRZR BACKUP HTR GROUP D (red TRIP pushbutton on bottom of compartment door) AND remove associated control power fuses.

☐ 31. WHEN control of RC LOOP 4 PRZR SPR VLV is transferred, THEN use 1-HC-455C, RC LOOP 4 PRZR SPR VLV CTRL, as necessary.

☐ 32. IF PRZR spray is NOT available, THEN use PRZR PORV(s), as necessary.

- 1/1-455AFL, PRZR PORV
- 1/1-456FL, PRZR PORV

☐ 33. Transfer 43/1-121FT, CHRG FLO CTRL CTRL XFER, (STP) from CR to HSP.

☐ 34. Transfer a Centrifugal Charging Pump from CR to HSP.

- 43/1-APCH1L, CCP 1 CTRL XFER (STP)
- 43/1-APCH2L, CCP 2 CTRL XFER (RSP)

☐ 35. Ensure Centrifugal Charging Pump - RUNNING:

- 1/1-APCH1L, CCP 1 (RSP)
- 1/1-APCH2L, CCP 2 (RSP)

☐ 36. Adjust 1-FK-121A, CHRG FLO CTRL, to maintain Pressurizer level 25% to 50% on 1-LI-459B or 1-LI-460B, PRZR LVL.

☐ 37. Trip 1EB1/2B/BKR, 1APPD, PD CHARGING PUMP (red TRIP pushbutton on bottom of compartment door) AND rack out the breaker.

2.3 Operator Actions

NOTE: RCS letdown and excess letdown are isolated by performing the following steps.

☐ 38. Transfer control of following valves to the RSP:

- 43/1-8149AL, LTDN ORIFICE ISOL VLV (45 GPM) CTRL XFER (STP)
- 43/1-8149BL, LTDN ORIFICE ISOL VLV (75 GPM) CTRL XFER (STP)
- 43/1-8149CL, LTDN ORIFICE ISOL VLV (75 GPM) CTRL XFER (STP)
- 43/1-8153FT, XS LTDN ISOL VLV CTRL XFER (RSP)

☐ 39. Close the following valves:

- 1/1-8149AL, LTDN ORIFICE ISOL VLV (45 GPM) (RSP)
- 1/1-8149BL, LTDN ORIFICE ISOL VLV (75 GPM) (RSP)
- 1/1-8149CL, LTDN ORIFICE ISOL VLV (75 GPM) (RSP)
- 1/1-8153FL, XS LTDN ISOL VLV (RSP)

NOTE: • Normal charging is isolated by the following steps. • Individual seal injection flow may be monitored locally in SFGD 810 North and South Penetration Rooms.

☐ 40. Reduce 1-FK-121A, CHRG FLO CTRL (RSP) to approximately 40 gpm.

☐ 41. Transfer 43/1-8106FT, CHRG PMP TO RCS ISOL VLV (STP) from CR to HSP.

☐ 42. Close 1/1-8106FL, CHRG PMP TO RCS ISOL VLV CTRL XFER (RSP).

☐ 43. Maintain charging flow between 24 gpm to 50 gpm (approximately 6 to 13 gpm/RCP).

2.3 Operator Actions

> NOTE:
> - Chemistry should be notified that a release has occurred and for Chemistry to determine if a release permit is required per STA-603.
> - The RSP controllers for the SG Atmos Rlf valves may operate differently than Control Room controllers. An operator may be sent to verify relief valve response during use at the RSP.

44. WHEN control of SG Atmos Rlf valves is available at the RSP, THEN transfer control of the Main Steam System as follows:

☐ a. Maintain Steam Generator pressure 1050 psig to 1150 psig using:

- 1-HC-2325, SG 1 ATMOS RLF VLV CTRL (RSP)
- 1-HC-2326, SG 2 ATMOS RLF VLV CTRL (RSP)
- 1-HC-2327, SG 3 ATMOS RLF VLV CTRL (RSP)
- 1-HC-2328, SG 4 ATMOS RLF VLV CTRL (RSP)

> NOTE: Transferring control of MSIV's to HSP, causes the MSIVs to close.

☐ b. Isolate Main Steam Lines by transferring control of MSIVs from CR to HSP, as necessary:

- 1-HS-2333FT, MSIV 1 CTRL XFER (STP)
- 1-HS-2334FT, MSIV 2 CTRL XFER (STP)
- 1-HS-2335FT, MSIV 3 CTRL XFER (STP)
- 1-HS-2336FT, MSIV 4 CTRL XFER (STP)

☐ c. Isolate Steam Generator Blowdown by closing 1-HS-5180F, SG BLDN HX OUT PRESS CTRL VLV (RSP).

2.3 Operator Actions

NOTE:	DG BKR CTRL XFER switches in HSP position defeat DG auto starts.

☐ 45. Transfer the following Train A controls from CR to HSP:

- 43/1EA1-1, INCOMING BKR 1EA1-1 CTRL XFER (STP)
- 43/1EA1-2, INCOMING BKR 1EA1-2 CTRL XFER (STP)
- 43/BT-1EA1, BUS TIE BKR BT-1EA1 CTRL XFER (STP)
- 43/T1EB1, XFMR BKR T1EB1 CTRL XFER (STP)
- 43/1EB1-1, INCOMING BRK 1EB1-1 CTRL XFER (STP)
- 43/T1EB3, XFMR BKR T1EB3 CTRL XFER (STP)
- 43/1EB3-1, INCOMING BRK 1EB3-1 CTRL XFER (STP)
- 43/BT-1EB13, BUS TIE BKR BT-1EB13 CTRL XFER (STP)

☐ 46. Transfer the following Train B controls from CR to HSP:

- 43-1EA2-1, BKR 1EA2-1 CTRL XFER (RSP)
- 43-1EA2-2, BKR 1EA2-2 CTRL XFER (RSP)

47. IF local control of the Diesel Generators is desired, THEN perform the following:

☐ a. Ensure 1-HS-4393FL, DG 1 CLR SSW RET VLV (RSP) - OPEN.

☐ b. Transfer 1-HS-4393FT, DG 1 CLR SSW RET VLV CTRL XFER (STP) from CR to HSP.

☐ c. Ensure both Diesel Generators running per Attachment 11.

☐ d. WHEN both Diesel Generators are running, THEN transfer following controls from CR to HSP:

- 43/1EG1, DG 1 BKR 1EG1 CTRL XFER (STP)
- 43/1EG2, DG 2 BKR 1EG2 CTRL XFER (RSP)

☐ 48. Ensure local control of Emergency Fan Cooler Units per Attachment 8.

☐ 49. At the discretion of the Shift Manager, ensure the handswitch or controller is properly positioned prior to transfer AND transfer remaining switches to HSP position.

2.3 Operator Actions

NOTE:
- RCS indicated temperature response is slow due to the slow response time of the strap on RTD's.
- Steam pressure converted to Tsat/Tcold is the best indication of temperature and temperature change.

☐ 50. Monitor parameters on Attachment 7, AND record every thirty (30) minutes.

NOTE: The Unit is in a stable Hot Standby condition with control established at the Remote Shutdown Panel. Hot Standby may be maintained as long as there is sufficient water in the Condensate Storage Tank to cool down the plant to Cold Shutdown.

☐ 51. Monitor CST LVL AND refer to TDM-502A:

- 1-LI-2478B, CST LVL (RSP)
- 1-LI-2479B, CST LVL (RSP)

NOTE:
- Tripping RCP 2 & 3 decreases heat transfer through SG 2 & SG 3. Adjustment of AFW flow and SG Atmos Rlf valves may be necessary.
- STA-124 EPE required for breaker operations is staged in the STA-124 clothing locker.

☐ 52. Locally open RCPs 2 and 3 breakers (TB 810 Rm 1-031):

- 1A2/8/BKR, 1PCPX2, REACTOR COOLANT PUMP 1-02 MOTOR BREAKER
- 1A3/2/BKR, 1PCPX3, REACTOR COOLANT PUMP 1-03 MOTOR BREAKER

☐ 53. Verify RCPs 2 and 3 NOT running:

- 1-ZL-PCPX2F, RCP 2 - (OFF)
- 1-ZL-PCPX3F, RCP 3 - (OFF)

☐ 54. Maintain following limits while maintaining Hot Standby:

- PRZR PRESS - 2200 psig - 2300 psig
- Actual PRZR LVL - 25% - 50%
- Actual SG LVL - 84% - 92%
- SG PRESS - 800 psig - 1150 psig

2.3 Operator Actions

> NOTE:
> - IPO-009A may be referred to for general guidance on securing the secondary plant.
> - SDM calculations need not all be completed prior to continuing.

☐ 55. Initiate a Shutdown Margin (SDM) Calculation per OPT-301 (uncorrected minimum Boron Concentration) for the following temperature plateaus while continuing:

- 500°F Required boron concentration ________ ppm
- 400°F Required boron concentration ________ ppm
- 300°F Required boron concentration ________ ppm
- 200°F Required boron concentration ________ ppm

☐ 56. WHEN plant cooldown is desired, THEN continue this procedure.

☐ 57. Borate to desired temperature plateau uncorrected minimum boron concentration per OPT-301, using Attachment 12 of this procedure.

> CAUTION:
> - Low steam line pressure SI may occur at 605 psig if not blocked.
> - Low pressurizer pressure SI may occur at 1820 psig if not blocked.

> NOTE: When RCS pressure is approximately 1900 psig, SI may be blocked by I&C per Attachment 6.

☐ 58. During cooldown, maintain the following limits:

- Subcooling >65°F (Attachment 13)
- Actual PRZR LVL - 25% to 50% (Attachment 17)
- Actual SG LVL - 84% to 92% (Attachment 16)

☐ 59. Ensure the boration required to establish adequate SDM for 400°F has been completed.

2.3 Operator Actions

> NOTE:
> - RCS indicated temperature response is slow due to the slow response time of the strap on RTDs.
> - Cooldown shall NOT exceed 100°F in any one hour period (Tech Spec Limit).

☐ 60. Throttle the SG Atmos Rlf valves to establish a cooldown rate of approximately 20°F/hr:

- 1-HC-2325, SG 1 ATMOS RLF VLV CTRL (RSP)
- 1-HC-2326, SG 2 ATMOS RLF VLV CTRL (RSP)
- 1-HC-2327, SG 3 ATMOS RLF VLV CTRL (RSP)
- 1-HC-2328, SG 4 ATMOS RLF VLV CTRL (RSP)

> CAUTION: IF RCS pressure increases above 1960 psig after SI has been blocked, SI must be re-blocked.

☐ 61. WHEN RCS pressure reaches approximately 1900 psig on 1-PI-455B PRZR PRESS, THEN perform the following:

- Maintain PRZR PRESS approximately 1900 psig until SI is blocked.
- Notify I&C to block the low pressurizer pressure AND low steam line pressure SI signals per Attachment 6.

☐ 62. IF a cooldown below 400°F is necessary, THEN ensure boration required to establish adequate SDM for 300°F has been completed.

2.3 Operator Actions

63. WHEN RCS pressure is less than 1000 psig, THEN CLOSE the Accumulator isolation valves by one of the following methods:

☐ a. Have Emergency Repair and Damage Control Team CLOSE the Accumulator isolation valves per Attachment 19.

OR

b. Perform the following to locally CLOSE the Accumulator isolation valves:

1) Ensure the following breakers (SFGD 810 Rm 1-083) - OPEN:

☐ • 1EB3-2/6F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 1

☐ • 1EB3-2/6F/BKR-2, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 2

☐ • 1EB3-2/6M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 1

☐ • 1EB3-2/6M/BKR-2, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 2

2) Ensure the following breakers (SFGD 852 Rm 1-103) - OPEN:

☐ • 1EB4-2/5F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 1

☐ • 1EB4-2/5F/BKR-2, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 2

☐ • 1EB4-2/5M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-04 INJECT VALVE 1-8808D MOTOR BREAKER 1

☐ • 1EB4-2/5M/BKR-2, SAFETY INJECTION ACCUMULATOR 1-04 INJECT VALVE 1-8808D MOTOR BREAKER 2

☐ 3) Make a Containment entry per STA-620.

4) Locally CLOSE the following valves:

☐ • 1-8808A, SI ACCUM 1-01 INJ VLV (CNTMT 832)

☐ • 1-8808B, SI ACCUM 1-02 INJ VLV (CNTMT 832)

☐ • 1-8808C, SI ACCUM 1-03 INJ VLV (CNTMT 832)

☐ • 1-8808D, SI ACCUM 1-04 INJ VLV (CNTMT 842)

☐ 64. Transfer control of 1-8702A per Attachment 14.

2.3 Operator Actions

65. WHEN RCS temperature is less than 350°F, THEN rack out Safety Injection Pump breakers:

- ☐ • 1EA1/10/BKR, 1APSI1, SAFETY INJECTION PUMP 1-01 MOTOR BREAKER
- ☐ • 1EA2/9/BKR, 1APSI2, SAFETY INJECTION PUMP 1-02 MOTOR BREAKER

66. Place RHR system in recirculation to the RWST as follows:

☐ a. Open 1EB3-1/7C/BKR, RHR HEAT EXCHANGER 1-01 CCW RETURN VALVE 4572 MOTOR BREAKER (SFGD 790).

☐ b. Locally open 1-HV-4572, RHR HX 1-01 CCW RET VLV (SFGD 790 Rm 1-070 Corr).

NOTE:	Valve 1-8717 is normally locked closed.

☐ c. Open 1-8717, U1 RHR PMP DISCH TO RWST ISOL VLV, (SFGD 800 Rm 1-076 Trn A ECCS Vlv Rm).

[R] ☐ d. Vent the RHRP Seal Cooler by opening 1RH-0025, RHR PMP 1-01 SEAL CLR VNT VLV, (SFGD 773 Rm 1-053) for a minimum of 60 seconds.

☐ e. Ensure control of 1-HCV-0606 and 1-FCV-0618 transferred per Attachment 10.

NOTE:	1-HC-606A, RHR HX 1 FLO CTRL controller works differently than controllers for SG Atmos Rlf vlvs and 1-HC-618. The demand meter reads actual demand, but the knob must be turned in clockwise direction to close the valve (increase direction).

☐ f. Adjust 1-HC-606A, RHR HX 1 FLO CTRL to 20% demand.

☐ g. Adjust 1-HC-618, RHR HX 1 BYP FLO CTRL to 20% demand.

☐ h. IF operator available, THEN locally monitor RHR flow during pump start on 1-FIS-0610, RESIDUAL HEAT REMOVAL PUMP 1-01 DISCHARGE FLOW INDICATING SWITCH (SFGD 773 CS Pmp 1-01 & 1-03 Rm) (range is only 0-1500 gpm).

☐ i. Transfer 43/1-APRH1F, RHRP 1 CTRL XFER (STP) from CR to HSP.

☐ j. Start 1/1-APRH1F, RHRP 1 (RSP) AND run for approximately 10 minutes.

☐ k. Notify Chemistry to sample and determine boron concentration of TRN A RHR.

☐ l. Contact I&C to monitor temperature outlet of RHR 1-01 (Monitoring may be performed with a hand held pyrometer at 1-TW-4564).

"Step continued next page"

2.3 Operator Actions

> NOTE: Attachment 15, contains steps for installing test equipment to inject a signal to the current to pneumatic (I/P) converter for 1-HCV-0128, RHR LTDN FLO CTRL. This allows local control of this valve.

66.

☐ m. Contact I&C to hook up a Transmation (4-20 MA) supply to 1-HCY-0128 (SFGD 810 Rm 1-080 Ltdn Hx Rm) per Attachment 15.

☐ n. Stop 1/1-APRH1F, RHRP 1

☐ o. Close 1-8717, U1 RHR PMP DISCH TO RWST ISOL VLV (SFGD 800 Trn A ECCS Vlv Rm).

☐ 67. IF cooldown must be continued to cold shutdown, THEN ensure boration required to establish adequate SDM for 200°F has been completed.

[C]

> CAUTION: Valves 1-8812A, 1-8702A, and 1-8701A must be operated in the sequence specified to prevent aligning RHR to the RCS without isolating the RWST. All RHR suction valve interlocks are bypassed when operated locally or from the RSP.

68. WHEN RCS temperature is less than 350°F AND RCS pressure is approximately 350 psig (325 psig to 375 psig), THEN align the RHR system for recirc cooling as follows:

☐ a. Open 1EB1-1/1J/DSW, RHR PUMP 1-01 MINIMUM FLOW VALVE 0610 MOTOR FUSED SWITCH (SFGD 810 Rm 1-083)

☐ b. Open 1EB3-1/1G/BKR, RWST TO RESIDUAL HEAT REMOVAL PMP 1-01 SUCT VLV 1-8812A MOTOR BREAKER (SFGD 790 Rm 1-070)

☐ c. Locally close 1-8812A, RWST 1-01 TO RHR PMP 1-01 SUCT VLV (SFGD 790 Corr).

[R] ☐ d. Locally open 1-FCV-0610, RHR PMP 1-01 MINIFLO VLV (SFGD 790 Trn A ECCS Vlv Rm).

e. Close the following breakers: (SFGD 810 Rm 1-083).

- ☐ 1EB3-2/9G/BKR-1, RHR PMP 1-01 HL 1-01 RECIRC OMB ISOL VLV 1-8701A MOTOR BREAKER 1
- ☐ 1EB3-2/9G/BKR-2, RHR PMP 1-01 HL 1-01 RECIRC OMB ISOL VLV 1-8701A MOTOR BREAKER 2

"Step continued next page"

2.3 Operator Actions

68.

f. Close the following breakers: (SFGD 810 Rm 1-083).

- ☐ • 1EB3-2/8RF/BKR-1, RHR PMP 1-01 HL 1-01 RECIRC IMB ISOL VALVE 1-8702A ALT MOT BREAKER 1
- ☐ • 1EB3-2/8RF/BKR-2, RHR PMP 1-01 HL 1-01 RECIRC IMB ISOL VALVE 1-8702A ALT MOT BREAKER 2

[C]

> NOTE: 1-8812A should be fully closed prior to opening 1-8702A OR 1-8701A.

☐ g. Open 1-8702A with switch 1/1-8702AL on 1EB3-2/8RF/BKR.

☐ h. Ensure 43/1-8701AF, RHRP 1 HL RECIRC ISOL VLV CTRL XFER (STP) has been transferred from CR to HSP.

☐ i. Open 1/1-8701AF, RHRP 1 HL RECIRC ISOL VLV.

☐ j. Ensure control of 1-HCV-0606 and 1-FCV-0618 transferred per Attachment 10.

> NOTE: 1-HC-606A, RHR HX 1 FLO CTRL controller works differently than controllers for SG Atmos Rlf vlvs and 1-HC-618. The demand meter reads actual demand, but the knob must be turned in clockwise direction to close the valve (increase direction).

☐ k. Close 1-HC-606A, RHR HX 1 FLO CTRL.

☐ l. Close 1-HC-618, RHR HX 1 BYP FLO CTRL.

☐ m. Locally ensure 1-HV-4572, RHR HX 1 CCW RET VLV (SFGD 790 Rm 1-070 Corr) - OPEN.

☐ n. Ensure 43/1-APRH1F, RHRP 1 CTRL XFER (STP) is in HSP.

☐ o. IF operator available, THEN locally monitor RHR flow during pump start on 1-FIS-0610, RHR PUMP 1-01 MINIFLOW (SFGD 773 Rm 1-054 CS Pmp 1-01 & 1-03 Rm) (the range on 1-FIS-610 is only 0-1500 gpm).

☐ p. Start 1/1-APRH1F, RHRP 1 (RSP)

☐ q. Slowly open 1-HC-618, RHR HX 1 BYP FLO CTRL approximately 60%.

[R] ☐ r. Locally close 1-FCV-0610, RHR PMP 1-01 MINIFLOW VLV (SFGD 790 Trn A ECCS Vlv Rm).

"Step continued next page"

2.3 Operator Actions

> NOTE: Cooldown shall NOT exceed 100°F in any one hour period (Tech Spec Limit).

68.

☐ s. Slowly open 1-HC-606A, RHR HX 1 FLO CTRL, WHILE closing 1-HC-618, RHR HX 1 BYP FLO CTRL to establish a cooldown rate of approximately 20°F/hr.

☐ t. Ensure CCW outlet temperature of RHR HX 1-01 does not exceed 200°F.

> NOTE:
> - Completion of boration is desired prior to stopping RCPs to minimize boron stratification.
> - STA-124 EPE required for breaker operations is staged in the STA-124 clothing locker.

69. Locally open RCPs 1 and 4 breakers (TB 810 Rm 1-031):

☐ • 1A1/8/BKR, 1PCPX1, REACTOR COOLANT PUMP 1-01 MOTOR BREAKER

☐ • 1A4/2/BKR, 1PCPX4, REACTOR COOLANT PUMP 1-04 MOTOR BREAKER

70. Verify RCPs 1 and 4 NOT running:

☐ • 1-ZL-PCPX1F, RCP 1 - (OFF)

☐ • 1-ZL-PCPX4F, RCP 4 - (OFF)

☐ 71. Maintain RCS pressure between 300 psig to 400 psig using PRZR heaters and PRZR PORVs.

72. IF it is desired to establish letdown flow through CVCS to REHUT, THEN perform the following:

[R] ☐ a. Locally close 1-8408A, U1 LTDN PRESS CTRL UPSTRM ISOL VLV OR 1-8408B, U1 LTDN PRESS CTRL DNSTRM ISOL VLV (SFGD 810 Ltdn HX Valve Rm).

☐ b. Locally verify 1-LCV-0112A, VCT 1-01 LVL CTRL VLV is in REHUT, (valve stem fully down), (SFGD 832, VCT Vlv Rm).

☐ c. Have I&C open 1-HCV-0128, RHR LTDN FLO CTRL with installed test equipment.

☐ d. Ensure REHUT can accept expected letdown flow for several hours.

☐ e. Locally open 1RH-8734A-RO, RHR HX 1-01 TO CVCS LTDN ISOL VLV RMT OPER (SFGD 800 Rm 1-076).

"Step continued next page"

2.3 Operator Actions

72.

☐ f. Dispatch an Operator with a portable two-way radio to SFGD 822 Rm 1-086 Ltdn Remote Valve Op Room to locally position 1CS-8409-RO, U1 LTDN HX OUT PRESS CTRL VLV BYP VLV RMT OPER.

☐ g. Direct the Operator to slowly open 1CS-8409-RO as necessary to regulate letdown flow.

73. WHEN RCS Temperature is less than 250°F, THEN perform the following:

a. Close SG ATMOS RLF VLVs:

☐ • 1-HC-2325, SG 1 ATMOS RLF VLV CTRL (RSP)

☐ • 1-HC-2326, SG 2 ATMOS RLF VLV CTRL (RSP)

☐ • 1-HC-2327, SG 3 ATMOS RLF VLV CTRL (RSP)

☐ • 1-HC-2328, SG 4 ATMOS RLF VLV CTRL (RSP)

b. Close MD AFWP FLO CTRL VLVs:

☐ • 1-FK-2453C, MD AFWP 1 FLO CTRL (RSP)

☐ • 1-FK-2453D, MD AFWP 1 FLO CTRL (RSP)

☐ • 1-FK-2454C, MD AFWP 2 FLO CTRL (RSP)

☐ • 1-FK-2454D, MD AFWP 2 FLO CTRL (RSP)

c. Stop Motor Driven Auxiliary Feedwater Pumps:

☐ • 1-HS-2450C, MD AFWP 1 (RSP)

☐ • 1-HS-2451C, MD AFWP 2 (RSP)

2.3 Operator Actions

NOTE:	STA-124 EPE required for breaker operations is staged in the STA-124 clothing locker.

74. WHEN RCS temperature is less than 200°F, THEN rack out the Containment Spray Pump breakers:

- ☐ • 1EA1/8/BKR, 1APCS1, CONTAINMENT SPRAY PUMP 1-01 MOTOR BREAKER (SFGD 810 Rm 1-083)
- ☐ • 1EA2/10/BKR, 1APCS2, CONTAINMENT SPRAY PUMP 1-02 MOTOR BREAKER (SFGD 852 Rm 1-103)
- ☐ • 1EA1/6/BKR, 1APCS3, CONTAINMENT SPRAY PUMP 1-03 MOTOR BREAKER (SFGD 810 Rm 1-083)
- ☐ • 1EA2/11/BKR, 1APCS4, CONTAINMENT SPRAY PUMP 1-04 MOTOR BREAKER (SFGD 852 Rm 1-103)

☐ 75. Continue with cooldown as required OR maintain control of plant system from RSP and locally until access to Control Room is regained.

☐ 76. WHEN access to control room is regained AND Emergency Coordinator has decided to reestablish control from the Control Room, THEN follow guidelines in Attachment 18.

END OF SECTION

3.0 REFERENCES

3.1 Technical Specifications

- 3.4.3 RCS Pressure and Temperature (P/T) Limits

3.2 CPNPP Procedures

- Commitments 27195, 27201, 27202, 27203, 27198 Loss of HP Injection & Charging From Gas Intrusion (SOER 97-01)
- Commitment 04564, Precaution Avoid Manual Pressurizer Heater Operation (FSAR)
- Commitment 06460, Neutron Lev. & Cont Rod Position Verified Before Evac of Control Room
- Commitment 22880, Establish Cold Shutdown (FSAR) |
- Commitment 23397, Response to NRC INSRPT NO.(50-445/8937, 50-446/8937)
- Commitment 4163173, IERL1 11-2, Fukushima Daiichi Nuclear Station Spent Fuel Pool Loss of Cooling and Makeup (Recommendation 4)
- ABN-909, Spent Fuel Pool/Refueling Cavity Malfunction
- ALM-0701, Alarm Procedure Spent Fuel Pool Panel
- EPP-201, Assessment of Emergency Action Levels, Emergency Classification and Plan Activation
- IPO-009A, Plant Equipment Shutdown Following A Trip
- OPT-301, Reactor Shutdown Margin Verification
- STA-603, Control of Station Radioactive Effluents
- STA-620, Containment Entry
- STA-919, CPNPP Safety-Security Interface Requirements

3.3 Applicable Drawings

- Electrical E1-0001
- Electrical E1-0062 Sheet 16
- Electrical E1-0062 Sheet 17
- Electrical E1-0062 Sheet 18
- Electrical E1-0062 Sheet 19
- Mechanical M1-0202
- Mechanical M1-0202-2
- Mechanical M1-0206
- Mechanical M1-0215
- Mechanical M1-0228
- Mechanical M1-0229
- Mechanical M1-0233
- Mechanical M1-0234
- Mechanical M1-0239
- Mechanical M1-0250
- Mechanical M1-0251
- Mechanical M1-0253
- Mechanical M1-0255
- Mechanical M1-0260
- Mechanical M1-0261
- Mechanical M1-0262
- Mechanical M1-0263
- Mechanical M1-0302
- Mechanical M1-0303
- Mechanical M1-0303-01

- Mechanical M1-0311
- Electrical E1-0172 Sheet 10
- Electrical E1-0172 Sheet 14
- Electrical E1-0172 Sheet 16
- Electrical E1-0172 Sheet 17
- Electrical E1-0053 Sheet 41
- Electrical E1-0053 Sheet 42
- Electrical E1-0053 Sheet 45
- Electrical E1-0053 Sheet 46
- Electrical E1-0053 Sheet 51
- Electrical E1-0053 Sheet 52
- Electrical E1-0053 Sheet 53
- Electrical E1-0053 Sheet 54
- Electrical E1-0056 Sheet 55
- Electrical E1-0056 Sheet 56
- Electrical E1-0056 Sheet 57
- Electrical E1-0056 Sheet 58
- Electrical E1-0056 Sheet 60
- Electrical E1-0056 Sheet 61

3.4 Vendors Manuals

None

3.5 Other References

- CPSES FSAR Section 7.4.1.3.2
- CPSES FSAR Section 7.4.2.2
- LRF 90-1283 (STA-618)

4.0 ATTACHMENTS

Attachment 1, Instrumentation and Controls Available at the RSP

Attachment 2, Transfer Switches Located at the Shutdown Transfer Panel (STP)

Attachment 3, Natural Circulation Verification

Attachment 4, Charging Pump Suction Transfer to the RWST and RCS Dilution Path Isolation

Attachment 5, 6.9KV Safeguards Bus Loading Sequence

Attachment 6, SI Block from the Cable Spread Room

Attachment 7, RCS Pressure/Temperature Verification

Attachment 8, Emergency Fan Cooler Units

Attachment 9, Control Transfer of Steam Generator Atmospheric Relief Valves

Attachment 10, Control Transfer of RC LOOP 4 PRZR SPR VLV (1-PCV-0455A), 1-HCV-0606 and 1-FCV-0618

Attachment 11, Local Start of Diesel Generators

Attachment 12, Boration

Attachment 13, RCS Pressure - Temperature Limit

Attachment 14, Control Transfer of 1-8702A

Attachment 15, Local Control of 1-HCV-0128, RHR LTDN FLO CTRL

Attachment 16, SG Level Temperature Correction

Attachment 17, PRZR LVL Temperature Correction

Attachment 18, Transfer of Control to the Main Control Room

Attachment 19, Closing Accumulator Isolation Valves from the MCC

Attachment 20, Supervisor Checklist

ATTACHMENT 1
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INSTRUMENTATION AND CONTROLS AVAILABLE AT THE RSP

Device No.	Nomenclature
Electrical	
Train A	
A-1EA1-1L	BKR 1EA1-1 CURRENT
A-1EA1-2L	BKR 1EA1-2 CURRENT
A-1EG1-1L	DG 1 CURRENT
F-1EA1-L	BUS 1EA1 FREQ
V-1EA1-L	BUS 1EA1 VOLT
CS-BT1EA1-L	BUS TIE BKR BT-1EA1
CS-BT1EB13-L	BUS TIE BKR BT-1EB13
CS-T1EB1-L	XFMR BKR T1EB1
CS-T1EB3-L	XFMR BKR T1EB3
CS-1EA1-1L	INCOMING BKR 1EA1-1
CS-1EA1-2L	INCOMING BKR 1EA1-2
CS-1EB1-1L	INCOMING BKR 1EB1-1
CS-1EB3-1L	INCOMING BKR 1EB3-1
CS-1EG1-L	DG 1 BKR 1EG1
Train B	
A-1EA2-1L	BKR 1EA2-1 CURRENT
A-1EA2-2L	BKR 1EA2-2 CURRENT
A-1EG2-L	DG 2 CURRENT
F-1EA2-L	BUS 1EA2 FREQ
V-1EA2-L	BUS 1EA2 VOLT

ATTACHMENT 1
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INSTRUMENTATION AND CONTROLS AVAILABLE AT THE RSP

Device No.	Nomenclature
Electrical	
Train B Continued	
CS-1EG2-L	DG 2 BKR 1EG2
CS-1EA2-1L	INCOMING BKR 1EA2-1
CS-1EA2-2L	INCOMING BKR 1EA2-2
43-1EA2-1	BKR 1EA2-2 CTRL XFER
43-1EA2-2	BKR 1EA2-2 CTRL XFER
43-1EG2	DG 2 BKR 1EG2 CTRL XFER
Station Service Water and Component Cooling Water	
Train A	
1-FI-4258B	SSWP 1 DISCH FLO
1-HS-4250C	SSWP 1
1-HS-4286FL	SSWP 1 DISCH VLV
1-HS-4393FL	DG 1 CLR SSW RET VLV
1-HS-4514FL	SFGD LOOP CCW SPLY VLV
1-HS-4518C	CCWP 1
1-HS-4524FL	NON-SFGD LOOP CCW RET VLV
1-HS-4526FL	NON-SFGD LOOP CCW SPLY VLV
1-HS-4699FL	RCP/THBR CLR CCW SPLY ISOL VLV
1-HS-4701FL	RCP CLR CCW RET ISOL VLV
1-PI-4252B	SSWP 1 DISCH PRESS

INSTRUMENTATION AND CONTROLS AVAILABLE AT THE RSP

Device No.	Nomenclature
Train B	
1-FI-4259B	SSWP 2 DISCH FLO
1-HS-4251B	SSWP 2 CTRL XFER
1-HS-4251C	SSWP 2
1-HS-4519B	CCWP 2 CTRL XFER
1-HS-4519C	CCWP 2
1-PI-4253B	SSWP 2 DISCH PRESS
Auxiliary Feedwater	
1-FI-2463B	SG 1 AFW FLO
1-FI-2463D	SG 1 AFW FLO
1-FI-2464B	SG 2 AFW FLO
1-FI-2464D	SG 2 AFW FLO
1-FI-2465B	SG 3 AFW FLO
1-FI-2465D	SG 3 AFW FLO
1-FI-2466B	SG 4 AFW FLO
1-FI-2466D	SG 4 AFW FLO
1-FK-2453C	MD AFWP 1 SG 1 FLO CTRL
1-FK-2453D	MD AFWP 1 SG 2 FLO CTRL
1-FK-2454C	MD AFWP 2 SG 3 FLO CTRL
1-FK-2454D	MD AFWP 2 SG 4 FLO CTRL
1-FK-2459B	TD AFWP SG 1 FLO CTRL
1-FK-2460B	TD AFWP SG 2 FLO CTRL

ATTACHMENT 1
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INSTRUMENTATION AND CONTROLS AVAILABLE AT THE RSP

Device No.	Nomenclature
1-FK-2461B	TD AFWP SG 3 FLO CTRL
1-FK-2462B	TD AFWP SG 4 FLO CTRL
1-HS-2450C	MD AFWP 1
1-HS-2451B	MD AFWP 2 CTRL XFER
1-HS-2451C	MD AFWP 2
1-HS-2452C	AFWPT MSL 4 SPLY VLV
1-HS-2452D	AFWPT MSL 1 SPLY VLV CTRL XFER
1-HS-2452E	AFWPT MSL 1 SPLY VLV
1-HS-2456FL	MD AFWP 1 RECIRC VLV
1-LI-2478B	CST LVL
1-LI-2479B	CST LVL
1-PI-2453B	MD AFWP 1 DISCH PRESS
1-PI-2454B	MD AFWP 2 DISCH PRESS
1-PI-2455B	TD AFWP DISCH PRESS
1-PI-2475B	MD AFWP 1 SUCT PRESS
1-PI-2476B	MD AFWP 2 SUCT PRESS
1-PI-2477B	TD AFWP SUCT PRESS
1-SI-2452B	AFWPT SPD
1-SK-2452B	AFWPT SPD CTRL
1-ZL-2453C	MD AFWP 1 SG 1 FLO CTRL VLV
1-ZL-2453D	MD AFWP 1 SG 2 FLO CTRL VLV
1-ZL-2454C	MD AFWP 2 SG 3 FLO CTRL VLV

ATTACHMENT 1
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INSTRUMENTATION AND CONTROLS AVAILABLE AT THE RSP

Device No.	Nomenclature
1-ZL-2454D	MD AFWP 2 SG 4 FLO CTRL VLV
1-ZL-2459B	TD AFWP SG 1 FLO CTRL VLV
1-ZL-2460B	TD AFWP SG 2 FLO CTRL VLV
1-ZL-2461B	TD AFWP SG 3 FLO CTRL VLV
1-ZL-2462B	TD AFWP SG 4 FLO CTRL VLV
1-ZL-2475B	MD AFWP 1 SUCT PRESS LO
1-ZL-2476B	MD AFWP 2 SUCT PRESS LO
Steam Generators	
1-HC-2325	SG 1 ATMOS RLF VLV CTRL
1-HC-2326	SG 2 ATMOS RLF VLV CTRL
1-HC-2327	SG 3 ATMOS RLF VLV CTRL
1-HC-2328	SG 4 ATMOS RLF VLV CTRL
1-HS-2333FL	MSIV 1
1-HS-2334FL	MSIV 2
1-HS-2335FL	MSIV 3
1-HS-2336FL	MSIV 4
1-HS-5180F	SG BLDN HX OUT PRESS CTRL VLV
1-LI-501A	SG 1 LVL (WR)
1-LI-502A	SG 2 LVL (WR)
1-LI-503A	SG 3 LVL (WR)
1-LI-504A	SG 4 LVL (WR)
1-PI-514B	SG 1 PRESS

ATTACHMENT 1
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INSTRUMENTATION AND CONTROLS AVAILABLE AT THE RSP

Device No.	Nomenclature
1-PI-524B	SG 2 PRESS
1-PI-534B	SG 3 PRESS
1-PI-544B	SG 4 PRESS
RCS and CVCS	
1-FI-121B	CHRG FLO
1-FI-132B	LTDN FLO
1-FI-183B	EMER BORATE FLO
1-FK-121A	CHRG FLO CTRL
1-HC-455C	RC LOOP 4 PRZR SPR VLV CTRL
1-LI-459B	PRZR LVL
1-LI-460B	PRZR LVL
1-PI-455B	PRZR PRESS
1-ZL-PCPX1F	RCP 1
1-ZL-PCPX2F	RCP 2
1-ZL-PCPX3F	RCP 3
1-ZL-PCPX4F	RCP 4
1-ZL-455BF	RC LOOP 1 PRZR SPR VLV
1-ZL-455CF	RC LOOP 4 PRZR SPR VLV
1/1-APBA1L	BA XFER PMP 1
1/1-APBA2L	BA XFER PMP 2
1/1-APCH1L	CCP 1
1/1-APCH2L	CCP 2

ATTACHMENT 1
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INSTRUMENTATION AND CONTROLS AVAILABLE AT THE RSP

Device No.	Nomenclature
1/1-PCPR1L	PRZR HTR BACKUP GROUP A
1/1-PCPR2L	PRZR HTR BACKUP GROUP B
1/1-TCV-129L	LTDN DIVERT VLV
1/1-455AFL	PRZR PORV
1/1-456FL	PRZR PORV
1/1-8104L	EMER BORATE VLV
1/1-8106FL	CHRG PMP TO RCS ISOL VLV
1/1-8110FL	CCP 1 & 2 MINI FLO VLV
1/1-8149AL	LTDN ORIFICE ISOL VLV (45 GPM)
1/1-8149BL	LTDN ORIFICE ISOL VLV (75 GPM)
1/1-8149CL	LTDN ORIFICE ISOL VLV (75 GPM)
1/1-8153FL	XS LTDN ISOL VLV
1/1-8801AF	CCP SI ISOL VLV
43/1-APBA2L	BA XFER PMP 2 CTRL XFER
43/1-APCH2L	CCP 2 CTRL XFER
43/1-PCPR2L	PRZR HTR CTRL XFER
43/1-456FT	PRZR PORV CTRL XFER
43/1-8104L	EMER BORATE VLV CTRL XFER
43/1-8153FT	XS LTDN ISOL VLV CTRL XFER

ATTACHMENT 1
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INSTRUMENTATION AND CONTROLS AVAILABLE AT THE RSP

Device No.	Nomenclature
1-TR-410F/420F/ 413F/423F	R (Pt. 1): CL 1 TEMP °F V (Pt. 2): CL 2 TEMP °F G (Pt. 3): HL 1 TEMP °F BLK (Pt. 4): HL 2 TEMP °F
1-TR-430F/440F/ 433F/443F	R (Pt. 1): CL 3 TEMP °F V (Pt. 2): CL 4 TEMP °F G (Pt. 3): HL 3 TEMP °F BLK (Pt. 4): HL 4 TEMP °F
1-NI-50A-3	NEUT FLUX SR
1-NI-50B-3	NEUT FLUX SR
RHR	
1-HC-606A	RHR HX 1 FLO CTRL
1-HC-618	RHR HX 1 BYP FLO CTRL
1/1-APRH1F	RHRP 1
1/1-8701AF	RHRP 1 HL RECIRC ISOL VLV
1/1-8701BF	RHRP 2 HL RECIRC ISOL VLV
Misc	
1-HS-5405C	CNTMT FN CLR FN 1
1-HS-5409B	CNTMT FN CLR FN 2 CTRL XFER
1-HS-5409C	CNTMT FN CLR FN 2
1-HS-5413C	CNTMT FN CLR FN 3
1-HS-5417B	CNTMT FN 4 CTRL XFER
1-HS-5417C	CNTMT FN CLR FN 4
1-HS-6700FL	SFTY CH WTR RECIRC PMP 5

ATTACHMENT 2
PAGE 1 OF 2

TRANSFER SWITCHES LOCATED ON THE SHUTDOWN TRANSFER PANEL (STP)

Switch No.	Nomenclature
1-HS-2333FT	MSIV 1 CTRL XFER
1-HS-2334FT	MSIV 2 CTRL XFER
1-HS-2335FT	MSIV 3 CTRL XFER
1-HS-2336FT	MSIV 4 CTRL XFER
1-HS-2450B	MD AFWP 1 CTRL XFER
1-HS-2452B	AFWPT MSL 4 SPLY VLV CTRL XFER
1-HS-2453AF	MD AFWP 1 SG 1 FLO CTRL CTRL XFER
1-HS-2453BF	MD AFWP 1 SG 2 FLO CTRL CTRL XFER
1-HS-2456FT	MD AFWP 1 RECIRC VLV CTRL XFER
1-HS-4250B	SSWP 1 CTRL XFER
1-HS-4286FT	SSWP 1 DISCH VLV CTRL XFER
1-HS-4393FT	DG 1 CLR SSW RET VLV CTRL XFER
1-HS-4514FT	SFGD LOOP CCW SPLY VLV CTRL XFER
1-HS-4518B	CCWP 1 CTRL XFER
1-HS-4524FT	NON-SFGD LOOP CCW RET VLV CTRL XFER
1-HS-4526FT	NON-SFGD LOOP CCW SPLY VLV CTRL XFER
1-HS-4699FT	RCP/THBR CLR CCW SPLY ISOL VLV CTRL XFER
1-HS-4701FT	RCP CLR CCW RET ISOL VLV CTRL XFER
1-HS-5405B	CNTMT FN CLR FN 1 CTRL XFER
1-HS-5413B	CNTMT FN CLR FN 3 CTRL XFER
1-HS-6700FT	SFTY CH WTR RECIRC PMP 5 CTRL XFER
1-HS-6710B	SFTY CH WTR CHLR BYP LCKOUT
43/BT-1EA1	BUS TIE BKR BT-1EA1 CTRL XFER
43/BT-1EB13	BUS TIE BKR BT-1EB13 CTRL XFER
43/T1EB1	XFMR BKR T1EB1 CTRL XFER
43/T1EB3	XFMR BKR T1EB3 CTRL XFER
43/1-APBA1L	BA XFER PMP 1 CTRL XFER
43/1-APCH1L	CCP 1 CTRL XFER

ATTACHMENT 2
PAGE 2 OF 2

TRANSFER SWITCHES LOCATED ON THE SHUTDOWN TRANSFER PANEL (STP)

Switch No.	Nomenclature
43/1-APRH1F	RHRP 1 CTRL XFER
43/1-PCPR1L	PRZR HTR BACKUP GROUP A CTRL XFER
43/1-TCV-129	LTDN DIVERT VLV CTRL XFER
43/1-121FT	CHRG FLO CTRL CTRL XFER
43/1-455AFT	PRZR PORV CTRL XFER
43/1-8106FT	CHRG PMP TO RCS ISOL VLV CTRL XFER
43/1-8110FT	CCP 1 & 2 MINIFLO VLV CTRL XFER
43/1-8149AL	LTDN ORIFICE ISOL VLV (45 GPM) CTRL XFER
43/1-8149BL	LTDN ORIFICE ISOL VLV (75 GPM) CTRL XFER
43/1-8149CL	LTDN ORIFICE ISOL VLV (75 GPM) CTRL XFER
43/1-8701AF	RHRP 1 HL RECIRC ISOL VLV CTRL XFER
43/1-8701BF	RHRP 2 HL RECIRC ISOL VLV CTRL XFER
43/1-8801AF	CCP SI ISOL VLV CTRL XFER
43/1EA1-1	INCOMING BKR 1EA1-1 CTRL XFER
43/1EA1-2	INCOMING BKR 1EA1-2 CTRL XFER
43/1EB1-1	INCOMING BKR 1EB1-1 CTRL XFER
43/1EB3-1	INCOMING BKR 1EB3-1 CTRL XFER
43/1EG1	DG 1 BKR 1EG1 CTRL XFER

ATTACHMENT 3
PAGE 1 OF 1

NATURAL CIRCULATION VERIFICATION

The following conditions support or indicate natural circulation flow:

- RCS Subcooling - GREATER THAN 25°F
- SG pressures - STABLE OR DECREASING
- RCS hot leg temperatures - STABLE OR DECREASING
- RCS cold leg temperature - AT SATURATION TEMPERATURE FOR SG PRESSURE

ATTACHMENT 4
PAGE 1 OF 2

CHARGING PUMP SUCTION TRANSFER TO THE RWST AND RCS DILUTION PATH ISOLATION

1. OPEN the following breakers (SFGD 790 Rm 1-070):

- ☐ • 1EB3-1/8C/BKR, RWST 1-01 TO CHARGING PUMP SUCTION VALVE 1-LCV-112D MOTOR BREAKER
- ☐ • 1EB3-1/5F/BKR, VCT CTRL 1-01 TO CHARGING PUMP SUCTION VLV 1-LCV-112B MOTOR BREAKER

2. OPEN the following breakers (AB 790 X-179):

- ☐ • 1EB4-1/8F/BKR, RWST 1-01 TO CHARGING PUMP SUCTION VLV 0112E MOTOR BREAKER
- ☐ • 1EB4-1/8C/BKR, VCT 1-01 TO CHARGING PUMP SUCTION VLV 0112C MOTOR BREAKER

3. Locally open the following valves (AB 810 Rm X-207):

- ☐ • 1-LCV-0112D, RWST 1-01 TO CHRG PMP SUCT VLV 0112D
- ☐ • 1-LCV-0112E, RWST 1-01 TO CHRG PMP SUCT VLV 0112E

[R] [C] 4. Locally close the following valves (AB 810 Rm X-203, Chrg Pmp Vlv Rm):

- ☐ • 1-LCV-0112B, VCT 1-01 TO CHRG PMP UPSTRM LVL CTRL VLV 0112B
- ☐ • 1-LCV-0112C, VCT 1-01 TO CHRG PMP DNSTRM LVL CTRL VLV 0112C

[C] 5. IF BOTH 1-ZL-8220 AND 1-ZL-8221 were NOT verified closed from Control Room, THEN close the following valves:

- ☐ • 1CS-0113, CCP 1-01 SUCT TO VCT VNT VLV (AB 810 Rm X-200 CCP 1-01)
- ☐ • 1CS-0114, CCP 1-02 SUCT VNT TO VCT VLV (AB 810 Rm X-201 CCP 1-02)
- ☐ • 1CS-0112, PD CHRG PMP 1-01 SUCT TO VCT VNT VLV (AB 810 Rm X-199 PDP 1-01)

ATTACHMENT 4
PAGE 2 OF 2

CHARGING PUMP SUCTION TRANSFER TO THE RWST
AND RCS DILUTION PATH ISOLATION

NOTE: These RCS dilution path isolation valves shall remain closed until control of Makeup System is regained.

6. Isolate Dilution Paths as follows:

☐ a. Close 1CS-8455, RMUW TO CVCS BA BLNDR 1-01 UPSTRM ISOL VLV (AB 822 Rm X-209 Blndr Rm)

OR

b. Perform the following:

☐ • Close 1CS-8560-RO, U1 CVCS CHRG PMP SUCT MU ISOL VLV RMT OPER (AB 822 Rm X-209 Blndr Rm)

[R] ☐ • Close 1-FCV-0111B (Fail Air), RCS MU TO VCT 1-01 ISOL VLV by closing 1-FCV-0111B-AS1, RCS MU TO VCT 1-01 ISOL VLV AS AND depressurizing regulator (SFGD 832 Rm 1-090 VCT Vlv Rm)

☐ • Close 1CS-8439-RO, U1 CVCS CHRG PMP EMER BORATE MAN VLV RMT OPER (AB 822 Rm X-209 Blndr Rm)

☐ • Close 1CS-8441, U1 RMUW TO EMER BORATE FLSH VLV (AB 822 Rm X-209 Blndr Rm)

☐ • Close 1CS-8453, CVCS CHEM MIX TK 1-01 IN VLV (AB 822 Rm X-209 Blndr Rm)

☐ 7. Notify the Reactor Operator that charging pump suction has been transferred to the RWST and RCS dilution paths have been isolated.

ATTACHMENT 5
PAGE 1 OF 2

6.9KV SAFEGUARD BUS LOADING SEQUENCE

CAUTION:
- When manually loading diesel generator, allow adequate time between major equipment starts for voltage to stabilize (~15 seconds).
- Do not exceed 700 AMPS on Diesel Generator. (This will limit load to less than 7.0 MW).

☐ 1. Verify proper bus voltage and frequency:

- V-1EA1-L 6600 - 7200 V
- F-1EA1-L 59.5 - 60.5 Hz
- V-1EA2-L 6600 - 7200 V
- F-1EA2-L 59.5 - 60.5 Hz

☐ 2. Start one Centrifugal Charging Pump:

- 1/1-APCH1L, CCP 1
- 1/1-APCH2L, CCP 2

[C] ☐ 3. IF SFP problems occur, THEN respond as necessary per ABN-909, ALM-0701, and TSC direction.

NOTE: Train A SSWP discharge valve should only close to a 10% open position

☐ 4. Close 1-HS-4286 FL, SSWP 1 DISCH VLV.

☐ 5. Start Station Service Water Pump(s):

- 1-HS-4250C, SSWP 1
- 1-HS-4251C, SSWP 2

ATTACHMENT 5
PAGE 2 OF 2

6.9KV SAFEGUARD BUS LOADING SEQUENCE

☐ 6. Open TRN A SSWP discharge valve AND verify flow on BOTH trains of Station Service Water:

- 1-HS-4286FL, SSWP 1 DISCH VLV
- 1-FI-4258B, SSWP 1 DISCH FLO
- 1-FI-4259B, SSWP 2 DISCH FLO

☐ 7. Start Component Cooling Water Pump(s):

- 1-HS-4518C, CCWP 1
- 1-HS-4519C, CCWP 2

[C] ☐ 8. Ensure CCW to SFP in service.

☐ 9. Start 1-HS-6700FL, SFTY CH WTR RECIRC PMP 5.

☐ 10. Start Motor Driven Auxiliary Feedwater Pump(s):

- 1-HS-2450C, MD AFWP 1
- 1-HS-2451C, MD AFWP 2

☐ 11. IF Emergency Fan Cooler Units have been transferred to local control, THEN dispatch an Operator to restart them locally per Attachment 8.

☐ 12. IF RHR Train A had been in recirculation cooling, THEN restart 1/1-APRH1F, RHRP 1 per Shift Manager direction.

ATTACHMENT 6
PAGE 1 OF 1

SI BLOCK FROM THE CABLE SPREAD ROOM

NOTE: The following steps may be performed in any order.

☐ 1. [CV] At termination cabinet 1-TC-10, momentarily (approximately 2-10 seconds) jumper terminals TB3-13 and TB3-14. This action blocks Train A low pressurizer pressure safety injection. |

TB3-13 E0127557(W) TB3-14 E0127557(B) ______

Verified By:______

☐ 2. [CV] At termination cabinet 1-TC-14, momentarily (approximately 2-10 seconds) jumper terminals TB2-82 and TB2-83. This action blocks Train B low pressurizer pressure safety injection. |

TB2-82 EG127658(W) TB2-83 EG127658(B) ______

Verified By:______

☐ 3. [CV] At termination cabinet 1-TC-16, momentarily (approximately 2-10 seconds) jumper terminals TB2-10 and TB2-11. This action blocks Train A low steam line pressure safety injection. |

TB2-10 E0127556(W) TB2-11 E0127556(B) ______

Verified By:______

☐ 4. [CV] At termination cabinet 1-TC-17, momentarily (approximately 2-10 seconds) jumper terminals TB2-31 and TB2-32. This action blocks Train B low steam line pressure safety injection. |

TB2-31 EG127653(W) TB2-32 EG127653(B) ______

Verified By:______

☐ 5. Complete I&C signature record:

- Performed by: ______________ / ______________________ / ____________
  INITIALS PRINT NAME DATE
- Verified by: ______________ / ______________________ / ____________
  INITIALS PRINT NAME DATE

☐ 6. When completed, this attachment shall be dispositioned by attaching it to the Condition Report generated as result of this abnormal condition. |

ATTACHMENT 7
PAGE 1 OF 2

RCS PRESSURE/TEMPERATURE VERIFICATION

Time								
PRZR PRESS	1-PI-455B							
Tsat from Steam Table (2)								
PRZR LVL	1-LI-459B							
NEUT FLUX SR	1-NI-50A-3							
RCS LOOP (4)	CL1							
1 & 2 TEMP	CL2							
1-TR-410F	HL1							
	HL2							
Calculated Subcooling ˚F								
SG 1 PRESS (2)	1-PI-514B							
Tsat from Steam Table (2)								
SG 1 LVL (WR) (1)	1-LI-501A							
SG 2 LVL (WR) (1)	1-LI-502A							
SG 2 PRESS (2)	1-PI-524B							
Tsat from Steam Table (2)								
RCS LOOP (4)	CL3							
3 & 4 TEMP	CL4							
1-TR-430F	HL3							
	HL4							
SG 3 PRESS (2)	1-PI-534B							
Tsat from Steam Table (2)								
SG 3 LVL (WR) (1)	1-LI-503A							
SG 4 LVL (WR) (1)	1-LI-504A							
SG 4 PRESS (2)	1-PI-544B							
Tsat from ST								
COOLDOWN RATE	(3)							

(1) SG Level (WR) Cold Cal of approximately 74% corresponds to an AFW Pump Low Level Auto Start signal.

(2) Steam pressure converted to Tsat/Tcold is the best indication of temperature and temperature changes.

(3) Cooldown rate should be calculated based on most conservative SG Press reading. Calculate cooldown using Tsat values and steam tables, with SG Press reading that has dropped the largest amount from last reading.

(4) RCS indicated temperature response will be slow due to slow response time of strap on RTDs.

NOTE: When completed, this attachment shall be dispositioned by attaching it to the SMART Form generated as a result of this abnormal condition.

ATTACHMENT 7
PAGE 2 OF 2

RCS PRESSURE/TEMPERATURE VERIFICATION

Time								
PRZR PRESS	1-PI-455B							
Tsat from Steam Table (2)								
PRZR LVL	1-LI-459B							
NEUT FLUX SR	1-NI-50A-3							
RCS LOOP (4)	CL1							
1 & 2 TEMP	CL2							
1-TR-410F	HL1							
	HL2							
Calculated Subcooling ˚F								
SG 1 PRESS (2)	1-PI-514B							
Tsat from Steam Table (2)								
SG 1 LVL (WR) (1)	1-LI-501A							
SG 2 LVL (WR) (1)	1-LI-502A							
SG 2 PRESS (2)	1-PI-524B							
Tsat from Steam Table (2)								
RCS LOOP (4)	CL3							
3 & 4 TEMP	CL4							
1-TR-430F	HL3							
	HL4							
SG 3 PRESS (2)	1-PI-534B							
Tsat from Steam Table (2)								
SG 3 LVL (WR) (1)	1-LI-503A							
SG 4 LVL (WR) (1)	1-LI-504A							
SG 4 PRESS (2)	1-PI-544B							
Tsat from ST								
COOLDOWN RATE	(3)							

(1) SG Level (WR) Cold Cal of approximately 74% corresponds to an AFW Pump Low Level Auto Start signal.

(2) Steam pressure converted to Tsat/Tcold is the best indication of temperature and temperature changes.

(3) Cooldown rate should be calculated based on most conservative SG Press reading. Calculate cooldown using Tsat values and steam tables, with SG Press reading that has dropped the largest amount from last reading.

(4) RCS indicated temperature response will be slow due to slow response time of strap on RTDs.

NOTE: When completed, this attachment shall be dispositioned by attaching it to the SMART Form generated as a result of this abnormal condition.

ATTACHMENT 8
PAGE 1 OF 2

EMERGENCY FAN COOLER UNITS

> CAUTION: Loss of power to the 6.9 KV Safeguards buses after the emergency fan cooler units have been transferred to local control, causes the emergency fan cooler units to remain stopped until locally restarted.

1. Transfer control of Emergency fan cooler units and start the fans for the following equipment:

	EQUIPMENT	SWITCH	POSITION
☐	• RHRP 2 (SFGD 773 Rm 1-052 Inside Pump Room)	1-HS-5670B 1-HS-5670C	LOCAL START
☐	• RHRP 1 (SFGD 790 Rm 1-071 Hall Across From AFWP)	1-HS-5668B 1-HS-5668C	LOCAL START
☐	• MDAFWP 1 (SFGD 790 Rm 1-071 Outside Pump Room)	1-HS-5676B 1-HS-5676C	LOCAL START
☐	• MDAFWP 2 (SFGD 790 Rm 1-071 Outside Pump Room)	1-HS-5678B 1-HS-5678C	LOCAL START
☐	• CCP 1 (SFGD 790 Rm 1-071 Hall Near AFWP)	1-HS-5802-B 1-HS-5802-C	LOCAL START
☐	• TRN A ELEC AREA (SFGD 810 Rm 1-083 Outside Of HVAC Room)	1-HS-5684-A2 1-HS-5684-A3 1-HS-5684-B2 1-HS-5684-B3	LOCAL START LOCAL START

ATTACHMENT 8
PAGE 2 OF 2

EMERGENCY FAN COOLER UNITS

	EQUIPMENT	SWITCH	POSITION
☐	• CCWP 1 (AB 810 Rm X-205 Inside Pump Room)	1-HS-5800-B 1-HS-5800-C	LOCAL START
☐	• CCWP 2 (AB 810 Rm X-198 Outside Pump Room)	1-HS-5801-B 1-HS-5801-C	LOCAL START
☐	• CCP 2 (AB 810 Rm X-201 Outside Pump Room)	1-HS-5803-B 1-HS-5803-C	LOCAL START
☐	• SFP PMP 1 (FB 810 Rm X-249B Outside Pump Room)	X-HS-5805-B X-HS-5805-C	LOCAL START
☐	• SFP PMP 2 (FB 810 Rm X-249B Outside Pump Room)	X-HS-5806-B X-HS-5806-C	LOCAL START
☐	• TRN B ELEC AREA (SFGD 852 Rm 1-104 Outside Of HVAC Room)	1-HS-5686-A2 1-HS-5686-A3 1-HS-5686-B2 1-HS-5686-B3	LOCAL START LOCAL START

ATTACHMENT 9
PAGE 1 OF 1

CONTROL TRANSFER OF STEAM GENERATOR ATMOSPHERIC RELIEF VALVES

NOTE: Tools needed to open the following junction boxes are located in the Safe Shutdown Repair Kit (located in the SFGD 790 N-S Hallway across from Chem Add Tank Area).

1. Obtain RSP manual control of SG Atmos Rlf valves as follows:

   a. Open appropriate junction boxes:

	CONNECTOR	SWITCHES	LOCATION
☐	• JB1S-1277	JB1S-1053O	SFGD 873, SG ATMOS ACCUM RM, South wall off stairway to 880.
☐	• JB1S-1276	JB1S-1051G	SFGD 852, SG High Pressure Chemical Feed Area

☐ ☐ b. Place disconnect switches in OFF.

☐ ☐ c. Route cable through conduit from junction box listed under CONNECTOR to junction box listed under SWITCHES.

☐ ☐ d. Connect prefabricated connector.

☐ ☐ e. Close junction boxes.

ATTACHMENT 10
PAGE 1 OF 1

CONTROLTRANSFER OF RC LOOP 4 PRZR SPR VLV (1-PCV-0455C), 1-HCV-0606, AND 1-FCV-0618

> NOTE: JB1S-942 is thermolagged. The thermolag must be removed to obtain access to this junction box. Tools are located at the Remote Shutdown Panel and in the Fire Safe Shutdown Repair Kit (SFGD 790 N-S Hallway across from Chem Add Tank Area).

1. Obtain RSP control of valves as follows:

☐ a. Open junction box:

JUNCTION BOX	LOCATION
JB1S-942	SFGD 832 West side of column North of the RSP

☐ b. Place ALL disconnect switches in OFF.

☐ c. Connect prefabricated connector.

☐ d. Close junction box.

ATTACHMENT 11
PAGE 1 OF 3

LOCAL START OF DIESEL GENERATORS

1. Start Train A Diesel Generator as follows:

NOTE: With 1-HS-3413-3B, RLMS (MASTER SWITCH) in LOCAL or 43/1EG1, DG 1 BKR 1EG1 CTRL XFER switch in HSP, the Diesel Generator Auto Starts are defeated. |

☐ a. Place 1-HS-3413-3B, RLMS (MASTER SWITCH) (DG local generator control panel) in LOCAL.

CAUTION: Do NOT run the Aux Lube oil pump in HAND for more than one (1) minute. This is to prevent flooding the turbo chargers with oil.

☐ b. Place 1-HS-3411-1, AUXILIARY LUBE OIL PUMP handswitch in HAND (DG local engine control panel) AND allow Lube Oil pressure to stabilize (40 - 65 psig). |

☐ c. Stop the Auxiliary Lube Oil Pump and place the handswitch in AUTO.

☐ d. Within 60 seconds of stopping the Auxiliary Lube Oil Pump, Momentarily turn 1-HS-3413-2B, LOCAL NORMAL STOP-START switch (DG local generator control panel) to START. |

☐ e. Ensure 1-HS-3415-1, AUXILIARY JACKET WATER PUMP handswitch (DG local engine control panel) in AUTO. |

☐ f. Check the following operating parameters within limits:

- FREQUENCY, 59.5 - 60.5 Hz
- VOLTAGE, 6600 - 7200 volts
- 1-PI-3411-1B, LUBE OIL HEADER PRESS, 40-65 psig
- 1-PI-3411-3A, LEFT TURBO OIL PRESS, 20-40 psig
- 1-PI-3411-3B, RIGHT TURBO OIL PRESS, 20-40 psig
- 1-PI-3409-3, FUEL OIL PRESS, 20-60 psig
- 1-PI-3415-1, JACKET WATER PRESS, 10-30 psig
- 1-SI-3413-B3, ENG SPEED, 440-460 rpm

☐ g. Notify RO that TRN A Diesel Generator is running and may be loaded as necessary.

ATTACHMENT 11
PAGE 2 OF 3

LOCAL START OF DIESEL GENERATORS

2. Start Train B Diesel Generator as follows:

NOTE: With 1-HS-3414-3B, RLMS (MASTER SWITCH) in LOCAL or 43-1EG2, DG 2 BKR 1EG2 CTRL XFER, switch in the HSP position, the Diesel Generator Auto Starts are defeated. |

☐ a. Place 1-HS-3414-3B, MASTER SWITCH (DG local generator control panel) in LOCAL.

CAUTION: Do NOT run the Aux Lube oil pump in HAND for more than one (1) minute. This is to prevent flooding the turbo chargers with oil.

☐ b. Place 1-HS-3412-1, AUXILIARY LUBE OIL PUMP handswitch in HAND (DG local engine control panel) and allow Turbo Lube Oil pressure to stabilize (40 - 65 psig). |

☐ c. Stop the Auxiliary Lube Oil Pump and place the handswitch in AUTO.

☐ d. Within 60 seconds of stopping the Auxiliary Lube Oil Pump, Momentarily turn 1-HS-3414-2B, LOCAL NORMAL STOP-START switch (DG local generator control panel) to START. |

☐ e. Ensure 1-HS-3416-1, AUXILIARY JACKET WATER PUMP handswitch (DG local engine control panel) in AUTO. |

☐ f. Check the following operating parameters within limits:

- VOLTAGE, 6600 - 7200 volts
- FREQUENCY, 59.5 - 60.5 Hz
- 1-PI-3412-1B, LUBE OIL HEADER PRESS, 40-65 psig
- 1-PI-3412-3A, LEFT TURBO OIL PRESS, 20-40 psig
- 1-PI-3412-3B, RIGHT TURBO OIL PRESS, 20-40 psig
- 1-PI-3416-1, JACK WATER PRESS, 10-30 psig
- 1-PI-3410-3, FUEL OIL PRESS, 20-60 psig
- 1-SI-3414-B3, ENG SPEED, 440-460 rpm

☐ g. Notify RO that TRN B Diesel Generator is running and may be loaded as necessary.

ATTACHMENT 11
PAGE 3 OF 3

LOCAL START OF DIESEL GENERATORS

3. IF a local emergency manual start was initiated AND it is desired to re-instate full shutdown protection, THEN place LOCAL EMERG STOP OFF START switch in OFF (center) position (selected DG's local generator control panel) and verify SHUTDOWN SYSTEM ACTIVE light is lit (local engine control panel). |

DG 1

☐ • 1-HS-3413-4B, LOCAL EMERG STOP OFF START - OFF |

☐ • SHUTDOWN SYSTEM ACTIVE light - LIT

DG 2

☐ • 1-HS-3414-4B, LOCAL EMERG STOP OFF START - OFF |

☐ • SHUTDOWN SYSTEM ACTIVE light - LIT

ATTACHMENT 12
PAGE 1 OF 1

BORATION

NOTE: Pressurizer heaters and spray may be used to enhance boric acid addition to the pressurizer when borating to CSD conditions.

☐ 1. Transfer the following from CR to HSP:

- 43/1 - APBA1L, BA XFER PMP 1 CTRL XFER (STP)
- 43/1 - APBA2L, BA XFER PMP 2 CTRL XFER (RSP)
- 43/1 - 8104L, EMER BORATE VLV CTRL XFER (RSP)

☐ 2. Start one Boric Acid Transfer Pump:

- 1/1 - APBA1L, BA XFER PMP 1 (RSP)
- 1/1 - APBA2L, BA XFER PMP 2 (RSP)

☐ 3. Open 1/1-8104L, EMER BORATE VLV (RSP).

☐ 4. Monitor 1-FI-183B, EMER BORATE FLO (RSP).

5. WHEN the desired amount of Boric Acid has been added, THEN stop boration:

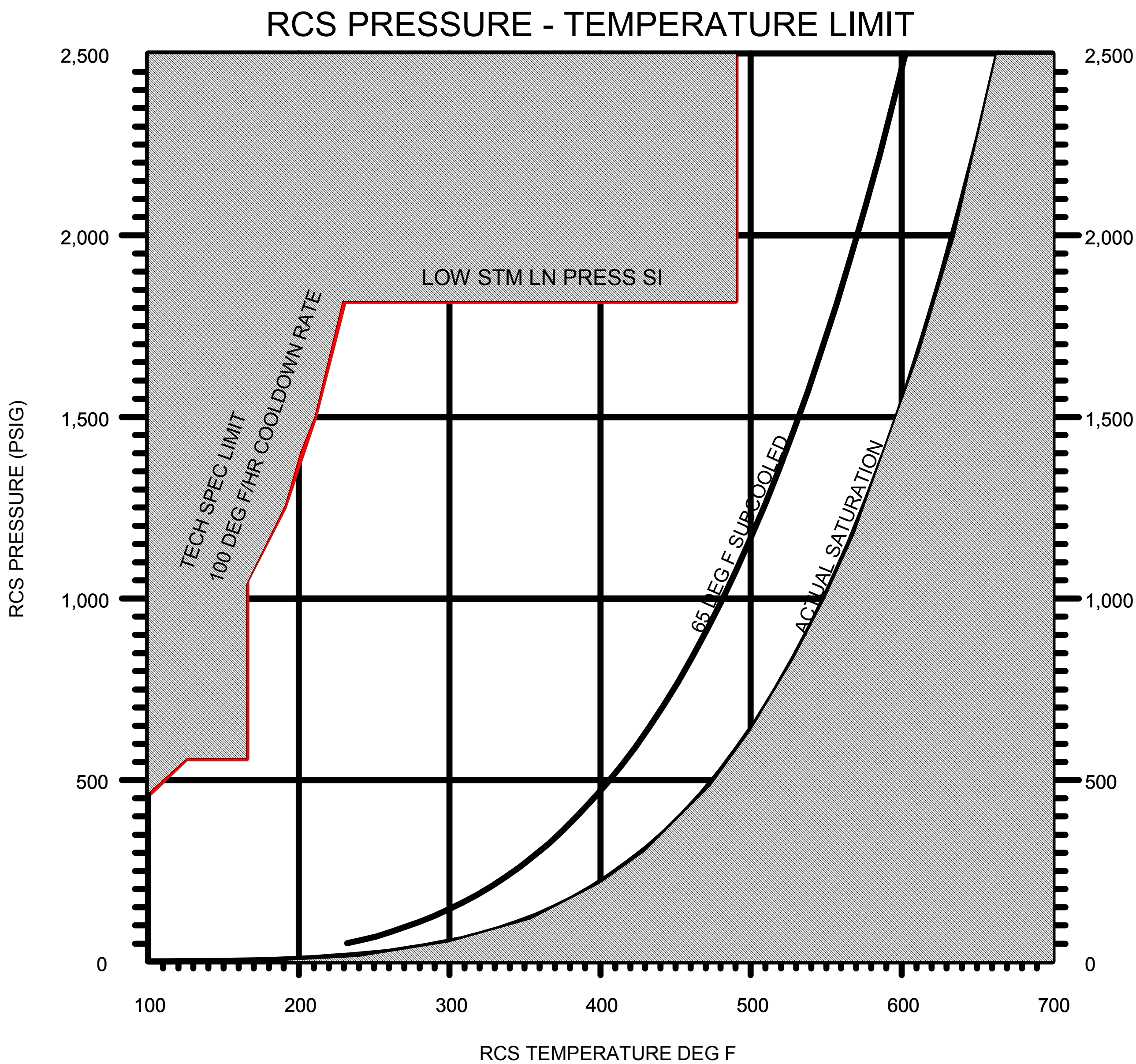
☐ a. Close 1/1-8104L, EMER BORATE VLV (RSP).

☐ b. Stop the Boric Acid Transfer Pump:

- 1/1-APBA1L, BA XFER PMP 1 (RSP)
- 1/1-APBA2L, BA XFER PMP 2 (RSP)

ATTACHMENT 13
PAGE 1 OF 1

RCS PRESSURE - TEMPERATURE LIMIT



ATTACHMENT 14
PAGE 1 OF 1

CONTROL TRANSFER OF 1-8702A

CAUTION: 480 VAC present. ENSURE breakers OPEN prior to disconnecting cables.

1. Open the following breakers:

☐ • 1EB4-2/8G/BKR-1, RHRP 1-01 HL 1-01 RECIRC IMB ISOL VLV 1-8702A PREF MOT BKR 1 (SFGD 852 Rm 1-103)

☐ • 1EB4-2/8G/BKR-2, RHR PUMP 1-01 HOT LEG 1-01 RECIRC IMB ISOL VLV 1-8702A PREF MOT BKR 2 (SFGD 852 Rm 1-103)

☐ • 1EB3-2/8RF/BKR-1, RHRP 1-01 HL 1-01 RECIRC IMB ISOL VLV 1-8702A ALT MOT BKR 1 (SFGD 810 Rm 1-083)

☐ • 1EB3-2/8RF/BKR-2, RHR PMP 1-01 HL 1-01 RECIRC IMB ISOL VALVE 1-8702A ALT MOT BREAKER 2 (SFGD 810 Rm 1-083)

2. Disconnect the following control cables from their connectors in JB1S-1006G (SFGD 852 Rm 1-103 on the outer containment wall).

☐ • Cable EG122929A from connector C-1-8702A-CN

☐ • Cable EG100847A from connector C-1-8702A-PN

NOTE: Two people handling the cables through JB1S-1007G may be required to accomplish this task in a timely manner.

☐ 3. Route disconnected cables to JB1S-1005O via JB1S-1007G.

4. Plug routed cables into their respective connectors at JB1S-1005O:

☐ • EG122929A into connector C-1-8702A-CA

☐ • EG100847A into connector C-1-8702A-PA

5. Close the following breakers:

☐ • 1EB3-2/8RF/BKR-1, RHRP 1-01 HL 1-01 RECIRC IMB ISOL VLV 1-8702A ALT MOT BKR 1 (SFGD 810 Rm 1-083)

☐ • 1EB3-2/8RF/BKR-2, RHR PMP 1-01 HL 1-01 RECIRC IMB ISOL VALVE 1-8702A ALT MOT BREAKER 2 (SFGD 810 Rm 1-083)

ATTACHMENT 15
PAGE 1 OF 1

LOCAL CONTROL OF 1-HCV-0128, RHR LTDN FLO CTRL

☐ 1. Contact I&C Department to perform steps below.

☐ [R] 2. At SFGD 810 LTDN Hx Vlv Rm, remove the I/P cover for 1-HCY-0128 and disconnect the positive (+) field lead from the I/P terminal boards.

Verified By: ______ ______

☐ 3. Connect the current source (Transmation 4-20 MA) with a DMM in series to the I/P plus (+) and minus (-) terminals.

Verified By: ______ ______

☐ 4. Notify the Reactor Operator at the Remote Shutdown Panel when above steps are completed.

☐ 5. Complete I&C signature record for above steps.

- Performed by: ______ / ______ / ______
  INITIALS PRINT NAME DATE
- Verified by: ______ / ______ / ______
  INITIALS PRINT NAME DATE

☐ [R] 6. WHEN requested to restore 1-HCY-0128, THEN disconnect the current source and DMM and reland the positive + field lead to the I/P terminal boards.

Verified By: ______ ______

☐ 7. Reinstall the I/P cover on 1-HCY-0128.

☐ 8. Notify the Reactor Operator at the Remote Shutdown Panel when above steps are complete.

☐ 9. Complete I&C signature record.

- Performed by: ______ / ______ / ______
  INITIALS PRINT NAME DATE
- Verified by: ______ / ______ / ______
  INITIALS PRINT NAME DATE

☐ 10. When completed, this attachment shall be dispositioned by attaching it to the SMART form generated as result of this abnormal condition.

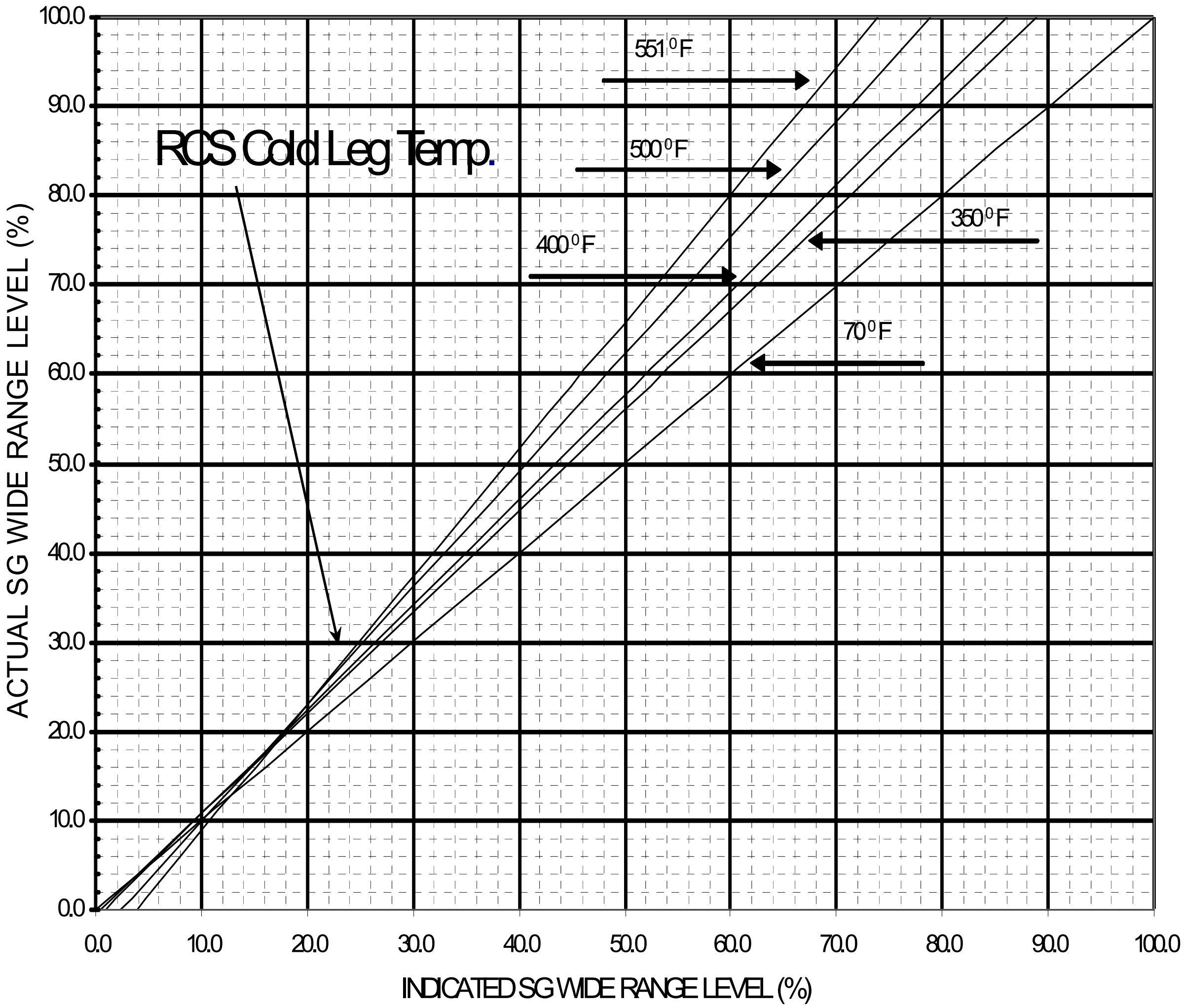
ATTACHMENT 16
PAGE 1 OF 1

SG LEVEL TEMPERATURE CORRECTION

NOTE: Normal SG level for Hot Standby and Cooldown (60 - 75% NR) is between 83% and 90% actual wide range. Operating outside this range could cause uncovering AFW nozzle OR ESF actuation OR moisture carryover. Approximate critical levels (actual wide range) are:

- Lo-Lo (ESF actuation) Unit 1 - 74%
- AFW Nozzle Unit 1 - 83%
- Hi-Hi (moisture carryover) 92%

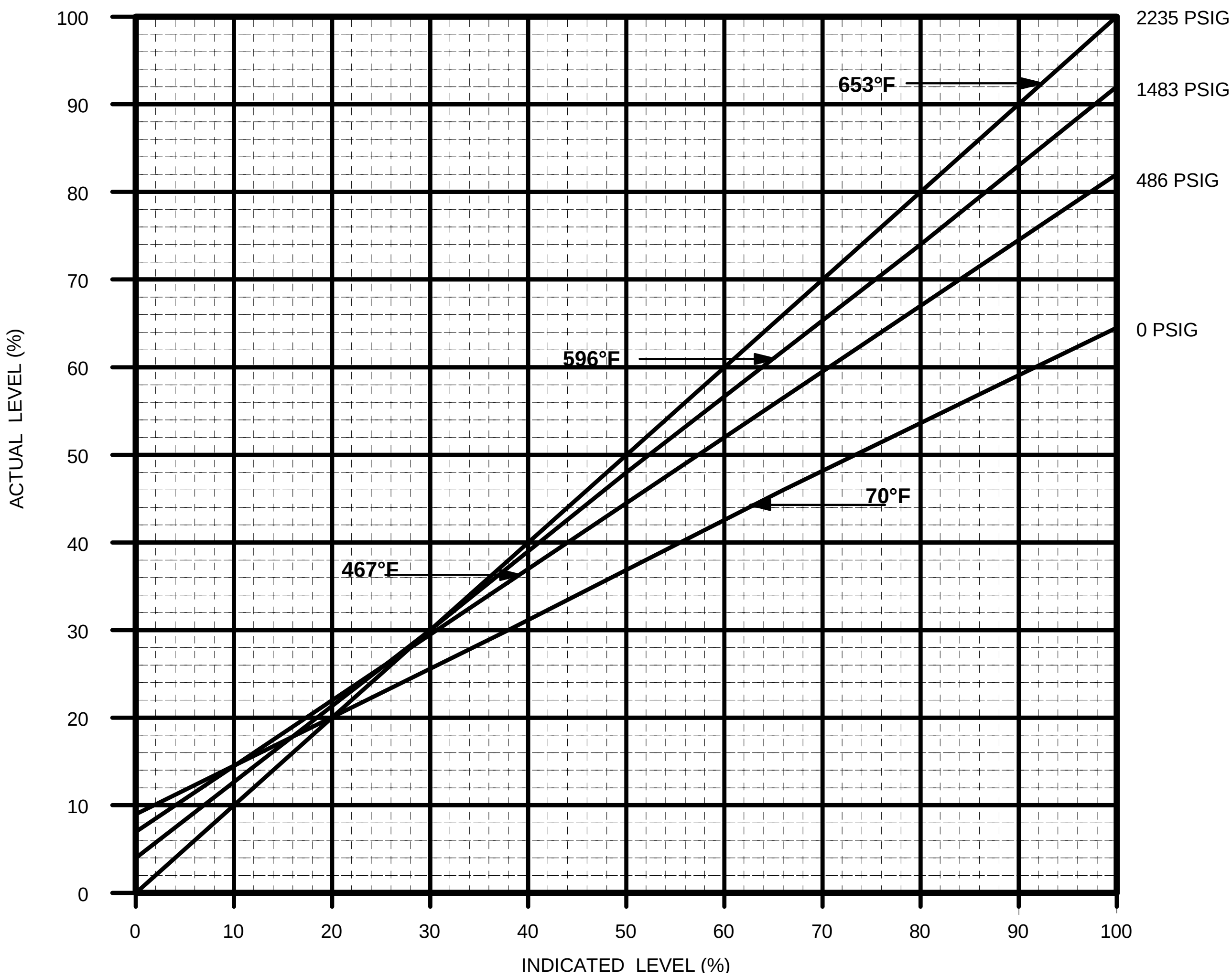
(L)



ATTACHMENT 17
PAGE 1 OF 1

PRZR LEVEL TEMPERATURE CORRECTION

PRESSURIZER LEVEL CHANNEL
(Hot Calibrated)
(LI-459B, LI-460B)



ATTACHMENT 18
PAGE 1 OF 6

TRANSFER OF CONTROL TO THE MAIN CONTROL ROOM

NOTE:	Management review of steps previously performed is necessary to ensure configuration tracking and restoration.

☐ 1. As a minimum, one Shift Manager or Unit Supervisor and two Reactor Operators should be thoroughly briefed on the plant status and assigned to the Main Control Room. One Shift Manager or Unit Supervisor and one Reactor Operator shall remain at the RSP. One Reactor Operator shall be assigned to the STP.

☐ 2. Establish communication between the Control Room, RSP and STP.

☐ 3. RCS dilution isolation valves shall remain closed until control of the CVCS and Reactor Makeup System is regained.

☐ 4. IF Trn A RHR is in recirculation cooling, THEN start up Trn B RHR from the control room AND shut down Trn A RHR from the RSP prior to transferring control of Trn A RHR system to the Control Room.

☐ 5. After extended unloaded operation of the Diesel Generators, they should be loaded to at least 3500 KW for 60 minutes to remove any unburned fuel oil in the exhaust system.

☐ 6. Controls should be transferred on a system by system basis, as requested by the Control Room staff.

☐ 7. WHEN transferring control handswitches from RSP to Control Room, THEN ensure Control Room handswitch is in the present condition of the component (e.g. If SSW Pump running, handswitch should be in Auto after start).

TRANSFER OF CONTROL TO THE MAIN CONTROL ROOM

NOTE: Most Train B controllers track Remote Shutdown demand to provide a bumpless transfer back to the control room.

8. The following guidelines should be used during controller transfer to the Control Room:

   a. IF the controller can be taken to minimum (e.g. AFW flow controller taken to 0% and flow to SG momentarily isolated), THEN perform the following:

      ☐ 1) Ensure the controller(s) at the RSP and Control Room are in manual and 0% demand.

      ☐ 2) Transfer control from RSP to Control Room.

      ☐ 3) Adjust controller from Control Room as necessary to obtain desired output.

CAUTION: Do NOT attempt to adjust the DEMAND pushbuttons on the Control Room charging flow controller until after the transfer from the RSP is complete. Although Control Room flow controller tracks the RSP flow controller position, MCB flow indication is disabled.

   b. IF the controller needs to maintain a specific condition (e.g. Charging flow control valve), THEN perform the following:

      ☐ 1) Reduce controller output at RSP to a value based on system conditions.

      ☐ 2) While closely monitoring the parameter maintained by the controller, transfer control from RSP to control room.

      ☐ 3) Adjust controller from Control Room as necessary to obtain desired output.

ATTACHMENT 18
PAGE 3 OF 6

TRANSFER OF CONTROL TO THE MAIN CONTROL ROOM

9. While transferring components from RSP to CR control, the status of each transfer switch may be tracked by marking up Attachments 1 and 2.

   a. WHEN transferring control of deenergized equipment, THEN ensure the control board switch is in the position corresponding to actual equipment condition prior to reenergizing.

> NOTE: The following is a list of equipment which may have been deenergized during performance of this procedure.

- ☐ • 1-LCV-0112D, RWST 1-01 TO CHRG PMP SUCT VLV 0112D, 1EB3-1/8C/BKR (valve open with breaker open)
- ☐ • 1-LCV-0112B, VCT 1-01 TO CHRG PMP UPSTRM LVL CTRL VLV 0112B, 1EB3-1/5F/BKR (valve closed with breaker open)
- ☐ • 1-LCV-0112E, RWST 1-01 TO CHRG PMP SUCT VLV 0112E, 1EB4-1/8F/BKR (valve open with breaker open)
- ☐ • 1-LCV-0112C, VCT 1-01 TO CHRG PMP DNSTRM LVL CTRL VLV 0112C, 1EB4-1/8C/BKR (valve closed with breaker open)
- ☐ • PRZR CTRL HTR GROUP C, 1EB1/6D/BKR (off and control power fuses removed)
- ☐ • PRZR BACKUP HTR GROUP D, 1EB4/11B/BKR (off and control power fuses removed)
- ☐ • POSITIVE DISPLACEMENT PUMP 1-01 MOTOR BREAKER, 1EB1/2B/BKR (off and control power fuses removed)
- ☐ • 1-HV-4572, RHR HX 1-01 CCW RET VLV, 1EB3-1/7C/BKR (valve open with breaker open)
- ☐ • 1-FCV-0610, RHRP 1-01 MINIFLO VLV, 1EB1/1J/DSW (valve closed with breaker open)
- ☐ • 1-8812A, RWST 1-01 TO RHR PMP 1-01 SUCT VLV, 1EB3-1/1G/BKR (valve closed with breaker open)

“Step continued next page”

ATTACHMENT 18
PAGE 4 OF 6

TRANSFER OF CONTROL TO THE MAIN CONTROL ROOM

NOTE: If RHR is cooling RCS, Train B should be operating and Train A should be shut down prior to transfer.

9 ☐ b. Ensure Train B RHR aligned for service AND Train A RHR shut down.

☐ c. Transfer 43/1-APRH1F RHRP 1 CTRL XFER (STP) from HSP to CR.

d. Normal control of SG ATMOS RLF valves, RC LOOP 4 PRZR SPR VLV, 1-HCV-0606 and 1-FCV-0618 may be obtained in the following manner:

☐ 1) Place the RSP controllers in manual and closed (EXCEPT 1-HC-606A, RHR HX 1 FLO CTRL should be OPEN).

☐ 2) Open the appropriate junction box in Attachment 9 OR Attachment 10.

☐ 3) Disconnect the prefabricated connector.

☐ 4) Place disconnect switches in ON.

☐ 5) Close AND secure junction box door.

e. Ensure control of ATMOS RLF valves has been transferred to CR from RSP:

☐ • 1-PK-2325, SG 1 ATMOS RLF CTRL

☐ • 1-PK-2326, SG 2 ATMOS RLF CTRL

☐ • 1-PK-2327, SG 3 ATMOS RLF CTRL

☐ • 1-PK-2328, SG 4 ATMOS RLF CTRL

f. Transfer MSIV control to CR.

☐ • 1-HS-2333FT, MSIV 1 CTRL XFER (STP)

☐ • 1-HS-2334FT, MSIV 2 CTRL XFER (STP)

☐ • 1-HS-2335FT, MSIV 3 CTRL XFER (STP)

☐ • 1-HS-2336FT, MSIV 4 CTRL XFER (STP)

"Step continued next page"

ATTACHMENT 18
PAGE 5 OF 6

TRANSFER OF CONTROL TO THE MAIN CONTROL ROOM

NOTE:	If letdown was placed in service, letdown is being controlled locally. 1-HCV-0128, LTDN FLO CTRL is opened locally and 1-PCV-0131 is isolated.

g. Letdown should be transferred as follows:

☐ 1) Isolate letdown by closing 1CS-8409-RO, U1 LTDN HX OUT PRESS CTRL VLV BYP VLV RMT OPER.

☐ 2) Close 1RH-8734A, RHR HX 1-01 TO CVCS LTDN ISOL VLV RMT OPER.

☐ 3) Contact I&C and request removal of Transmation (4-20 MA) supply to 1-HCY-0128 (SFGD 810 Ltdn Hx Rm) per Attachment 15.

☐ 4) Verify I&C test equipment has been removed from 1-HCY-0128 (SFGD 810 Ltdn Hx Rm).

☐ 5) Ensure 1-8408A, U1 LTDN PRESS CTRL UPSTRM ISOL VLV (SFGD 810 Ltdn HX Vlv Rm 1-080) - OPEN

☐ 6) Ensure 1-8408B, U1 LTDN PRESS CTRL DNSTRM ISOL VLV (SFGD 810 U1 Ltdn HX Vlv Rm 1-080) - OPEN

☐ 7) Align letdown, as desired, in accordance with normal System Operating Procedures.

ATTACHMENT 18
PAGE 6 OF 6

TRANSFER OF CONTROL TO THE MAIN CONTROL ROOM

10. Transfer of 1-8702A control should be performed as follows:

a. Open the following breakers:

- ☐ • 1EB4-2/8G/BKR-1, RHRP 1-01 HL 1-01 RECIRC IMB ISOL VLV 1-8702A PREF MOT BKR 1 (SFGD 852 Rm 1-103)
- ☐ • 1EB4-2/8G/BKR-2, RHR PUMP 1-01 HOT LEG 1-01 RECIRC IMB ISOL VLV 1-8702A PREF MOT BKR 2 (SFGD 852 Rm 1-103)
- ☐ • 1EB3-2/8RF/BKR-1, RHRP 1-01 HL 1-01 RECIRC IMB ISOL VLV 1-8702A ALT MOT BKR 1 (SFGD 810 Rm 1-083)
- ☐ • 1EB3-2/8RF/BKR-2, RHR PMP 1-01 HL 1-01 RECIRC IMB ISOL VALVE 1-8702A ALT MOT BREAKER 2 (SFGD 810 Rm 1-083)

b. Disconnect the following control cables from their connectors in JB1S-1005O (SFGD 852 Rm 1-103 on the outer containment wall)

- ☐ • EG122929A from connector C-1-8702A-CA
- ☐ • EG100847A from connector C-1-8702A-PA

☐ c. Route disconnected cables to JB1S-1006G via JB1S-1007O.

d. Plug routed cables into their respective connectors at JB1S-1006G.

- ☐ • EG122929A into connector C-1-8702A-CN
- ☐ • EG100847A into connector C-1-8702A-PN

e. Open the following breakers:

- ☐ • 1EB4-2/8G/BKR-1, RHRP 1-01 HL 1-01 RECIRC IMB ISOL VLV 1-8702A PREF MOT BKR 1 (SFGD 852 Rm 1-103)
- ☐ • 1EB4-2/8G/BKR-2, RHR PUMP 1-01 HOT LEG 1-01 RECIRC IMB ISOL VLV 1-8702A PREF MOT BKR 2 (SFGD 852 Rm 1-103)

☐ f. Initiate a Work Request per STA-606, to reinstall thermolag on JB1S-942.

☐ 11. Perform OPT-108.

☐ 12. Perform a management review of all systems/components operated in this procedure to ensure system configuration tracking and restoration.

ATTACHMENT 19
PAGE 1 OF 4

CLOSING ACCUMULATOR ISOLATION VALVES FROM THE MCC

NOTE: Refer to the following drawings for this attachment:
2323-E1-0062 Sheet 16-19

1. Close 1-8808A, SI ACCUM 1-01 INJ VLV from 1EB3-2/6F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 1 (SFGD 810 Rm 1-083) as follows:

   a. Open the following breakers:

   ☐ • 1EB3-2/6F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 1

   ☐ • 1EB3-2/6F/BKR-2, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 2

[CV] ☐ b. Within 1EB3-2/6F/BKR-1, place a jumper between the following two terminations: |

   • Termination X2
   • Termination 7 ______

   Verified By: ______

   c. Leaving door open, ensure the following breakers CLOSED.

   ☐ • 1EB3-2/6F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 1

   ☐ • 1EB3-2/6F/BKR-2, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 2

☐ d. Momentarily depress the close contactor (42c).

   e. WHEN the close contactor opens, THEN OPEN the following breakers:

   ☐ • 1EB3-2/6F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 1

   ☐ • 1EB3-2/6F/BKR-2, SAFETY INJECTION ACCUMULATOR 1-01 INJ VLV 1-8808A MOTOR BREAKER 2

[CV] ☐ f. Remove jumper placed in step b above (within 1EB3-2/6F/BKR-1): |

   • Termination X2
   • Termination 7 ______

   Verified By: ______

ATTACHMENT 19
PAGE 2 OF 4

CLOSING ACCUMULATOR ISOLATION VALVES FROM THE MCC

2. Close 1-8808C, SI ACCUM 1-03 INJ VLV from 1EB3-2/6M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 1 (SFGD 810 Rm 1-083) as follows:

a. Open the following breakers:

☐ • 1EB3-2/6M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 1

☐ • 1EB3-2/6M/BKR-2, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 2

[CV] ☐ b. Within 1EB3-2/6M/BKR-1, place a jumper between the following two terminations: |

- Termination X2
- Termination 7 ______

Verified By: ______

c. Leaving door open, ensure the following breakers CLOSED.

☐ • 1EB3-2/6M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 1

☐ • 1EB3-2/6M/BKR-2, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 2

☐ d. Momentarily depress the close contactor (42c).

e. WHEN the close contactor opens, THEN OPEN the following breakers:

☐ • 1EB3-2/6M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 1

☐ • 1EB3-2/6M/BKR-2, SAFETY INJECTION ACCUMULATOR 1-03 INJ VLV 1-8808C MOTOR BREAKER 2

[CV] ☐ f) Remove jumper placed in step b above (within 1EB3-2/6M/BKR-1): |

- Termination X2
- Termination 7 ______

Verified By: ______

ATTACHMENT 19
PAGE 3 OF 4

CLOSING ACCUMULATOR ISOLATION VALVES FROM THE MCC

3. Close 1-8808B, SI ACCUM 1-02 INJ VLV from 1EB4-2/5F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 1 (SFGD 852 Rm 1-103) as follows:

a. Open the following breakers:

☐ • 1EB4-2/5F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 1

☐ • 1EB4-2/5F/BKR-2, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 2

[CV] ☐ b. Within 1EB4-2/5F/BKR-1, place a jumper between the following two terminations:

- Termination X2
- Termination 7 ______

Verified By: ______

c. Leaving door open, ensure the following breakers CLOSED.

☐ • 1EB4-2/5F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 1

☐ • 1EB4-2/5F/BKR-2, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 2

☐ d. Momentarily depress the close contactor (42c).

e. WHEN the close contactor opens, THEN OPEN the following breakers:

☐ • 1EB4-2/5F/BKR-1, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 1

☐ • 1EB4-2/5F/BKR-2, SAFETY INJECTION ACCUMULATOR 1-02 INJECT VALVE 1-8808B MOTOR BREAKER 2

[CV] ☐ f. Remove jumper placed in step b above (within 1EB4-2/5F/BKR-1):

- Termination X2
- Termination 7 ______

Verified By: ______

CLOSING ACCUMULATOR ISOLATION VALVES FROM THE MCC

4. Close 1-8808D, SI ACCUM 1-04 INJ VLV from 1EB4-2/5M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-04 INJECT VALVE 1-8808D MOTOR BREAKER 1 (SFGD 852 Rm 1-103) as follows:

   a. Open the following breakers:

   ☐ • 1EB4-2/5M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-04 INJECT VALVE 1-8808D MOTOR BREAKER 1

   ☐ • 1EB4-2/5M/BKR-2, SAFETY INJECTION ACCUMULATOR 1-04 INJECT VALVE 1-8808D MOTOR BREAKER 2

[CV] ☐ b. Within 1EB4-2/5M/BKR-1, place a jumper between the following two terminations: |

   - Termination X2
   - Termination 7 ______

   Verified By: ______

   c. Leaving door open, ensure the following breakers CLOSED.

   ☐ • 1EB4-2/5M/BKR-1, SAFETY INJECTION ACCUMULATOR 1-04 INJECT VALVE 1-8808D MOTOR BREAKER 1

   ☐ • 1EB4-2/5M/BKR-2, SAFETY INJECTION ACCUMULATOR 1-04 INJECT VALVE 1-8808D MOTOR BREAKER 2

☐ d. Momentarily depress the close contactor (42c).

☐ e. WHEN the close contactor opens, THEN OPEN 1EB4-2/5M/BKR-1 AND 1EB4-2/5M/BKR-2

[CV] ☐ f. Remove jumper placed in step b above (within 1EB4-2/5M/BKR-1): |

   - Termination X2
   - Termination 7 ______

   Verified By: ______

☐ 5. Complete signature record:

- Performed by: ____________ / ____________________ / __________
  INITIALS PRINT NAME DATE

- Verified by: ____________ / ____________________ / __________
  INITIALS PRINT NAME DATE

☐ 6. When completed, this attachment shall be dispositioned by attaching it to the Condition Report generated as result of this abnormal condition. |

ATTACHMENT 20
PAGE 1 OF 4

SUPERVISOR CHECKLIST

ESTABLISH CONTROL AT RSP

☐	8	RX TRIP BKRS OPEN (Unit Supervisor) MG SETS (Unit Supervisor) PLANT ANNOUNCEMENT (Unit Supervisor) IMPLEMENT EMERGENCY PLAN (Shift Manager)	
☐	9	VERIFY TURBINE TRIP (PEO)	
☐	10	ISOLATE DILUTION PATHS (PEO) SWAP CHRG PMP SUCT TO RWST (PEO)	
☐	11	ESTABLISH COMMUNICATIONS (RO, RRO)	
☐	13	VERIFY AC POWER AVAILABLE (RO)	
☐	14	XFER/START AFW (PEO)	ACTUAL SG LVL 84% - 92%
☐	15	XFER SG ATMOS RLF VLV's (PEO)	
☐	17	XFER/START SSW (RO) XFER/START CCW (RO) XFER/START SFTY CH WTR (RO)	
☐	25	XFER PRZR PRESS CTRL (RO)	RCS PRESS 2200 - 2300 psig
☐	34	XFER CHRG (RO)	ACTUAL PRZR LVL 25% - 50 %
☐	38	XFER LTDN (RO)	CHRG FLOW 25 - 50 gpm
☐	44	XFER MAIN STEAM (RO)	SG PRESS 1050 - 1150 psig
☐	45	XFER ELECT DIST (RO)	
☐	47	XFER DG (RO, PEO)	
☐	48	XFER ROOM COOLERS (PEO)	

ATTACHMENT 20
PAGE 2 OF 4

SUPERVISOR CHECKLIST

PREPARATION FOR COOLDOWN

☐ 49 XFER REMAINING CTRLS (RO)

☐ 50 MONITOR AND RECORD KEY PARAMETERS (RO)

☐ 51 MONITOR CST LVL (RO)

☐ 52 TRIP RCP's 2 & 3 (PEO)

☐ 54 MAINTAIN THE FOLLOWING LIMITS (RO)

PRZR PRESS	2200 - 2300 psig
ACTUAL PRESS LVL	25 - 50%
SG PRESS	800 - 1150 psig
ACTUAL SG LVL	84 - 92%

☐ 55 SHUTDOWN MARGIN CALCULATION (RO)

☐ 56 MAINTAIN HOT STANDBY UNTIL COOLDOWN DESIRED (RO)

☐ 57 BORATE TO DESIRED TEMPERATURE PLATEAU (RO)

☐ 58 MAINTAIN THE FOLLOWING LIMITS (RO)

SUBCOOLNG	65°F
ACTUAL PRZR LVL	25% - 50%
ACTUAL SG LVL	84% - 92%

ATTACHMENT 20
PAGE 3 OF 4

SUPERVISOR CHECKLIST

COOLDOWN TO COLD SHUTDOWN

> NOTE: I&C must block SI during cooldown phase in the Cable Spreading Room. Contact I&C prior to initiating cooldown.

☐ 59 ENSURE BORATION TO 400°F COMPLETE (RO)

☐ 60 ESTABLISH COOLDOWN RATE LESS THAN 100°F/HR (RO)

RCS PRESS 1900 psig

☐ 61 BLOCK SI (I&C)

☐ 62 ENSURE BORATION TO 300°F COMPLETE (RO)

RCS PRESS 1000 psig

☐ 63 ISOL ACCUMULATORS (EM) OR (PEO, RP)

☐ 64 XFER 1-8702A (PEO)

RCS TEMP 350°F

☐ 65 SIP BKRs (PEO)
NON-OPER CCP BKR (PEO)

☐ 66 RHR RECIRC & SAMPLING (RO, PEO, CHEM)

☐ 67 ENSURE BORATION TO COLD SHUTDOWN COMPLETE (RO)

ATTACHMENT 20
PAGE 4 OF 4

SUPERVISOR CHECKLIST

COOLDOWN TO COLD SHUTDOWN

RCS PRESS 325 - 375 psig

☐ 68 PLACE RHR IN SERVICE (RO, PEO)

☐ 69 TRIP RCP 1 & 4 (PEO)

☐ 71 MAINTAIN RCS PRESS 300 - 400 psig (RO)

☐ 72 ESTABLISH LTDN TO RHT (PEO)

RCS TEMP 250°F

☐ 73 CLOSE ATMOS RLF (RO)
SHUTDOWN AFW (RO)

RCS TEMP 200°F

☐ 74 CTP BKRs (PEO)

ATTEMPT TO REGAIN ACCESS TO CONTROL ROOM

Record of Changes

Rev/PCN	Affected Pages	Description of Change
9/0		Upgrade site name. Incorporate PCNs. Correct nomenclature as identified in FSS Manual Action Feasibility Study. Removed recorder uncertainty from Attachment 13 to be consistent with ABN-803A.
9/1	51	Corrected Attachment 10 title.
9/2	3, 4, 20, 25	Added [C] to 2.3.1.a, 2.3.1.c, caution prior to 2.3.68, and note prior to 2.3.68.g. to reflect commitments which were also added to references. Changed OR to AND step 2.3.1.c.4) to reflect commitment and be consistent with opposite unit procedure.
9/3	41	Annotated Attachment 4, Steps 4 and 5 with [C] to denote incorporated commitment as response to SMF-2009-000748.
9/4	2, 4, 25	Changes are editorial modifications in accordance with SORC approval (Mtg. No. 10-003). 1. Added new reference in 3.2, i.e. STA-919. 2. 2.1 b., 2nd bullet: added reference to the necessity to implement the STA-919 controls. 3. Operator Actions 2.3.6: subdivided existing action statements into two action statements and added 3rd action step to implement the STA-919 controls.
9/5	8	Editorial— step 2.3.14.d corrected 1-HS-2452C to MSL 4 SPLY VLV and corrected 1-HS-2452E to MSL 1 SPLY VLV.
9/6	18 - 24, 57, 66-70	Added Bkr-2's where needed throughout the procedure. (CR-2010-007929)
9/7	6	Added step to dispatch operator to monitor SPDS in the OSC per AI-CR-2011-001575-1.
9/8	7, 25, 43, 44	Added steps to monitor SFP as response to CR-2011-006552.
9/9	1, 4, 45, 50, 52, 53, 67, 68, 69, 70	Added new employee stamp. Modified 2.3.1.c.4) to reflect switch vice valve as the step intends. Added [CV]s to Attachment 6 and 19. Added place keepers for second junction box to Attachment 9. Changed SMF to Condition Report, Attachments 6 and 19. Added switch numbers to Attachment 11, 1 and 2 b. and e.
9/10	1, 4	Added substep for potential cavitation concern to be consistent with other similar procedures.
9/11	1, 7, 25, 43, 44	Added commitment 4163173 to references and annotated applicable step with [C].
9/12	1, 59	Added label to Att.16 that RCS cold leg temperature be used.
9/13	1,59	Corrected footer to Attachment 16- Editorial
9/14	1, 52, 53, 54	Correct nomenclature to match field and similar attachments as response to AI-CR-2014-005765-3.
9/15	1, 25	Editorial on Page 25 Step 3.2 fourth bullet should be Commitment 22880. AI-2016-009427-1.

TECHNICAL SPECIFICATIONS

FOR

COMANCHE PEAK NUCLEAR POWER PLANT

UNITS 1 AND 2

1.0 USE AND APPLICATION

1.1 Definitions

-- NOTE --
The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state required for OPERABILITY of a logic circuit and the verification of the required logic output. The ACTUATION LOGIC TEST, as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of an excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping or total channel steps.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

1.1 Definitions (continued)

CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints required for channel OPERABILITY so that the setpoints are within the necessary range and accuracy. The COT may be performed by means of any series of sequential, overlapping or total channel steps.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries per gram) that alone would produce the same dose when inhaled as the combined activities of iodine isotopes I-131, I-132, I-133, I-134, and I-135 actually present. The determination of DOSE EQUIVALENT I-131 shall be performed using thyroid dose conversion factors from Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites," or from Table E-7 of Regulatory Guide 1.109, Revision 1, NRC, 1977, or from ICRP-30, 1979, Supplement to Part 1, page 192-212, Table titled “Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity,” or from Table 2.1 of EPA Federal Guidance Report No. 11, 1988, “Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion.”

1.1 Definitions (continued)

DOSE EQUIVALENT XE-133	DOSE EQUIVALENT XE-133 shall be that concentration of Xe-133 (microcuries per gram) that alone would produce the same acute dose to the whole body as the combined activities of noble gas nuclides Kr-85m, Kr-87, Kr-88, Xe-133m, Xe-133, Xe-135m, Xe-135, and Xe-138 actually present. If a specific noble gas nuclide is not detected, it should be assumed to be present at the minimum detectable activity. The determination of DOSE EQUIVALENT XE-133 shall be performed using effective dose conversion factors for air submersion listed in Table III.1 of EPA Federal Guidance Report No. 12, 1993, “External Exposure to Radionuclides in Air, Water, and Soil”, or using the dose conversion factors from Table B-1 of Regulatory Guide 1.109, Revision 1, NRC, 1977.
ENGINEERED SAFETY FEATURE (ESF) RESPONSE TIME	The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays, where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

1.1 Definitions (continued)

LEAKAGE

LEAKAGE shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator to the Secondary System (primary to secondary LEAKAGE);

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE;

c. Pressure Boundary LEAKAGE

LEAKAGE (except primary to secondary LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

MASTER RELAY TEST

A MASTER RELAY TEST shall consist of energizing all master relays in the channel required for channel OPERABILITY and verifying the OPERABILITY of each required master relay. The MASTER RELAY TEST shall include a continuity check of each associated required slave relay. The MASTER RELAY TEST may be performed by means of any series of sequential, overlapping or total steps.

MODE

A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

1.1 Definitions (continued)

OPERABLE - OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Chapter 14, of the FSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, the power operated relief valve (PORV) lift settings and the LTOP arming temperature associated with the Low Temperature Overpressurization Protection (LTOP) System, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3458 MWt through Cycle 13 for Unit 1 and through Cycle 11 for Unit 2. Starting with Cycles 14 and 12 of Units 1 and 2, respectively, RTP shall be 3612 MWt.

1.1 Definitions (continued)

REACTOR TRIP SYSTEM (RTS) RESPONSE TIME	The RTS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RTS trip setpoint at the channel sensor until loss of stationary gripper coil voltage. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM; and b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the hot zero power temperatures.
SLAVE RELAY TEST	A SLAVE RELAY TEST shall consist of energizing all slave relays in the channel required for channel OPERABILITY and verifying the OPERABILITY of each required slave relay. The SLAVE RELAY TEST shall include a continuity check of associated testable actuation devices. The SLAVE RELAY TEST may be performed by means of any series of sequential, overlapping or total steps.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

1.1 Definitions (continued)

TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	A TADOT shall consist of operating the trip actuating device and verifying the OPERABILITY of all devices in the channel required for trip actuating device OPERABILITY. The TADOT shall include adjustment, as necessary, of the trip actuating device so that it actuates at the required setpoint within the necessary accuracy. The TADOT may be performed by means of any series of sequential, overlapping or total channel steps.

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTIVITY CONDITION (k_{eff})	% RATED THERMAL POWER[a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Standby	< 0.99	NA	≥ 350
4	Hot Shutdown[b]	< 0.99	NA	$350 > T_{avg} > 200$
5	Cold Shutdown[b]	< 0.99	NA	≤ 200
6	Refueling[c]	NA	NA	NA

(a) Excluding decay heat.
(b) All reactor vessel head closure bolts fully tensioned.
(c) One or more reactor vessel head closure bolts less than fully tensioned.

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE

The purpose of this section is to explain the meaning of logical connectors.

Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TS are AND and OR. The physical arrangement of these connectors constitutes logical conventions with specific meanings.

BACKGROUND

Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentations of the logical connectors.

When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.

EXAMPLES

The following examples illustrate the use of logical connectors.

EXAMPLE 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example the logical connector AND is used to indicate that when in Condition A, both Required Actions A.1 and A.2 must be completed.

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Trip . . . OR A.2.1 Verify . . . AND A.2.2.1 Reduce . . . OR A.2.2.2 Perform . . . OR A.3 Align . . .	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2, and A.3 are alternative choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Actions may be chosen. If A.2 is chosen, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE	The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.
BACKGROUND	Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

Once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

However, when a subsequent train, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the first inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

1.3 Completion Times

DESCRIPTION (continued)

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extensions do not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each train, subsystem, component, or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery . . ."

EXAMPLES

The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-1 (continued)

The Required Actions of Condition B are to be in MODE 3 within 6 hours AND in MODE 5 within 36 hours. A total of 6 hours is allowed for reaching MODE 3 and a total of 36 hours (not 42 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 3 hours, the time allowed for reaching MODE 5 is the next 33 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump inoperable.	A.1 Restore pump to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

When a pump is declared inoperable, Condition A is entered. If the pump is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable pump is restored to OPERABLE status after Condition B is entered, Condition A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

When a second pump is declared inoperable while the first pump is still inoperable, Condition A is not re-entered for the second pump. LCO 3.0.3 is entered, since the ACTIONS do not include a Condition for more than one inoperable pump. The Completion Time clock for Condition A does not stop after LCO 3.0.3 is entered, but continues to be tracked from the time Condition A was initially entered.

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has not expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition A.

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-2 (continued)

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked from the time the Condition A Completion Time expired.

On restoring one of the pumps to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first pump was declared inoperable. This Completion Time may be extended if the pump restored to OPERABLE status was the first inoperable pump. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second pump being inoperable for > 7 days.

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X train inoperable.	A.1 Restore Function X train to OPERABLE status.	7 days
B. One Function Y train inoperable.	B.1 Restore Function Y train to OPERABLE status.	72 hours
C. One Function X train inoperable. AND One Function Y train inoperable.	C.1 Restore Function X train to OPERABLE status. OR C.2 Restore Function Y train to OPERABLE status.	72 hours 72 hours

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X train and one Function Y train are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each train starting from the time each train was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second train was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected train was declared inoperable (i.e., initial entry into Condition A).

It is possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. However, doing so would be inconsistent with the basis of the Completion Times. Therefore, there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended.

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-4 (continued)

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent valve being inoperable for > 4 hours.

If the Completion Time of 4 hours (including the extension) expires while one or more valves are still inoperable, Condition B is entered.

EXAMPLE 1.3-5

ACTIONS

---NOTE---
Separate Condition entry is allowed for each inoperable valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

The Note above the ACTIONS Table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was applicable only to a specific Condition, the Note would appear in that Condition rather than at the top of the ACTIONS Table.

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-5 (continued)

declared inoperable, Condition A is entered and its Completion Time starts. If subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a "once per" Completion Time, which qualifies for the 25% extension, per SR 3.0.2, to each performance after the initial performance. The initial 8 hour interval of Required Action A.1 begins when Condition A is entered and the initial performance of Required Action A.1 must be complete within the first 8 hour interval. If Required Action A.1 is followed, and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-6 (continued)

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

IMMEDIATE COMPLETION TIME

When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR as well as certain Notes in the Surveillance column that modify performance requirements.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the stated Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-1 (continued)

not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Example 1.4-3), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, the Surveillance must be performed within the Frequency requirements of SR 3.0.2 prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of SR 3.0.4.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the 25% extension allowed by SR 3.0.2. "Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-----------------------------NOTE---------------------------- Not required to be performed until 12 hours after ≥ 25% RTP. ---	
Perform channel adjustment.	7 days

The interval continues, whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours with power ≥ 25% RTP.

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 In MODES 1 and 2, the departure from nucleate boiling ratio (DNBR) shall be maintained ≥ the 95/95 DNB criterion for the DNB correlation(s) specified in Section 5.6.5.

2.1.1.2 In MODES 1 and 2, the peak fuel centerline temperature shall be maintained < 4700°F.

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, or 5, restore compliance within 5 minutes.

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2 and LCO 3.0.7.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required unless otherwise stated.

LCO 3.0.3 When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 3 within 7 hours;

b. MODE 4 within 13 hours; and

c. MODE 5 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

LCO 3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time;

3.0 LCO APPLICABILITY

LCO 3.0.4 (continued)

b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate; exceptions to this Specification are stated in the individual Specifications, or

c. When an allowance is stated in the individual value, parameter, or other Specification.

This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

LCO 3.0.5

Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

LCO 3.0.6

When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, an evaluation shall be performed in accordance with Specification 5.5.15, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

3.0 LCO APPLICABILITY (continued)

LCO 3.0.7	Test Exception LCO 3.1.8, allows specified Technical Specification (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Test Exception LCOs is optional. When a Test Exception LCO is desired to be met but is not met, the ACTIONS of the Test Exception LCO shall be met. When a Test Exception LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall be made in accordance with the other applicable Specifications.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1

SRs shall be met during the MODES or other specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

SR 3.0.2

The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.

For Frequencies specified as "once," the above interval extension does not apply.

If a Completion Time requires periodic performance on a "once per . . ." basis, the above Frequency extension applies to each performance after the initial performance.

Exceptions to this Specification are stated in the individual Specifications.

SR 3.0.3

If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance.

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

3.0 SR APPLICABILITY (continued)

SR 3.0.4 Entry into a MODE or other specified condition in the Applicability of an LCO shall only be made when the LCO's Surveillances have been met within their specified Frequency, except as provided by SR 3.0.3. When an LCO is not met due to Surveillances not having been met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with LCO 3.0.4.

This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 SDM shall be within the limits provided in the COLR.

APPLICABILITY: MODE 2 with k_{eff} < 1.0,
MODES 3, 4, and 5

--NOTE--
While this LCO is not met, entry into MODE 5 from MODE 6 is not permitted.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify SDM to be within limits.	In accordance with the Surveillance Frequency Control Program.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Core Reactivity

LCO 3.1.2 The measured core reactivity shall be within ± 1% Δk/k of predicted values.

APPLICABILITY: MODES 1 and 2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Measured core reactivity not within limit.	A.1 Re-evaluate core design and safety analysis, and determine that the reactor core is acceptable for continued operation. <u>AND</u> A.2 Establish appropriate operating restrictions and SRs.	7 days 7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	----------------------------------NOTE---------------------------------- The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading. -- Verify measured core reactivity is within ± 1% $\Delta k/k$ of predicted values.	Once prior to entering MODE 1 after each refueling <u>AND</u> ----------NOTE--------- Only required after 60 EFPD --------------------------- In accordance with the Surveillance Frequency Control Program.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Moderator Temperature Coefficient (MTC)

LCO 3.1.3 The MTC shall be maintained within the limits specified in the COLR. The maximum upper limit shall be that specified in Figure 3.1.3-1.

APPLICABILITY: MODE 1 and MODE 2 with $k_{eff} \geq 1.0$ for the upper MTC limit, MODES 1, 2, and 3 for the lower MTC limit

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. MTC not within upper limit.	A.1 Establish administrative withdrawal limits for control banks to maintain MTC within limit.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2 with $k_{eff} < 1.0$.	6 hours
C. MTC not within lower limit.	C.1 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Verify MTC is within upper limit.	Once prior to entering MODE 1 after each refueling
SR 3.1.3.2	------------------------------NOTES------------------------------ 1. Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. 2. If the MTC is more negative than the 300 ppm Surveillance limit (not LCO limit) specified in the COLR, SR 3.1.3.2 shall be repeated once per 14 EFPD during the remainder of the fuel cycle. 3. SR 3.1.3.2 need not be repeated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of ≤ 60 ppm is less negative than the 60 ppm Surveillance limit specified in the COLR. --- Verify MTC is within lower limit.	Once each cycle

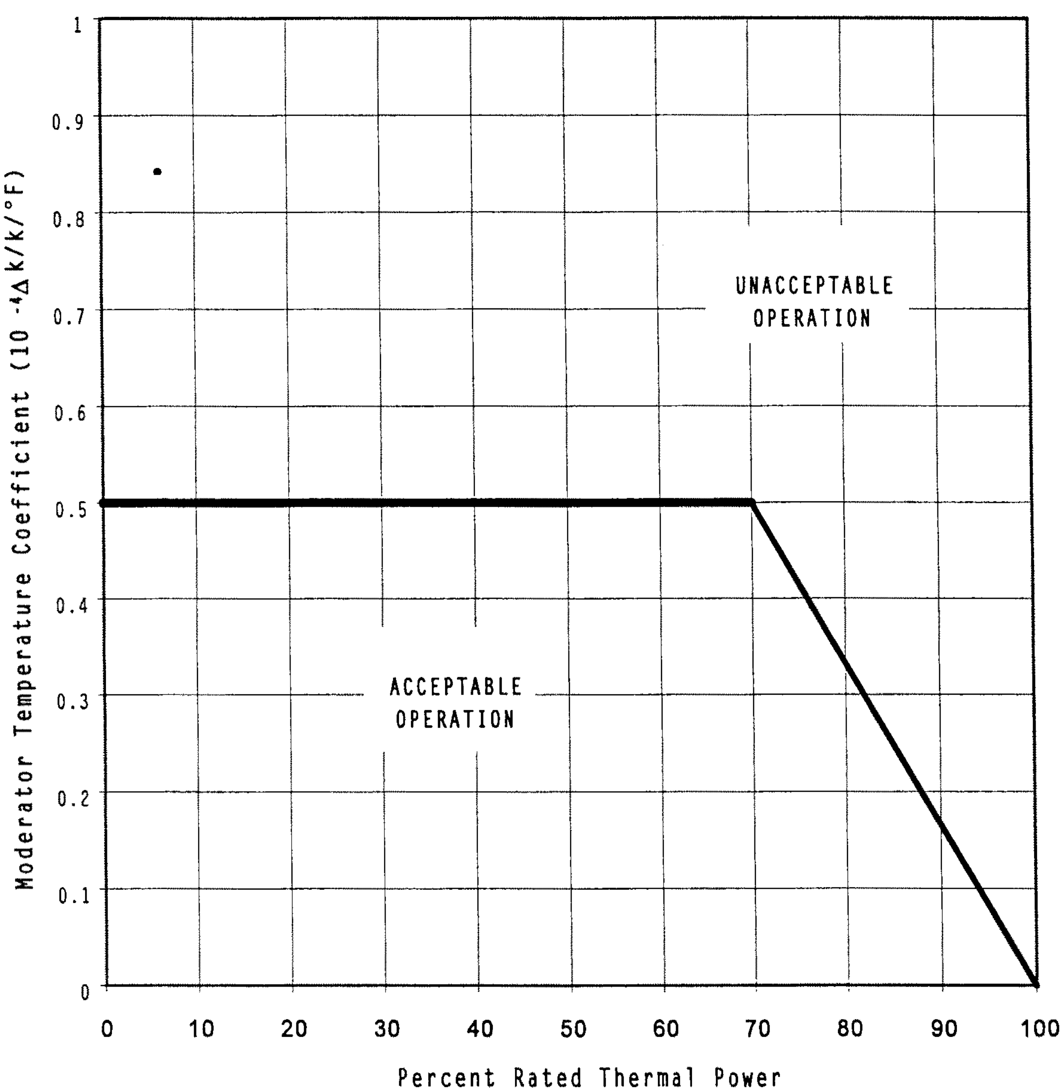


Figure 3.1.3-1 (page 1 of 1)
Moderator Temperature Coefficient vs. Power Level

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE.

AND

Individual indicated rod positions shall be within 12 steps of their group step counter demand position.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) inoperable.	A.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Be in MODE 3.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One rod not within alignment limits.	B.1 Restore rod to within alignment limits.	1 hour
	OR	
	B.2.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	OR	
	B.2.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	B.2.2 Reduce THERMAL POWER to ≤ 75% RTP.	2 hours
	AND	
	B.2.3 Verify SDM to be within the limits provided in the COLR.	Once per 12 hours
	AND	
	B.2.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	72 hours
	AND	
	B.2.5 Perform SR 3.2.2.1.	72 hours
	AND	
	B.2.6 Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	6 hours
D. More than one rod not within alignment limit.	D.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	<u>OR</u>	
	D.1.2 Initiate boration to restore required SDM to within limit.	1 hour
	<u>AND</u>	
	D.2 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify individual rod positions within alignment limit.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core ≥ 10 steps in either direction.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.3	Verify rod drop time of each rod, from the fully withdrawn position, is $\leq$ 2.7 seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. $T_{avg} \geq 500°F$; and b. All reactor coolant pumps operating.	Prior to reactor criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Shutdown Bank Insertion Limits

LCO 3.1.5 Each shutdown bank shall be within insertion limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with any control bank not fully inserted.

---NOTE---
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more shutdown banks not within limits.	A.1.1 Verify SDM to be within the limits provided in the COLR. OR A.1.2 Initiate boration to restore SDM to within limit. AND A.2 Restore shutdown banks to within limits.	1 hour 1 hour 2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each shutdown bank is within the limits specified in the COLR.	In accordance with the Surveillance Frequency Control Program.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Control Bank Insertion Limits

LCO 3.1.6 Control banks shall be within the insertion, sequence, and overlap limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with $k_{eff} \geq 1.0$.

---NOTE---
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control bank insertion limits not met.	A.1.1 Verify SDM to be within the limits provided in the COLR. <u>OR</u> A.1.2 Initiate boration to restore SDM to within limit. <u>AND</u> A.2 Restore control bank(s) to within limits.	1 hour 1 hour 2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Control bank sequence or overlap limits not met.	B.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	OR	
	B.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	B.2 Restore control bank sequence and overlap to within limits.	2 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify estimated critical control bank position is within the limits specified in the COLR.	Within 4 hours prior to achieving criticality
SR 3.1.6.2	Verify each control bank insertion is within the limits specified in the COLR.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.6.3	Verify sequence and overlap limits specified in the COLR are met for control banks not fully withdrawn from the core.	In accordance with the Surveillance Frequency Control Program.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Rod Position Indication

LCO 3.1.7 The Digital Rod Position Indication (DRPI) System and the Demand Position Indication System shall be OPERABLE

APPLICABILITY: MODES 1 and 2.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each inoperable rod position indicator and each demand position indicator per bank.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DRPI per group inoperable for one or more groups.	A.1 Verify the position of the rods with inoperable position indicators indirectly by using core power distribution measurement information.	Once per 8 hours
	OR	
	A.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. More than one DRPI per group inoperable.	B.1 Place the control rods under manual control.	Immediately
	AND	
	B.2 Monitor and record RCS T_{avg}.	Once per 1 hour
	AND	
	B.3 Verify the position of the rods with inoperable position indicators indirectly by using core power distribution measurement information.	Once per 8 hours
	AND	
	B.4 Restore inoperable position indicators to OPERABLE status such that a maximum of one DRPI per group is inoperable.	24 hours
C. One or more rods with inoperable DRPIs have been moved in excess of 24 steps in one direction since the last determination of the rod's position.	C.1 Verify the position of the rods with inoperable position indicators indirectly by using core power distribution measurement information.	4 hours
	OR	
	C.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One demand position indicator per bank inoperable for one or more banks.	D.1.1 Verify by administrative means all DRPIs for the affected banks are OPERABLE.	Once per 8 hours
	AND	
	D.1.2 Verify the most withdrawn rod and the least withdrawn rod of the affected banks are ≤ 12 steps apart.	Once per 8 hours
	OR	
	D.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify each DRPI agrees within 12 steps of the group demand position for the full indicated range of rod travel.	Once prior to criticality after each removal of the reactor vessel head.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 PHYSICS TESTS Exceptions - MODE 2

LCO 3.1.8 During the performance of PHYSICS TESTS, the requirements of

LCO 3.1.3, "Moderator Temperature Coefficient (MTC)";
LCO 3.1.4, "Rod Group Alignment Limits";
LCO 3.1.5, "Shutdown Bank Insertion Limits";
LCO 3.1.6, "Control Bank Insertion Limits"; and
LCO 3.4.2, "RCS Minimum Temperature for Criticality"

may be suspended, provided:

a. RCS lowest operating loop average temperature is ≥ 541°F; and

b. SDM is within the limits provided in the COLR; and

c. THERMAL POWER is ≤ 5% RTP

APPLICABILITY: MODE 2 during PHYSICS TESTS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit. <u>AND</u> A.2 Suspend PHYSICS TESTS exceptions.	15 minutes 1 hour
B. THERMAL POWER not within limit.	B.1 Open reactor trip breakers.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. RCS lowest operating loop average temperature not within limit.	C.1 Restore RCS lowest operating loop average temperature to within limit.	15 minutes
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Perform a CHANNEL OPERATIONAL TEST on power range and intermediate range channels per SR 3.3.1.7, SR 3.3.1.8, and Table 3.3.1-1.	Prior to initiation of PHYSICS TESTS
SR 3.1.8.2	Verify the RCS lowest operating loop average temperature is ≥ 541°F.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.8.3	Verify THERMAL POWER is ≤ 5% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.8.4	Verify SDM is within the limits provided in the COLR.	In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel ($F_Q(Z)$) (RAOC-W(Z) Methodology)

LCO 3.2.1 $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------NOTE--------------- Required Action A.4 shall be completed whenever this Condition is entered. -----------------------------------		
$F_Q^C(Z)$ not within limit.	A.1 Reduce THERMAL POWER ≥ 1% RTP for each 1% $F_Q^C(Z)$ exceeds limit.	15 minutes after each $F_Q^C(Z)$ determination
	<u>AND</u>	
	A.2 Reduce Power Range Neutron Flux--High trip setpoints ≥ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	<u>AND</u>	

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Reduce Overpower N-16 trip setpoints ≥ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	<u>AND</u>	
	A.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------------NOTE-------------- Required Action B.4 shall be completed whenever this Condtion is entered. ------------------------------------		
$F_Q^W(Z)$ not within limits.	B.1 Reduce AFD limits ≥ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	4 hours
	<u>AND</u>	
	B.2 Reduce Power Range Neutron Flux--High trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	<u>AND</u>	
	B.3 Reduce Overpower N-16 trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	<u>AND</u>	
	B.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the maximum allowable power of the AFD limits.
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

---NOTE---
During power escalation following shutdown, THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution measurement is obtained.

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify $F_Q^C(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> Once within 24 hours after achieving equilibrium conditions after exceeding, by ≥ 20% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified <u>AND</u> In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.1.2	---------------------------------NOTE--------------------------------- If $F_Q^C(Z)$ measurements indicate maximum over z $\left[\frac{F_Q^C(Z)}{K(Z)}\right]$ has increased since the previous evaluation of $F_Q^C(Z)$: a. Increase $F_Q^W(Z)$ by an appropriate factor specified in the COLR and reverify $F_Q^W(Z)$ is within limits; or b. Repeat SR 3.2.1.2 once per 7 EFPD until either a. above is met or two successive power distribution measurements indicate maximum over z $\left[\frac{F_Q^C(Z)}{K(Z)}\right]$ has not increased. --	
	Verify $F_Q^W(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.2 (continued)	Once within 24 hours after achieving equilibrium conditions after exceeding, by ≥ 20% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified <u>AND</u> In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

LCO 3.2.2 $F^N_{\Delta H}$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Required Actions A.2 and A.3 must be completed whenever Condition A is entered. ------------------------------------		
$F^N_{\Delta H}$ not within limit.	A.1.1 Restore $F^N_{\Delta H}$ to within limit.	4 hours
	<u>OR</u>	
	A.1.2.1 Reduce THERMAL POWER to < 50% RTP.	4 hours
	<u>AND</u>	
	A.1.2.2 Reduce Power Range Neutron Flux- High trip setpoints to ≤ 55% RTP.	72 hours
	<u>AND</u>	
	A.2 Perform SR 3.2.2.1.	24 hours
	<u>AND</u>	

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 --------------------NOTE-------------------- THERMAL POWER does not have to be reduced to comply with this Required Action. -- Perform SR 3.2.2.1.	Prior to THERMAL POWER exceeding 50% RTP <u>AND</u> Prior to THERMAL POWER exceeding 75% RTP <u>AND</u> 24 hours after THERMAL POWER reaching ≥ 95% RTP
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

--NOTE--
During power escalation following shutdown, THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution measurement is obtained.

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Relaxed Axial Offset Control (RAOC) Methodology)

LCO 3.2.3 The AFD in % flux difference units shall be maintained within the limits specified in the COLR.

--NOTE---
The AFD shall be considered outside limits when two or more OPERABLE excore channels indicate AFD to be outside limits.

APPLICABILITY: MODE 1 with THERMAL POWER $\geq$ 50% RTP

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. AFD not within limits.	A.1 Restore THERMAL POWER to < 50% RTP.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD is within limits for each OPERABLE excore channel.	In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.4 QUADRANT POWER TILT RATIO (QPTR)

LCO 3.2.4 The QPTR shall be ≤ 1.02.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RTP

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. QPTR not within limit.	A.1 Reduce THERMAL POWER ≥ 3% from RTP for each 1% of QPTR >1.00.	2 hours after each QPTR determination
	<u>AND</u>	
	A.2 Determine QPTR.	Once per 12 hours
	<u>AND</u>	
	A.3 Perform SR 3.2.1.1, SR 3.2.1.2 and SR 3.2.2.1.	24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 <u>AND</u> Once per 7 days thereafter
	<u>AND</u>	

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.4 Reevaluate safety analyses and confirm results remain valid for duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>	
	A.5 -------------------NOTES-------------------- 1. Perform Required Action A.5 only after Required Action A.4 is completed. 2. Required Action A.6 shall be completed whenever Required Action A.5 is performed. --- Normalize excore detectors to restore QPTR to within limit.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>	
	A.6 ---------------------NOTE-------------------- Perform Required Action A.6 only after Required Action A.5 is completed. --- Perform SR 3.2.1.1, SR 3.2.1.2 and SR 3.2.2.1.	Within 24 hours after achieving equilibrium conditions at RTP not to exceed 48 hours after increasing THERMAL POWER above the limit of Required Actions A.1
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to ≤ 50% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.2.4.1	------------------------------NOTES------------------------------ 1. With input from one Power Range Neutron Flux channel inoperable and THERMAL POWER ≤ 75% RTP, the remaining three power range channels can be used for calculating QPTR. 2. SR 3.2.4.2 may be performed in lieu of this Surveillance. --- Verify QPTR is within limit by calculation.	In accordance with the Surveillance Frequency Control Program.
SR 3.2.4.2	------------------------------NOTE------------------------------ Not required to be performed until 12 hours after input from one or more Power Range Neutron Flux channels are inoperable with THERMAL POWER > 75% RTP. --- Verify QPTR is within limit using the core power distribution measurement information.	In accordance with the Surveillance Frequency Control Program.

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function.

.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train(s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1 Restore channel to OPERABLE status. <u>OR</u> B.2 Be in MODE 3.	48 hours 54 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. --------------NOTE-------------- While this LCO is not met for Function 19, 20, or 21, in MODE 5, making the Rod Control System capable of rod withdrawal is not permitted. ------------------------------------		
One channel or train inoperable.	C.1 Restore channel or train to OPERABLE status.	48 hours
	<u>OR</u>	
	C.2.1 Initiate action to fully insert all rods.	48 hours
	<u>AND</u>	
	C.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One Power Range Neutron Flux - High channel inoperable.	----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing and setpoint adjustment. --	
	D.1.1 ----------------NOTE------------------ Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. -- Perform SR 3.2.4.2.	12 hours from discovery of THERMAL POWER > 75% RTP <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>	
	D.1.2 Place channel in trip.	72 hours
	<u>OR</u>	
	D.2 Be in MODE 3	78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One channel inoperable.	----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	E.1 Place channel in trip.	72 hours
	<u>OR</u>	
	E.2 Be in MODE 3.	78 hours
F. One Intermediate Range Neutron Flux channel inoperable.	F.1 Reduce THERMAL POWER to < P-6.	24 hours
	<u>OR</u>	
	F.2 Increase THERMAL POWER to > P-10.	24 hours
G. Two Intermediate Range Neutron Flux channels inoperable.	G.1 -----------------NOTE--------------------- Limited boron concentration changes associated with RCS inventory control or limited plant temperature changes are allowed. -- Suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
	G.2 Reduce THERMAL POWER to < P-6.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Not used.		
I. One Source Range Neutron Flux channel inoperable.	------------------------NOTE------------------------ Limited boron concentration changes associated with RCS inventory control or limited plant temperature changes are allowed. -- I.1 Suspend operations involving positive reactivity additions.	 Immediately
J. Two Source Range Neutron Flux channels inoperable.	J.1 Open reactor trip breakers (RTBs).	Immediately
K. One Source Range Neutron Flux channel inoperable.	K.1 Restore channel to OPERABLE status. <u>OR</u> K.2.1 Initiate action to fully insert all rods. <u>AND</u> K.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	48 hours 48 hours 49 hours
L. Not used.		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. One channel inoperable.	-----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	M.1 Place channel in trip.	72 hours
	OR	
	M.2 Reduce THERMAL POWER to < P-7.	78 hours
N. Not used.		
O. One Low Fluid Oil pressure Turbine Trip channel inoperable.	-----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	O.1 Place channel in trip.	72 hours
	OR	
	O.2 Reduce THERMAL POWER to < P-9.	76 hours
P. One or more Turbine Stop Valve Closure Turbine Trip channel(s) inoperable.	P.1 Place channel(s) in trip.	72 hours
	OR	
	P.2 Reduce THERMAL POWER to < P-9.	76 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
Q. One train inoperable.	------------------------NOTE------------------------ One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --	
	Q.1 Restore train to OPERABLE status.	24 hours
	<u>OR</u>	
	Q.2 Be in MODE 3.	30 hours
R. One RTB train inoperable.	------------------------NOTE------------------------ One train may be bypassed for up to 4 hours for surveillance testing or maintenance, provided the other train is OPERABLE. --	
	R.1 Restore train to OPERABLE status.	24 hours
	<u>OR</u>	
	R.2 Be in MODE 3.	30 hours
S. One or more required channel(s) inoperable.	S.1 Verify interlock is in required state for existing unit conditions.	1 hour
	<u>OR</u>	
	S.2 Be in MODE 3.	7 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
T. One or more required channel(s) inoperable.	T.1 Verify interlock is in required state for existing unit conditions. <u>OR</u> T.2 Be in MODE 2.	1 hour 7 hours
U. One trip mechanism inoperable for one RTB.	U.1 Restore inoperable trip mechanism to OPERABLE status. <u>OR</u> U.2 Be in MODE 3.	48 hours 54 hours
V. Not used.		

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.2	----------NOTE---------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 15% RTP. ------------------------------ Compare results of calorimetric heat balance calculation to NIS Power Range channel and N-16 Power Monitor channel outputs. Adjust NIS Power Range channel outputs if calorimetric heat balance calculation exceeds NIS Power Range channel outputs by more than +2% RTP. Adjust N-16 Power Monitor channel outputs if calorimetric heat balance calculation exceeds N-16 Power Monitor channel outputs by more than +2% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.3	----------NOTE---------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. ------------------------------ Compare results of the core power distribution measurements to Nuclear Instrumentation System (NIS) AFD. Adjust NIS channel if absolute difference is ≥ 3%.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.4	----------NOTE---------- This Surveillance must be performed on the reactor trip bypass breaker for the local manual shunt trip only prior to placing the bypass breaker in service. ------------------------------ Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.6	----------NOTE---------- Not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 75% RTP. -------------------- Calibrate excore channels to agree with core power distribution measurements.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.7	----------NOTES---------- 1. Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. 2. Source range instrumentation shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. -------------------- Perform COT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.8	---NOTE--- This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. --- Perform COT.	---NOTE--- Only required when not performed within the previous Frequency specified in the SFCP. --- Prior to reactor startup <u>AND</u> 12 hours after reducing power below P-10 for power and intermediate instrumentation <u>AND</u> Four hours after reducing power below P-6 for source range instrumentation <u>AND</u> In accordance with the Surveillance Frequency Control Program thereafter

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.9	----------------------------------NOTE---------------------------------- Verification of setpoint is not required. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.10	---------------------------------NOTES---------------------------------- 1. N-16 detectors are excluded from CHANNEL CALIBRATION. 2. This Surveillance shall include verification that the time constants are adjusted to the prescribed values. 3. Prior to entry into MODES 2 or 1, N-16 detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 90% RTP. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.11	---------------------------------NOTES--------------------------------- 1. Neutron detectors are excluded from CHANNEL CALIBRATION. 2. This Surveillance shall include verification that the time constants are adjusted to the prescribed values. 3. Prior to entry into MODES 2 or 1, power and intermediate range detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 90% RTP. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.12	Not used.	
SR 3.3.1.13	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.14	----------------------------------NOTE---------------------------------- Verification of setpoint is not required. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.15	-----------------------------------NOTE----------------------------------- Verification of setpoint is not required. -- Perform TADOT.	Prior to exceeding the P-9 interlock whenever the unit has been in MODE 3, if not performed in the previous Frequency specified in the SFCP
SR 3.3.1.16	-----------------------------------NOTE----------------------------------- Neutron and N-16 detectors are excluded from response time testing. -- Verify RTS RESPONSE TIMES are within limits.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.1-1 (page 1 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA
	3[b], 4[b], 5[b]	2	C	SR 3.3.1.14	NA
2. Power Range Neutron Flux					
a. High	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ 109.6% RTP[q][r]
b. Low	1[c], 2	4	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11 SR 3.3.1.16	≤ 25.6% RTP[q][r]
3. Power Range Neutron Flux Rate High Positive Rate	1,2	4	E	SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ 6.3% RTP with time constant ≥ 2 sec
4. Intermediate Range Neutron Flux	1[c], 2[d]	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 31.5% RTP

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.
(c) Below the P-10 (Power Range Neutron Flux) interlock.
(d) Above the P-6 (Intermediate Range Neutron Flux) interlock.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 2 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
5. Source Range Neutron Flux	2[e]	2	I,J	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 1.4 E5 cps
	3[b], 4[b], 5[b]	2	J,K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≤ 1.4 E5 cps
6. Overtemperature N-16	1,2	4	E	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	Refer to Note 1[q][r]
7. Overpower N-16	1,2	4	E	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≤ 112.8% RTP [q][r]
8. Pressurizer Pressure					
a. Low	1[g]	4	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 1863.6 psig (Unit 1) ≥ 1865.2 psig (Unit 2)
b. High	1,2	4	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≤ 2400.8 psig (Unit 1) ≤ 2401.4 psig (Unit 2)

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

(b) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.

(e) Below the P-6 (Intermediate Range Neutron Flux) interlock.

(g) Above the P-7 (Low Power Reactor Trips Block) interlock.

(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 3 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
9. Pressurizer Water Level - High	1[g]	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 93.9% of instrument span
10. Reactor Coolant Flow - Low	1[g]	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 88.6% of indicated loop flow (Unit 1) ≥ 88.8% of indicated loop flow (Unit 2)
11. Not Used					
12. Undervoltage RCPs	1[g]	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 4753 V
13. Underfrequency RCPs	1[g]	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 57.06 Hz
14. Steam Generator (SG) Water Level Low-Low [l]	1, 2	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 37.5% of narrow range instrument span (Unit 1) [q][r] ≥ 34.9% of narrow range instrument span (Unit 2)[q][r]
15. Not Used.					

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(g) Above the P-7 (Low Power Reactor Trips Block) interlock.
(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 4 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
16. Turbine Trip					
a. Low Fluid Oil Pressure	1[(j)]	3	O	SR 3.3.1.10 SR 3.3.1.15	≥ 46.6 psig
b. Turbine Stop Valve Closure	1[(j)]	4	P	SR 3.3.1.10 SR 3.3.1.15	≥ 1% open
17. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	Q	SR 3.3.1.14	NA
18. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2[(e)]	2	S	SR 3.3.1.11 SR 3.3.1.13	≥ 6E-11 amp
b. Low Power Reactor Trips Block, P-7	1	1 per train	T	SR 3.3.1.5	NA
c. Power Range Neutron Flux, P-8	1	4	T	SR 3.3.1.11 SR 3.3.1.13	≤ 50.7% RTP
d. Power Range Neutron Flux, P-9	1	4	T	SR 3.3.1.11 SR 3.3.1.13	≤ 52.7% RTP
e. Power Range Neutron Flux, P-10	1,2	4	S	SR 3.3.1.11 SR 3.3.1.13	≥ 7.3% RTP and ≤ 12.7% RTP
f. Turbine First Stage Pressure, P-13	1	2	T	SR 3.3.1.10 SR 3.3.1.13	≤ 12.7% turbine power
19. Reactor Trip Breakers(RTBs)[(k)]	1,2	2 trains	R	SR 3.3.1.4	NA
	3[(b)], 4[(b)], 5[(b)]	2 trains	C	SR 3.3.1.4	NA

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Contol System capable of rod withdrawal or one or more rods not fully inserted.
(e) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(j) Above the P-9 (Power Range Neutron Flux) interlock.
(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 5 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms[(k)]	1,2	1 each per RTB	U	SR 3.3.1.4	NA
	3[(b)], 4[(b)], 5[(b)]	1 each per RTB	C	SR 3.3.1.4	NA
21. Automatic Trip Logic	1,2	2 trains	Q	SR 3.3.1.5	NA
	3[(b)], 4[(b)], 5[(b)]	2 trains	C	SR 3.3.1.5	NA

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Contol System capable of rod withdrawal or one or more rods not fully inserted.
(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 6 of 6)
Reactor Trip System Instrumentation

Note 1: Overtemperature N-16

The Overtemperature N-16 Function Allowable Values shall not exceed the following setpoint by more than 0.5% N-16 span for N-16 input, 0.5% T_{cold} span for T_{cold} input, 0.5% pressure span for pressure input, and 0.5% Δq span for Δq input.

$$Q_{setpoint} = K_1 - K_2\left[\frac{(1+\tau_1 S)}{(1+\tau_2 S)}T_c - T_c^\circ\right] + K_3(P - P^1) - f_1(\Delta q)$$

Where:

$Q_{setpoint}$ = Overtemperature N-16 trip setpoint

K_1 = *

K_2 = */°F

K_3 = */psig

T_C = Measured cold leg temperature, °F

T_c° = Indicated reference T_C at RATED THERMAL POWER, *°F

P = Measured pressurizer pressure, psig

P^1 ≥ * psig (Nominal RCS operating pressure)

s = the Laplace transform operator, sec^{-1}.

τ_1, τ_2 = Time constants utilized in lead-lag controller for T_c, $\tau_1 \geq$ * sec, and $\tau_2 \leq$ * sec

$f_1(\Delta q)$ = *{($q_t - q_b$) + *%} when ($q_t - q_b$) ≤ *% RTP
0% when *% RTP < ($q_t - q_b$) < *% RTP
*{($q_t - q_b$) - *%} when ($q_t - q_b$) ≥ *% RTP

* as specified in the COLR

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status.	48 hours
	<u>OR</u>	
	B.2.1 Be in MODE 3.	54 hours
	<u>AND</u>	
	B.2.2 Be in MODE 5.	84 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	----------------------NOTE----------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---	
	C.1 Restore train to OPERABLE status.	24 hours
	OR	
	C.2.1 Be in MODE 3.	30 hours
	AND	
	C.2.2 Be in MODE 5.	60 hours
D. One channel inoperable.	----------------------NOTE----------------------- One channel may be bypassed for up to 12 hours for surveillance testing. ---	
	D.1 Place channel in trip.	72 hours
	OR	
	D.2.1 Be in MODE 3.	78 hours
	AND	
	D.2.2 Be in MODE 4.	84 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One Containment Pressure channel inoperable.	----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	E.1 Place channel in bypass.	72 hours
	OR	
	E.2.1 Be in MODE 3.	78 hours
	AND	
	E.2.2 Be in MODE 4.	84 hours
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	F.2.1 Be in MODE 3.	54 hours
	AND	
	F.2.2 Be in MODE 4.	60 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One train inoperable.	----------------------NOTE----------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---	
	G.1 Restore train to OPERABLE status.	24 hours
	OR	
	G.2.1 Be in MODE 3.	30 hours
	AND	
	G.2.2 Be in MODE 4.	36 hours
H. One train inoperable.	----------------------NOTE----------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---	
	H.1 Restore train to OPERABLE status.	24 hours
	OR	
	H.2 Be in MODE 3.	30 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One channel inoperable.	---------------------NOTE--------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	I.1 Place channel in trip.	72 hours
	OR	
	I.2 Be in MODE 3.	78 hours
J. One Main Feedwater Pump trip channel inoperable.	J.1 Place channel in trip.	6 hours
	OR	
	J.2 Be in MODE 3.	12 hours
K. One channel inoperable.	---------------------NOTE--------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	K.1 Place channel in bypass.	72 hours
	OR	
	K.2.1 Be in MODE 3.	78 hours
	AND	
	K.2.2 Be in MODE 5.	108 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One or more required channel(s) inoperable.	L.1 Verify interlock is in required state for existing unit condition.	1 hour
	<u>OR</u>	
	L.2.1 Be in MODE 3.	7 hours
	<u>AND</u>	
	L.2.2 Be in MODE 4.	13 hours

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.3	Not Used.	

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.4	Perform MASTER RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.5	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.6	Perform SLAVE RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.7	---------------------------------NOTES---------------------------------- 1. Verification of relay setpoints not required. 2. Actuation of final devices not included. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.8	----------------------------------NOTE---------------------------------- Verification of setpoint not required for manual initiation functions. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.9	-----------------------------------NOTE----------------------------------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.10	-----------------------------------NOTE----------------------------------- Not required to be performed for the turbine driven AFW pump until 24 hours after SG pressure is ≥ 532 psig. --- Verify ESF RESPONSE TIMES are within limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.11	-----------------------------------NOTE----------------------------------- Verification of setpoint not required. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.2-1 (page 1 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
1. Safety Injection					
a. Manual Initiation	1, 2, 3, 4	2	B	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Containment Pressure -- High 1	1, 2, 3	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 3.8 psig
d. Pressurizer Pressure -- Low	1, 2, 3[b]	4	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 1803.6 psig
e. Steam Line Pressure Low	1, 2, 3[b]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 594.0 psig[c] (Unit 1) ≥ 578.4 psig[c] (Unit 2)
2. Containment Spray					
a. Manual Initiation	1, 2, 3, 4	2 per train, 2 trains	B	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Containment Pressure High -- 3	1, 2, 3	4	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 18.8 psig

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) Above the P-11 (Pressurizer Pressure) interlock and below P-11, unless the Function is blocked.
(c) Time constants used in the lead/lag controller are $T_1 \geq 10$ seconds and $T_2 \leq 5$ seconds.

Table 3.3.2-1 (page 2 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
3. Containment Isolation					
a. Phase A Isolation					
(1) Manual Initiation	1, 2, 3, 4	2	B	SR 3.3.2.8	NA
(2) Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
(3) Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
b. Phase B Isolation					
(1) Manual Initiation	1, 2, 3, 4	2 per train, 2 trains	B	SR 3.3.2.8	NA
(2) Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
(3) Containment Pressure High -- 3	1, 2, 3	4	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9	≤ 18.8 psig

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

Table 3.3.2-1 (page 3 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
4. Steam Line Isolation					
a. Manual Initiation	1, 2[(i)], 3[(i)]	2	F	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays	1, 2[(i)], 3[(i)]	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Containment Pressure -- High 2	1, 2[(i)], 3[(i)]	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 6.8 psig
d. Steam Line Pressure					
(1) Low	1, 2[(i)], 3[(b)(i)]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 594.0 psig[(c)] (Unit 1) ≥ 578.4 psig[(c)] (Unit 2)
(2) Negative Rate -- High	3[(g)(i)]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 178.7 psi[(h)]

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) Above the P-11 (Pressurizer Pressure) Interlock and below P-11, unless the Function is blocked.
(c) Time constants used in the lead/lag controller are $T_1 \geq 10$ seconds and $T_2 \leq 5$ seconds.
(g) Below the P-11 (Pressurizer Pressure) Interlock; however, may be blocked below P-11 when safety injection on steam line pressure-low is not blocked.
(h) Time constant utilized in the rate/lag controller is ≥ 50 seconds.
(i) Except when all MSIVs and their associated upstream drip pot isolation valves are closed and deactivated.

Table 3.3.2-1 (page 4 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
5. Turbine Trip and Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	1, 2[(j)]	2 trains	H	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. SG Water Level -- High High (P-14)	1, 2[(j)]	3 per SG[(p)]	I	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤84.5% of narrow range span (Unit 1) [(q)(r)] ≤82.0% of narrow range span (Unit 2) [(q)(r)]
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

(j) Except when all MFIVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve.

(p) A channel selected for use as an input to the SG water level controller must be declared inoperable.

(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.2-1 (page 5 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays (Solid State Protection System)	1, 2, 3	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. Not Used.					
c. SG Water Level Low-Low	1, 2, 3	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥37.5% of narrow range span (Unit 1) [q][r] ≥34.9% of narrow range span (Unit 2) [q][r]
d. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
e. Loss of Offsite Power	1, 2, 3	1 per train	F	SR 3.3.2.7 SR 3.3.2.9 SR 3.3.2.10	NA
f. Not Used.					
g. Trip of all Main Feedwater Pumps	1, 2	2 per AFW pump	J	SR 3.3.2.8	NA
h. Not Used.					

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.2-1 (page 6 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
7. Automatic Switchover to Containment Sump					
a. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. Refueling Water Storage Tank (RWST) Level - Low Low	1, 2, 3, 4	4	K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 31.9% instrument span
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
8. ESFAS Interlocks					
a. Reactor Trip, P-4	1, 2, 3	1 per train, 2 trains	F	SR 3.3.2.11	NA
b. Pressurizer Pressure, P-11	1, 2, 3	3	L	SR 3.3.2.5 SR 3.3.2.9	≤ 1975.2 psig (Unit 1) ≤ 1976.4 psig (Unit 2)

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.8.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more Functions with two required channels inoperable. OR One required T_{hot} channel and one required Core Exit Temperature channel inoperable. OR One required T_{cold} channel and one required Steam Line Pressure channel for the associated loop inoperable.	C.1 Restore one channel to OPERABLE status.	7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.3-1.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	6 hours 12 hours
F. As required by Required Action D.1 and referenced in Table 3.3.3-1.	F.1 Initiate action in accordance with Specification 5.6.8.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---
SR 3.3.3.1 and SR 3.3.3.3 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.3.2	Deleted	
SR 3.3.3.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITION REFERENCED FROM REQUIRED ACTION D.1
1. Refueling Water Storage Tank Level	2	E
2. Subcooling Monitors	2	E
3. Reactor Coolant System (RCS) Hot Leg Temperature (Wide Range) (T_{hot})	1 per loop	E
4. RCS Cold Leg Temperature (Wide Range) (T_{cold})	1 per loop	E
5. RCS Pressure (Wide Range)	2	E
6. Reactor Vessel Water Level	2[(a)]	F
7. Containment Sump Water Level (Wide Range)	2	E
8. Containment Pressure (Intermediate Range)	2	E
9. Steam Line Pressure	2 per steam line	E
10. Containment Area Radiation (High Range)	2	F
11. Deleted		
12. Pressurizer Water Level	2	E
13. Steam Generator Water Level (Narrow Range)	2 per steam generator	E
14. Condensate Storage Tank Level	2	E
15. Core Exit Temperature - Quadrant 1	2[(c)]	E
16. Core Exit Temperature - Quadrant 2	2[(c)]	E
17. Core Exit Temperature - Quadrant 3	2[(c)]	E
18. Core Exit Temperature - Quadrant 4	2[(c)]	E
19. Auxiliary Feedwater Flow		
a. AFW Flow	2 per steam generator	E
OR		
b. AFW Flow and Steam Generator Water Level (Wide Range)	1 each per steam generator	E

(a) A channel is eight sensors in a probe. A channel is OPERABLE if four or more sensors, one or more in the upper section and three or more in the lower section, are OPERABLE.
(b) Deleted
(c) A channel consists of two core exit thermocouples (CETs).

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown System

LCO 3.3.4 The Remote Shutdown System Functions in Table 3.3.4-1 and the required hot shutdown panel (HSP) controls shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function and required HSP control.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Functions inoperable. <u>OR</u> One or more required HSP controls inoperable.	A.1 Restore required Function and required HSP controls to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2	Verify each required HSP power and control circuit and transfer switch is capable of performing the intended function.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.3	-----------------------------------NOTE----------------------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION for each required instrumentation channel.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.4-1 (page 1 of 1)
Remote Shutdown System Functions

FUNCTION	REQUIRED CHANNELS
1. Neutron Flux Monitors	1
2. Pressurizer Pressure	1
3. RCS Hot Leg Temperature	1 per loop
4. RCS Cold Leg Temperature	1 per loop
5. Condensate Storage Tank Level	1
6. SG Pressure	1 per SG
7. SG Level	1 per SG
8. AFW Flow	1 per SG
9. Pressurizer Level	1
10. Charging Pump to CVCS Charging and RCP Seals Flow Indication	1

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.5 The Loss of Power Diesel Generator Start Instrumentation for each Function in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

---NOTE---
Not applicable for 6.9 kV Preferred Offsite Source Undervoltage function when associated source breaker is open.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE------------- Not applicable to Automatic Actuation Logic and Actuation Relays Function ------------------------------------ One or more Functions with one channel per bus inoperable.	A.1 Place channel in trip.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.	B.1 Restore one channel per bus to OPERABLE status.	1 hour
	<u>OR</u>	
	B.2.1 Declare the Preferred offsite source inoperable.	1 hour
	<u>AND</u>	
	B.2.2 Open associated Preferred offsite source bus breaker.	6 hours
C. Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.	C.1 Restore one channel per bus to OPERABLE status.	1 hour
	<u>OR</u>	
	C.2.1 Declare the Alternate offsite source inoperable.	1 hour
	<u>AND</u>	
	C.2.2 Open associated Alternate offsite source bus breaker.	6 hours
D. Two channels per bus for the 6.9 kV bus loss of voltage function inoperable.	D.1 Restore one channel per bus to OPERABLE status.	1 hour
	<u>OR</u>	
	D.2 Declare the affected A.C. emergency buses inoperable.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two channels per bus for one or more degraded voltage or low grid undervoltage function inoperable	E.1 Restore one channel per bus to OPERABLE status.	1 hour
	<u>OR</u>	
	E.2.1 Declare both offsite power source buses inoperable.	1 hour
	<u>AND</u>	
	E.2.2 Open offsite power source breakers to the associated buses.	6 hours
F. One or more Automatic Actuation Logic and Actuation Relays trains inoperable.	F.1 Restore train(s) to OPERABLE status.	1 hour
G. Required Action and associated Completion Time not met.	G.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.3.5.1	Perform ACTUATION LOGIC TEST.	Prior to entering MODE 4 when in MODE 5 for ≥ 72 hours and if not performed in the previous Frequency specified in the SFCP
SR 3.3.5.2	-----------------------------------NOTE----------------------------------- Setpoint verification is not applicable. --- Perform TADOT.	Prior to entering MODE 4 when in MODE 5 for ≥ 72 hours and if not performed in the previous Frequency specified in the SFCP
SR 3.3.5.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.5.4	Verify LOP DG start ESF RESPONSE TIMES are within limits.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.5-1 (page 1 of 1)
Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Automatic Actuation Logic and Actuation Relays	2 trains	3.3.5.1	NA
2. Preferred offsite source bus undervoltage	2 per bus	3.3.5.2 3.3.5.3	≤ 5580 V and ≥ 5040 V
3. Alternate offsite source bus undervoltage	2 per bus	3.3.5.2 3.3.5.3	≤ 5580 V and ≥ 5040 V
4. 6.9 kv Class 1E bus undervoltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≤ 2115 V
5. 6.9 kv Class 1E bus degraded voltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 6024 V
6. 480 V Class 1E bus low grid undervoltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 439 V
7. 480 V Class 1E bus degraded voltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 439 V

3.3 INSTRUMENTATION

3.3.6 Containment Ventilation Isolation Instrumentation

LCO 3.3.6 The Containment Ventilation Isolation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6-1

ACTIONS

--NOTE--
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One radiation monitoring channel inoperable.	A.1 Restore the affected channel to OPERABLE status.	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------------NOTE------------- Only applicable in MODE 1, 2, 3, or 4. ------------------------------------ One or more Automatic Actuation Logic and Actuation Relays trains inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A not met.	----------------------NOTE----------------------- For Required Action and associated Completion Time of Condition A not met, the containment pressure relief valves may be opened in compliance with the gaseous effluent monitoring instrumentation requirements in Part I of the ODCM. --- B.1 Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves," for containment ventilation isolation valves made inoperable by isolation instrumentation.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. --------------NOTE------------ Only applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. ----------------------------------	-----------------------NOTE------------------------ The containment pressure relief valves may be opened in compliance with the gaseous effluent monitoring instrumentation requirements in Part I of the ODCM. ---	
Required Action and associated Completion Time for Condition A not met.	C.1 Place and maintain containment ventilation valves in closed position.	Immediately
	<u>OR</u>	
	C.2 Enter applicable Conditions and Required Actions of LCO 3.9.4, "Containment Penetrations," for containment ventilation isolation valves made inoperable by isolation instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Ventilation Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.2	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.3	Perform MASTER RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.4	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.5	Perform SLAVE RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.6	Not Used.	
SR 3.3.6.7	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.6-1 (page 1 of 1)
Containment Ventilation Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	1, 2, 3, 4	Refer to LCO 3.3.2 "ESFAS Instrumentation," Functions 2.a and 3.a.1, respectively for all initiation functions and requirements.		
2. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	SR 3.3.6.2 SR 3.3.6.3 SR 3.3.6.5	NA
3. Containment Radiation				
a. Gaseous	1, 2, 3, 4, (b), (c)	1	SR 3.3.6.1 SR 3.3.6.4 SR 3.3.6.7	(a)
4. Containment Isolation - Phase A	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 3.a, for all initiation functions and requirements.			

(a) Must satisfy Gaseous Effluent Dose Rate Requirements in Part I of the ODCM.
(b) During CORE ALTERATIONS.
(c) During movement of irradiated fuel assemblies within containment.

3.3 INSTRUMENTATION

3.3.7 Control Room Emergency Filtration System (CREFS) Actuation Instrumentation

LCO 3.3.7 The CREFS actuation instrumentation for each Function in Table 3.3.7-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.7-1

ACTIONS

--NOTE--
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel or train inoperable.	A.1 Place the affected CREFS train(s) in emergency recirculation mode. <u>OR</u> A.2 --------------------NOTE-------------------- Applicable only to Functions 3a and 3b. -- Secure the Control Room makeup air supply fan from the affected air intake.	7 days 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more Functions with two channels or two trains inoperable.	B.1.1 Place one CREFS train in emergency recirculation mode.	Immediately
	AND	
	B.1.2 Enter applicable Conditions and Required Actions for one CREFS train made inoperable by inoperable CREFS actuation instrumentation	Immediately
	OR	
	B.2 -----------------NOTE------------------ Applicable only to Functions 3a and 3b. ---	
	Secure the Control Room makeup air supply fan from the affected air intake.	Immediately
C. Required Action and associated Completion Time for Condition A or B not met in MODE 1, 2, 3, or 4.	C.1 Be in MODE 3.	6 hours
	AND	
	C.2 Be in MODE 5.	36 hours
D. Required Action and associated Completion Time for Condition A or B not met in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	D.2 Suspend movement of irradiated fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTE--
Refer to Table 3.3.7-1 to determine which SRs apply for each CREFS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.2	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.3	Not Used.	
SR 3.3.7.4	Not Used.	
SR 3.3.7.5	Not Used.	
SR 3.3.7.6	-----------------------------------NOTE----------------------------------- Verification of setpoint is not required. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.7	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.7-1 (page 1 of 1)
CREFS Actuation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	1, 2, 3, 4, 5, and 6, (a)	2 trains	SR 3.3.7.6	NA
2. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4, 5, and 6, (a)	2 trains	SR 3.3.7.2	NA
3. Control Room Radiation				
a. Control Room Air North Intake	1, 2, 3, 4, 5, and 6, (a)	2	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.7	1.4×10^{-4} µCi/ml
b. Control Room Air South Intake	1, 2, 3, 4, 5, and 6, (a)	2	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.7	1.4×10^{-4} µCi/ml
4. Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.			

(a) During movement of irradiated fuel assemblies.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure ≥ the limit specified in the COLR;

b. RCS average temperature ≤ the limit specified in the COLR; and

c. RCS total flow rate ≥ 389,700 gpm and ≥ the limit specified in the COLR.

APPLICABILITY: MODE 1

---NOTE---
Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------------NOTE-------------- Only applicable prior to exceeding 85% RTP after a refueling outage. ------------------------------------ Measured RCS Flow not within limits.	B.1 Maintain THERMAL POWER less than 85% RTP.	Immediately
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is ≥ the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.1.2	Verify RCS average temperature is ≤ the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.1.3	Verify RCS total flow rate is ≥ 389,700 and ≥ the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.4	-----------------------------------NOTE----------------------------------- Not required to be performed until after exceeding 85% RTP after each refueling outage. --- Verify by precision heat balance that RCS total flow rate is ≥ 389,700 and ≥ the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each operating RCS loop average temperature (T_{avg}) shall be ≥ 551°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or more operating RCS loops not within limit.	A.1 Be in MODE 2 with k_{eff} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify RCS T_{avg} in each operating loop ≥ 551°F.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Required Action A.2 shall be completed whenever this Condition is entered. ------------------------------------		
Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1 Restore parameter(s) to within limits.	30 minutes
	<u>AND</u>	
	A.2 Determine RCS is acceptable for continued operation.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	B.2 Be in MODE 5 with RCS pressure < 500 psig.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. --------------NOTE-------------- Required Action C.2 shall be completed whenever this Condition is entered. ------------------------------------		
Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits.	Immediately
	<u>AND</u>	
	C.2 Determine RCS is acceptable for continued operation.	Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.3.1	----------------------------------NOTE---------------------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. --	
	Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops -- MODES 1 and 2

LCO 3.4.4 Four RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify each RCS loop is in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops -- MODE 3

LCO 3.4.5 Two RCS loops shall be OPERABLE, and either:

a. Two RCS loops shall be in operation when the Rod Control System is capable of rod withdrawal; or

b. One RCS loop shall be in operation when the Rod Control System is not capable of rod withdrawal.

---NOTE---
All reactor coolant pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODE 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RCS loop inoperable.	A.1 Restore required RCS loop to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 4.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required RCS loop not in operation, with Rod Control System capable of rod withdrawal.	C.1 Restore required RCS loop to operation. <u>OR</u> C.2 Place the Rod Control System in a condition incapable of rod withdrawal.	1 hour 1 hour
D. Four RCS loops inoperable. <u>OR</u> No RCS loop in operation.	D.1 Place the Rod Control System in a condition incapable of rod withdrawal. <u>AND</u> D.2 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. <u>AND</u> D.3 Initiate action to restore one RCS loop to OPERABLE status and operation.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ 38% (Unit 1) and ≥ 10% (Unit 2) for required RCS loops.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops -- MODE 4

LCO 3.4.6 Two loops consisting of any combination of RCS loops and residual heat removal (RHR) loops shall be OPERABLE, and one loop shall be in operation.

---NOTES---

1. All reactor coolant pumps (RCPs) and RHR pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature ≤ 350°F unless the secondary side water temperature of each steam generator (SG) is ≤ 50°F above each of the RCS cold leg temperatures.

APPLICABILITY: MODE 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required loop inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status. <u>AND</u> A.2 ------------------NOTE---------------------- Only required if one RHR loop is OPERABLE --- Be in MODE 5.	Immediately 24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two required loops inoperable. OR No RCS or RHR loop in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. AND B.2 Initiate action to restore one loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.6.2	Verify SG secondary side water levels are ≥38% (Unit 1) and ≥10% (Unit 2) for required RCS loops.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops -- MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be $\geq$38% (Unit 1) and $\geq$10% (Unit 2).

--NOTES--

1. The RHR pump of the loop in operation may be removed from operation for ≤ 1 hour per 8 hour period provided:

    a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

    b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with any RCS cold leg temperature ≤ 350°F unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable. AND Required SGs secondary side water levels not within limits.	A.1 Initiate action to restore a second RHR loop to OPERABLE status. OR A.2 Initiate action to restore required SG secondary side water levels to within limits.	Immediately Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.7.2	Verify SG secondary side water level is ≥38% (Unit 1) and ≥10% (Unit 2) in required SGs.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops -- MODE 5, Loops Not Filled

LCO 3.4.8 Two residual heat removal (RHR) loops shall be OPERABLE and one RHR loop shall be in operation.

--NOTES--

1. All RHR pumps may be removed from operation for ≤ 1 hour provided:

    a. The core outlet temperature is maintained at least 10°F below saturation temperature.

    b. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

    c. No draining operations to further reduce the RCS water volume are permitted.

2. One RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

APPLICABILITY: MODE 5 with RCS loops not filled

--NOTE--

While this LCO is not met, entry into MODE 5, Loops Not Filled from MODE 5, Loops filled is not permitted.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable.	A.1 Initiate action to restore RHR loop to OPERABLE status.	Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.8.1	Verify one RHR loop is in operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ 92%; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Be in MODE 3.	6 hours
	AND	
	A.2 Fully insert all rods.	6 hours
	AND	
	A.3 Place Rod Control System in a condition incapable of rod withdrawal.	6 hours
	AND	
	A.4 Be in MODE 4.	12 hours
B. One required group of pressurizer heaters inoperable.	B.1 Restore required group of pressurizer heaters to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 92%.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 150 kW.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Three pressurizer safety valves shall be OPERABLE with lift settings $\geq$ 2410 psig and $\leq$ 2485 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures > 320°F

---NOTE--
The lift settings are not required to be within the LCO limits during MODES 3 and 4 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for 54 hours following entry into MODE 3 provided a preliminary cold setting was made prior to heatup.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1 Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. <u>OR</u> Two or more pressurizer safety valves inoperable.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4 with any RCS cold leg temperatures $\leq$ 320°F.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
Separate Condition entry is allowed for each PORV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more PORVs inoperable and capable of being manually cycled.	A.1 Close and maintain power to associated block valve.	1 hour
B. One PORV inoperable and not capable of being manually cycled.	B.1 Close associated block valve.	1 hour
	<u>AND</u>	
	B.2 Remove power from associated block valve.	1 hour
	<u>AND</u>	
	B.3 Restore PORV to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One block valve inoperable.	-----------------------NOTE------------------------ Required Actions do not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2. ---	
	C.1 Place associated PORV in manual control.	1 hour
	AND	
	C.2 Restore block valve to OPERABLE status.	72 hours
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 4	12 hours
E. Two PORVs inoperable and not capable of being manually cycled.	E.1 Close associated block valves.	1 hour
	AND	
	E.2 Remove power from associated block valves.	1 hour
	AND	
	E.3 Be in MODE 3	6 hours
	AND	
	E.4 Be in MODE 4	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. More than one block valve inoperable.	------------------------NOTE------------------------ Required Actions do not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2. ---	
	F.1 Place associated PORVs in manual control.	1 hour
	AND	
	F.2 Restore one block valve to OPERABLE status	2 hours
G. Required Action and associated Completion Time of Condition F not met.	G.1 Be in MODE 3.	6 hours
	AND	
	G.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	---------------------------------NOTES--------------------------------- 1. Not required to be performed with block valve closed in accordance with the Required Action of this LCO. 2. Not required to be performed prior to entry into MODE 3. ---	
	Perform a complete cycle of each block valve.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.2	-----------------------------------NOTE----------------------------------- Not required to be performed prior to entry into MODE 3. --- Perform a complete cycle of each PORV.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP) System

LCO 3.4.12 An LTOP System shall be OPERABLE with a maximum of zero safety injection pumps and two charging pumps capable of injecting into the RCS and the accumulators isolated and one of the following pressure relief capabilities:

a. Two power operated relief valves (PORVs) with lift settings within the limits specified in the PTLR, or

b. Two residual heat removal (RHR) suction relief valves with setpoints $\geq$ 436.5 psig and $\leq$ 463.5 psig, or

c. One PORV with a lift setting within the limits specified in the PTLR and one RHR suction relief valve with a setpoint $\geq$ 436.5 psig and $\leq$ 463.5 psig, or

d. The RCS depressurized and an RCS vent of $\geq$ 2.98 square inches.

---NOTE---
Accumulator may be unisolated when accumulator pressure is less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

APPLICABILITY: MODE 4, MODE 5,
MODE 6 when the reactor vessel head is on

---NOTE---
The LCO is not applicable when all RCS cold leg temperatures are > 320°F and the following conditions are met:

a. At least one reactor coolant pump is in operation, and

b. Pressurizer level is $\leq$ 92%, and

c. The plant heatup rate is limited to 60°F in any one hour period.

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable when entering MODE 4.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more safety injection pumps capable of injecting into the RCS.	A.1 Initiate action to verify a maximum of zero safety injection pumps are capable of injecting into the RCS.	Immediately
B. Three charging pumps capable of injecting into the RCS.	B.1 Initiate action to verify a maximum of two charging pumps are capable of injecting into the RCS.	Immediately
C. An accumulator not isolated when the accumulator pressure is greater than or equal to the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	C.1 Isolate affected accumulator.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Increase RCS cold leg temperature to > 320°F. AND Verify at least one reactor coolant pump is in operation. AND Pressurizer level is ≤ 92%. AND The plant heatup rate is limited to 60°F in any one hour period.	12 hours
	OR	
	D.2 Increase RCS average temperature to > 350°F.	12 hours
	OR	
	D.3 Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	12 hours
E. One required RCS relief valve inoperable in MODE 4.	E.1 Restore required RCS relief valve to OPERABLE status.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One required RCS relief valve inoperable in MODE 5 or 6.	F.1 Restore required RCS relief valve to OPERABLE status.	24 hours
G. Two required RCS relief valves inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A, B, D, E, or F not met. <u>OR</u> LTOP System inoperable for any reason other than Condition A, B, C, D, E, or F.	G.1 Depressurize RCS and establish RCS vent of ≥ 2.98 square inches.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	Verify a maximum of zero safety injection pumps are capable of injecting into the RCS.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.2	Verify a maximum of two charging pumps are capable of injecting into the RCS.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.3	Verify each accumulator is isolated when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.4	Verify RHR suction isolation valves are open for each required RHR suction relief valve.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.5	Verify required RCS vent ≥ 2.98 square inches open.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.6	Verify PORV block valve is open for each required PORV.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.7	Not Used.	
SR 3.4.12.8	---------------------------------NOTE--------------------------------- Not required to be performed until 12 hours after decreasing any RCS cold leg temperature to ≤ 350°F. --- Perform a COT on each required PORV, excluding actuation.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.9	Perform CHANNEL CALIBRATION for each required PORV actuation channel.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

d. 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG).

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists. OR Primary to secondary LEAKAGE not within limits	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	-----NOTES----- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. ---------- Verify RCS operational LEAKAGE is within limits by performance of RCS water inventory balance.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.13.2	-----NOTE----- Not required to be performed until 12 hours after establishment of steady state operation. ---------- Verify primary to secondary LEAKAGE is ≤150 gallons per day through any one SG.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.14 Leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4, except valves in the residual heat removal (RHR) flow path when in, or during the transition to or from, the RHR mode of operation

ACTIONS

---NOTES---

1. Separate Condition entry is allowed for each flow path.

2. Enter applicable Conditions and Required Actions for systems made inoperable by an inoperable PIV.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flow paths with leakage from one or more RCS PIVs not within limit.	----------------------NOTE------------------------ Each valve used to satisfy Required Action A.1 and Required Action A.2 must have been verified to meet SR 3.4.14.1 and be in the reactor coolant pressure boundary or the high pressure portion of the system. --	
	A.1 Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, deactivated automatic, or check valve.	4 hours
	<u>AND</u>	
	A.2.1 Isolate the high pressure portion of the affected system from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve.	72 hours
	<u>OR</u>	
	A.2.2 Restore RCS PIV to within limits.	72 hours
B. Required Action and associated Completion Time for Condition A not met.	B.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	B.2 Be in MODE 5.	36 hours
C. RHR System interlock function inoperable.	C.1 Isolate the affected penetration by use of one closed manual or deactivated automatic valve.	4 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.14.1	------------------------------NOTES------------------------------ 1. Not required to be performed in MODES 3 and 4. 2. Not required to be performed on the RCS PIVs located in the RHR flow path when in the shutdown cooling mode of operation. 3. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. --	
	Verify leakage from each RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.	In accordance with the Inservice Testing Program, and in accordance with the Surveillance Frequency Control Program. AND Prior to entering MODE 2 whenever the unit has been in MODE 5 for 7 days or more, and if leakage testing has not been performed in the previous 9 months except for valves 8701A, 8701B, 8702A and 8702B AND Within 24 hours following check valve actuation due to flow through the valve

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.14.2	Verify RHR System interlock prevents the valves from being opened with a simulated or actual RCS pressure signal $\geq$ 442 psig, except when the valves are open to satisfy LCO 3.4.12.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

a. One Containment Sump Level and Flow Monitoring System;

b. One containment atmosphere particulate radioactivity monitor; and

c. One containment air cooler condensate flow rate monitor or one containment atmosphere radioactivity monitor (gaseous).

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required Containment Sump Level and Flow Monitoring System inoperable.	A.1 -------------------NOTE------------------- Not required until 12 hours after establishment of steady state operation. ---	
	Perform SR 3.4.13.1.	Once per 24 hours
	AND	
	A.2 Restore Containment Sump Level and Flow Monitoring System to OPERABLE status.	30 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required containment atmosphere particulate radioactivity monitor inoperable.	B.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	<u>OR</u>	
	B.1.2 ------------------NOTE------------------ Not required until 12 hours after establishment of steady state operation. --- Perform SR 3.4.13.1.	Once per 24 hours
	<u>AND</u>	
	B.2 Restore required containment atmosphere particulate radioactivity monitor to OPERABLE status.	30 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C Required containment atmosphere gaseous radioactivity monitor inoperable. AND Required containment air cooler condensate flow rate monitor inoperable.	C.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	OR	
	C.1.2 ------------------NOTE------------------ Not required until 12 hours after establishment of steady state operation. --- Perform SR 3.4.13.1.	Once per 24 hours
	AND	
	C.2.1 Restore required containment atmosphere gaseous radioactivity monitor to OPERABLE status.	30 days
	OR	
	C.2.2 Restore required containment air cooler condensate flow rate monitor to OPERABLE status.	30 days
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 5.	36 hours
E. All required monitors inoperable.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.15.1	Perform CHANNEL CHECK of the required containment atmosphere particulate and gaseous radioactivity monitors.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.15.2	Perform COT of the required containment atmosphere particulate and gaseous radioactivity monitors.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required Containment Sump Level and Flow Monitoring System.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.15.4	Perform CHANNEL CALIBRATION of the required containment atmosphere particulate and gaseous radioactivity monitors.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.15.5	Perform CHANNEL CALIBRATION of the required containment air cooler condensate flow rate monitor.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 RCS DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 specific activity shall be within limits.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 not within limit.	----------------------NOTE---------------------- LCO 3.0.4.c is applicable. -- A.1 Verify DOSE EQUIVALENT I-131 $\leq$ 60 μCi/gm. <u>AND</u> A.2 Restore DOSE EQUIVALENT I-131 to within limit.	 Once per 4 hours 48 hours
B. DOSE EQUIVALENT XE-133 not within limit.	B.1 ------------------NOTE------------------ LCO 3.0.4.c is applicable. -- Restore DOSE EQUIVALENT XE-133 to within limit.	 48 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met. <u>OR</u> DOSE EQUIVALENT I-131 > 60 μCi/gm.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	-----------------------------------NOTE----------------------------------- Only required to be performed in MODE 1. -- Verify reactor coolant DOSE EQUIVALENT XE-133 specific activity ≤ 500 μCi/gm.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.16.2	-----------------------------------NOTE-------------------------------- Only required to be performed in MODE 1. --- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 0.45 μCi/gm.	In accordance with the Surveillance Frequency Control Program. <u>AND</u> Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period
SR 3.4.16.3	DELETED	DELETED

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube plugging criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

--NOTES--
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube plugging criteria and not plugged in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND	
	A.2 Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> SG tube integrity not maintained.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.1 Accumulators

LCO 3.5.1 Four ECCS accumulators shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS pressure > 1000 psig.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One accumulator inoperable due to boron concentration not within limits.	A.1 Restore boron concentration to within limits.	72 hours
B. One accumulator inoperable for reasons other than Condition A.	B.1 Restore accumulator to OPERABLE status.	24 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Reduce RCS pressure to 1000 ≤ psig.	6 hours 12 hours
D. Two or more accumulators inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify each accumulator isolation valve is fully open.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.1.2	Verify borated water volume in each accumulator is ≥ 6119 gallons and ≤ 6597 gallons.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.1.3	Verify nitrogen cover pressure in each accumulator is ≥ 623 psig and ≤ 644 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.1.4	Verify boron concentration in each accumulator is ≥ 2300 ppm and ≤ 2600 ppm.	In accordance with the Surveillance Frequency Control Program. <u>AND</u> ----------NOTE--------- Only required to be performed for affected accumulators --------------------------- Once within 6 hours after each solution volume increase of ≥ 101 gallons that is not the result of addition from the refueling water storage tank

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.5	Verify power is removed from each accumulator isolation valve operator when RCS pressure is > 1000 psig.	In accordance with the Surveillance Frequency Control Program.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS -- Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

--NOTES--

1. In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

2. Operation in MODE 3 with ECCS pumps made incapable of injecting, pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is allowed for up to 4 hours or until the temperature of all RCS cold legs exceeds 375°F, whichever comes first.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One train inoperable because of the inoperability of a centrifugal charging pump.	A.1 Restore pump to OPERABLE status.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more trains inoperable for reasons other than one inoperable centrifugal charging pump. AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	B.1 Restore train(s) to OPERABLE status.	72 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position with power to the valve operator removed. Number / Position / Function 8802 A&B — Closed — SI Pump to Hot Legs 8809 A&B — Open — RHR to Cold Legs 8835 — Open — SI Pump to Cold Legs 8840 — Closed — RHR to Hot Legs 8806 — Open — SI Pump Suction from RWST 8813 — Open — SI Pump Miniflow Valve	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2	Verify each ECCS manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.3	Verify ECCS piping is full of water.	Prior to entry into MODE 3
SR 3.5.2.4	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.5.2.5	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.6	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.7	Verify, for each ECCS throttle valve listed below, each mechanical position stop is in the correct position. <u>Valve Number</u> 8810A 8816A 8822A 8810B 8816B 8822B 8810C 8816C 8822C 8810D 8816D 8822D	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.8	Verify, by visual inspection, each ECCS train containment sump suction inlet is not restricted by debris and the suction inlet strainers show no evidence of structural distress or abnormal corrosion.	In accordance with the Surveillance Frequency Control Program.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.3 ECCS -- Shutdown

LCO 3.5.3 One ECCS train shall be OPERABLE.

---NOTE---
An RHR train may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned to the ECCS mode of operation.

APPLICABILITY: MODE 4

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable to ECCS Centrifugal Pump subsystem.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required ECCS residual heat removal (RHR) subsystem inoperable.	A.1 Initiate action to restore required ECCS RHR subsystem to OPERABLE status.	Immediately
B. Required ECCS Centrifugal Charging Pump subsystem inoperable.	B.1 Restore required ECCS Centrifugal Charging Pump subsystem to OPERABLE status.	1 hour
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 5.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	The following SRs are applicable for all equipment required to be OPERABLE: SR 3.5.2.1 SR 3.5.2.4 SR 3.5.2.7 SR 3.5.2.8	In accordance with applicable SRs

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.4 Refueling Water Storage Tank (RWST)

LCO 3.5.4 The RWST shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RWST boron concentration not within limits. OR RWST borated water temperature not within limits.	A.1 Restore RWST to OPERABLE status.	8 hours
B. RWST inoperable for reasons other than Condition A.	B.1 Restore RWST to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	-----------------------------------NOTE----------------------------------- Only required to be performed when ambient air temperature is < 40°F or > 120°F. --- Verify RWST borated water temperature is ≥ 40°F and ≤ 120°F.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.4.2	Verify RWST borated water volume is ≥ 473,731 gallons.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.4.3	Verify RWST boron concentration is ≥ 2400 ppm and ≤ 2600 ppm.	In accordance with the Surveillance Frequency Control Program.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.5 Seal Injection Flow

LCO 3.5.5 Reactor coolant pump seal injection flow shall be ≤ 40 gpm with RCS pressure ≥ 2215 psig and ≤ 2255 psig and the charging flow control valve full open.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Seal injection flow not within limit.	A.1 Adjust manual seal injection throttle valves to give a flow within limit with RCS pressure ≥ 2215 psig and ≤ 2255 psig and the charging flow control valve full open.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.5.1	-----------------------------------NOTE----------------------------------- Not required to be performed until 4 hours after the Reactor Coolant System pressure stabilizes at ≥ 2215 psig and ≤ 2255 psig. --- Verify manual seal injection throttle valves are adjusted to give a flow within limit with RCS pressure ≥ 2215 psig and ≤ 2255 psig and the charging flow control valve full open.	In accordance with the Surveillance Frequency Control Program.

3.6 CONTAINMENT SYSTEMS

3.6.1 Containment

LCO 3.6.1 Containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment inoperable.	A.1 Restore containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1	Perform required visual examinations and leakage rate testing except for containment air lock testing, in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEM

3.6.2 Containment Air Locks

LCO 3.6.2 Two containment air locks shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

---NOTES---

1. Entry and exit is permissible to perform repairs on the affected air lock components.

2. Separate Condition entry is allowed for each air lock.

3. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when air lock leakage results in exceeding the overall containment leakage rate.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment air locks with one containment air lock door inoperable.	-----------------------NOTES---------------------- 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit is permissible for 7 days under administrative controls if both air locks are inoperable. ---	
	A.1 Verify the OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	A.2 Lock the OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>	
	A.3 --------------------NOTE--------------------- Air lock doors in high radiation areas may be verified locked closed by administrative means. -- Verify the OPERABLE door is locked closed in the affected air lock.	Once per 31 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more containment air locks with containment air lock interlock mechanism inoperable.	-----------------------NOTES---------------------- 1. Required Actions B.1, B.2, and B.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit of containment is permissible under the control of a dedicated individual. ---	
	B.1 Verify an OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	B.2 Lock an OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>	
	B.3 ---------------------NOTE-------------------- Air lock doors in high radiation areas may be verified locked closed by administrative means. -- Verify an OPERABLE door is locked closed in the affected air lock.	Once per 31 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	AND	
	C.2 Verify a door is closed in the affected air lock.	1 hour
	AND	
	C.3 Restore air lock to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1	-----------------------------------NOTES-------------------------------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1. -- Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.2.2	Verify only one door in the air lock can be opened at a time.	In accordance with the Surveillance Frequency Control Program.

3.6 CONTAINMENT SYSTEMS

3.6.3 Containment Isolation Valves

LCO 3.6.3 Each containment isolation valve shall be OPERABLE.

---NOTE---
Not applicable to Main Steam Safety Valves (MSSVs), Main Steam Isolation Valves (MSIVs), Feedwater Isolation Valves (FIVs) and Associated Bypass Valves, and Steam Generator Atmospheric Relief Valves (ARVs).

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

--NOTES--

1. Penetration flow path(s) except for 48 inch containment and 12 inch hydrogen purge valve flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by containment isolation valves.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Only applicable to penetration flow paths with two containment isolation valves. ------------------------------------ One or more penetration flow paths with one containment isolation valve inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours
	AND	
	A.2 --------------------NOTES------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. -- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment AND Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ---------------NOTE------------- Only applicable to penetration flow paths with two containment isolation valves. ------------------------------------- One or more penetration flow paths with two containment isolation valves inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------------NOTE------------- Only applicable to penetration flow paths with only one containment isolation valve and a closed system. ------------------------------------ One or more penetration flow paths with one containment isolation valve inoperable.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours
	AND	
	C.2 -------------------NOTES-------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. --- Verify the affected penetration flow path is isolated.	Once per 31 days
D. One or more penetration flow paths with one or more containment purge, hydrogen purge or containment pressure relief valves not within leakage limits.	D.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND	24 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	D.2 --------------------NOTES------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. --- Verify the affected penetration flow path is isolated.	 Once per 31 days for isolation devices outside containment AND Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment
	AND D.3 Perform SR 3.6.3.7 for the resilient seal purge valves closed to comply with Required Action D.1.	 Once per 92 days
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.3.1	Verify each 48 inch Containment Purge and 12 inch Hydrogen Purge valve is sealed closed, except for one purge valve in a penetration flow path while in Condition D of this LCO.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.3.2	Not used.	
SR 3.6.3.3	------------------------------NOTES------------------------------ Valves and blind flanges in high radiation areas may be verified by use of administrative controls. --- Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.3.4	------------------------------NOTES------------------------------ 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. The blind flange on the fuel transfer canal need not be verified closed except after each drainage of the canal. --- Verify each containment isolation manual valve and blind flange that is located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.5	Verify the isolation time of each automatic power operated containment isolation valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.3.6	Not used.	
SR 3.6.3.7	----------------------------------NOTE---------------------------------- This surveillance is not required when the penetration flow path is isolated by a leak tested blank flange. -- Perform leakage rate testing for containment purge, hydrogen purge and containment pressure relief valves with resilient seals.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.3.8	Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.3.9	Not used.	
SR 3.6.3.10	Not used.	
SR 3.6.3.11	Not used.	
SR 3.6.3.12	Not used.	
SR 3.6.3.13	Not used.	

3.6 CONTAINMENT SYSTEMS

3.6.4 Containment Pressure

LCO 3.6.4 Containment pressure shall be ≥ - 0.3 psig and ≤ + 1.3 psig.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment pressure not within limits.	A.1 Restore containment pressure to within limits.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1	Verify containment pressure is within limits.	In accordance with the Surveillance Frequency Control Program.

3.6 CONTAINMENT SYSTEMS

3.6.5 Containment Air Temperature

LCO 3.6.5 Containment average air temperature shall be ≤ 120°F.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment average air temperature not within limit.	A.1 Restore containment average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.5.1	Verify containment average air temperature is within limit.	In accordance with the Surveillance Frequency Control Program.

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System

LCO 3.6.6 Two containment spray trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One containment spray train inoperable.	A.1 Restore containment spray train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 84 hours
C. Two containment spray trains inoperable.	C.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.6.2	Not used.	
SR 3.6.6.3	Not used.	
SR 3.6.6.4	Verify each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.6.6.5	Verify each automatic containment spray valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.6.6	Verify each containment spray pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.6.7	Not used.	
SR 3.6.6.8	Verify each spray nozzle is unobstructed.	Following maintenance which could result in nozzle blockage

3.6 CONTAINMENT SYSTEMS

3.6.7 Spray Additive System

LCO 3.6.7 The Spray Additive System shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spray Additive System inoperable.	A.1 Restore Spray Additive System to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Verify the spray additive system ensures an equilibrium sump pH $\geq$ 7.1 using NaOH.	In accordance with the Technical Requirements Manual

3.7 PLANT SYSTEMS

3.7.1 Main Steam Safety Valves (MSSVs)

LCO 3.7.1 Five MSSVs per steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
Separate Condition entry is allowed for each MSSV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more steam generators with one MSSV inoperable and the Moderator Temperature Coefficient (MTC) zero or negative at all power levels.	A.1 Reduce THERMAL POWER to ≤68% RTP.	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more steam generators with two or more MSSVs inoperable. <u>OR</u> One or more steam generators with one MSSV inoperable and the MTC positive at any power level.	B.1 Reduce Thermal Power to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	4 hours
	<u>AND</u>	
	B.2 --------------------NOTE--------------------- Only required in MODE 1. --- Reduce the Power Range Neutron Flux-High reactor trip setpoint to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	36 hours
C. Required Action and associated Completion Time not met. <u>OR</u> One or more steam generators with ≥ 4 MSSVs inoperable.	C.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	C.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.1.1	-----------------------------------NOTE----------------------------------- Only required to be performed in MODES 1 and 2. ---	
	Verify each required MSSV lift setpoint per Table 3.7.1-2 in accordance with the Inservice Testing Program. Following testing, lift setting shall be within ± 1%.	In accordance with the Inservice Testing Program

Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
4	≤ 61
3	≤ 43
2	≤ 26

Table 3.7.1-2 (page 1 of 1)
Main Steam Safety Valve Lift Settings

VALVE NUMBER				LIFT SETTING (psig ± 3%)
STEAM GENERATOR				
#1	#2	#3	#4	
MS-021	MS-058	MS-093	MS-129	1185
MS-022	MS-059	MS-094	MS-130	1195
MS-023	MS-060	MS-095	MS-131	1205
MS-024	MS-061	MS-096	MS-132	1215
MS-025	MS-062	MS-097	MS-133	1235

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs)

LCO 3.7.2 Four MSIVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 except when all MSIVs are closed and deactivated.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSIV inoperable in MODE 1.	A.1 Restore MSIV to OPERABLE status.	8 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2.	6 hours
C. --------------NOTE-------------- Separate Condition entry is allowed for each MSIV. ------------------------------------- One or more MSIV inoperable in MODE 2 or 3.	C.1 Close MSIV. AND C.2 Verify MSIV is closed.	8 hours Once per 7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	-----------------------------------NOTE----------------------------------- Only required to be performed in MODES 1 and 2. -- Verify the isolation time of each MSIV is within limits.	In accordance with the Inservice Testing Program
SR 3.7.2.2	-----------------------------------NOTE----------------------------------- Only required to be performed in MODES 1 and 2. -- Verify each MSIV actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.3 Feedwater Isolation Valves (FIVs) and Feedwater Control Valves (FCVs) and Associated Bypass Valves

LCO 3.7.3 Four FIVs, four FCVs, and associated bypass valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3 except when FIV, FCV or associated bypass valve is either closed and de-activated or isolated by a closed manual valve.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more FIVs inoperable.	A.1 Close or isolate FIV. <u>AND</u> A.2 Verify FIV is closed or isolated.	72 hours Once per 7 days
B. One or more FCVs inoperable.	B.1 Close or isolate FCV. <u>AND</u> B.2 Verify FCV is closed or isolated.	72 hours Once per 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more FIV or FCV bypass valves inoperable.	C.1 Close or isolate bypass valve. AND C.2 Verify bypass valve is closed or isolated.	72 hours Once per 7 days
D. Two valves in the same flowpath inoperable	D.1 Isolate affected flow path.	8 hours
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify the isolation time of each FIV, FCV, and associated bypass valves is within limits.	In accordance with the Inservice Testing Program
SR 3.7.3.2	Verify each FIV, FCV, and associated bypass valves actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.4 Steam Generator Atmospheric Relief Valves (ARVs)

LCO 3.7.4 Four ARV lines shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ARV line inoperable.	A.1 Restore required ARV line to OPERABLE status.	7 days
B. Two required ARV lines inoperable.	B.1 Restore at least one ARV line to OPERABLE status.	72 hours
C. Three or more required ARV lines inoperable.	C.1 Restore at least two ARV lines to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.4.1	Verify one complete cycle of each ARV.	In accordance with the Inservice testing Program
SR 3.7.4.2	Verify one complete cycle of each ARV block valve.	In accordance with the Inservice testing Program

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW) System

LCO 3.7.5 Three AFW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One steam supply to turbine driven AFW pump inoperable.	A.1 Restore steam supply to OPERABLE status.	7 days
B. One AFW train inoperable for reasons other than Condition A.	B.1 Restore AFW train to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time for Condition A or B not met. OR Two AFW trains inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 18 hours
D. Three AFW trains inoperable.	D.1 -------------------NOTE------------------- LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one AFW train is restored to OPERABLE status. --- Initiate action to restore one AFW train to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.5.1	-----------------------------------NOTE----------------------------------- AFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW mode of operation. -- Verify each AFW manual, power operated, and automatic valve in each water flow path, and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.5.2	-----------------------------------NOTE----------------------------------- Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 532 psig in the steam generator. -- Verify the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice testing Program
SR 3.7.5.3	-----------------------------------NOTE----------------------------------- AFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW mode of operation. -- Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.4	-----NOTES----- 1. Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 532 psig in the steam generator. 2. AFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW operation. ---------- Verify each AFW pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tank (CST)

LCO 3.7.6 The CST level shall be ≥ 53%.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CST level not within limit.	A.1 Verify by administrative means OPERABILITY of backup water supply. AND A.2 Restore CST level to within limit.	4 hours AND Once per 12 hours thereafter 7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the CST level is ≥ 53%.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.7 Component Cooling Water (CCW) System

LCO 3.7.7 Two CCW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CCW train inoperable.	------------------------NOTE------------------------ Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," for residual heat removal loops made inoperable by CCW. -- A.1 Restore CCW train to OPERABLE status.	 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	-----------------------------------NOTE----------------------------------- Isolation of CCW flow to individual components does not render the CCW System inoperable. --- Verify each CCW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.7.2	Verify each CCW automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.7.3	Verify each CCW pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.8 Station Service Water System (SSWS)

LCO 3.7.8 Two SSWS trains and a SSW Pump on the opposite unit with its associated cross-connects shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required SSW Pump on the opposite unit or its associated cross-connects inoperable.	A.1 Restore a SSW Pump on the opposite unit to OPERABLE status. AND A.2 Restore associated cross-connects to OPERABLE status.	7 days 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One SSWS train inoperable.	B.1 --------------------NOTES------------------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources -- Operating," for emergency diesel generator made inoperable by SSWS. 2. Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops -- MODE 4," for residual heat removal loops made inoperable by SSWS. -- Restore SSWS train to OPERABLE status.	 72 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	------------------------------NOTE------------------------------ Isolation of SSWS flow to individual components does not render the SSWS inoperable. -- Verify each SSWS manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.8.2	Verify one complete cycle of each required cross-connect valve that is not locked open.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.8.3	Verify each SSW pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.9 Ultimate Heat Sink (UHS)

LCO 3.7.9 The Safe Shutdown Impoundment (SSI) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SSI level less than required.	A.1 Restore SSI level to within limits.	7 days
B. Required Action and associated Completion Time of Condition A not met. OR SSI inoperable for reasons other than Condition A.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Verify water level of SSI is ≥ 770 ft mean sea level.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.2	Verify station service water intake temperature is $\leq$ 102°F.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.10 Control Room Emergency Filtration/Pressurization System (CREFS)

LCO 3.7.10 Two CREFS trains shall be OPERABLE

-----NOTE-----
The Control Room envelope (CRE) boundary may be opened intermittently under administrative controls.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CREFS train inoperable for reasons other than Condition B.	A.1 Restore CREFS train to OPERABLE status.	7 days
B. One or more CREFS Trains inoperable due to inoperable CRE boundary in MODES 1, 2, 3, and 4.	B.1 Initiate action to implement mitigating actions.	Immediately
	AND	
	B.2 Verify mitigating actions to ensure CRE occupant exposures to radiological, chemical, and smoke hazards will not exceed limits.	24 hours
	AND	
	B.3 Restore CRE boundary to OPERABLE status.	90 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, 3, or 4.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours
D. Required Action and associated Completion Time of Condition A not met in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1 Place OPERABLE CREFS train in emergency recirculation mode. <u>OR</u> D.2.1 Suspend CORE ALTERATIONS. <u>AND</u> D.2.2 Suspend movement of irradiated fuel assemblies.	Immediately Immediately Immediately
E. Two CREFS trains inoperable in MODE 5 or 6, or during movement of irradiated fuel assemblies. <u>OR</u> One or more CREFS trains inoperable due to an inoperable CRE boundary in MODE 5 or 6, or during movement of irradiated fuel assemblies.	E.1 Suspend CORE ALTERATIONS. <u>AND</u> E.2 Suspend movement of irradiated fuel assemblies.	Immediately Immediately
F. Two CREFS trains inoperable in MODE 1, 2, 3, or 4 for reasons other than Condition B.	F.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Operate each CREFS trains Emergency Pressurization Unit for ≥ 10 continuous hours with the heaters operating and Emergency Filtration Unit ≥ 15 minutes.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.10.2	Perform required CREFS testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.10.3	Verify each CREFS train actuates on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.10.4	Perform required CRE unfiltered air inleakage testing in accordance with the Control Room Envelope Habitability Program.	In accordance with the Control Room Envelope Habitability Program

3.7 PLANT SYSTEMS

3.7.11 Control Room Air Conditioning System (CRACS)

LCO 3.7.11 Two CRACS trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CRACS train inoperable.	A.1 Restore CRACS train to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, 3, or 4.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours
C. Required Action and associated Completion Time of Condition A not met in MODE 5, or 6, or during movement of irradiated fuel assemblies.	C.1 Place OPERABLE CRACS train in operation. OR C.2.1 Suspend CORE ALTERATIONS. AND C.2.2 Suspend movement of irradiated fuel assemblies.	Immediately Immediately Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two CRACS trains inoperable in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1.1 Verify at least 100% of the required heat removal capability equivalent to a single OPERABLE train available.	Immediately
	AND	
	D.1.2 Restore the CRACS trains to OPERABLE status.	30 days
	OR	
	D.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	D.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
E. Two CRACS trains inoperable in MODE 1, 2, 3, or 4.	E.1.1 Verify at least 100% of the required heat removal capability equivalent to a single OPERABLE train available.	Immediately
	AND	
	E.1.2 Restore one CRACS train to OPERABLE status.	30 days
	OR	
	E.2 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Verify each CRACS train has the capability to remove the assumed heat load.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.12 Primary Plant Ventilation System (PPVS) - ESF Filtration Trains

LCO 3.7.12 Two PPVS trains shall be OPERABLE

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. With one or more PPVS trains unable to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel Buildings ≥ 0.05 inch water gauge.	A.1 Restore PPVS trains to OPERABLE status.	30 days
B. With one or more PPVS trains unable to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel Buildings ≥ 0.01 inch water gauge.	B.1 Restore ability of PPVS trains to maintain a negative pressure envelope of ≥ 0.01 inch water gauge pressure.	7 days
C. One PPVS train inoperable for any reason except Conditions A or B.	C.1 Restore PPVS train to OPERABLE status.	7 days
D. Required Actions and associated Completion Times not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.12.1	Operate each ESF Filtration train for ≥ 10 continuous hours with the heaters operating.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.12.2	Perform required ESF Filtration Unit filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.12.3	Verify each PPVS train actuates on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.12.4	Verify one PPVS train can maintain a pressure ≤ -0.05 inches water gauge relative to atmospheric pressure during the post accident mode of operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.12.5	Not used.	
SR 3.7.12.6	Verify each PPVS non-ESF fan stops on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.13 Fuel Building Air Cleanup System (FBACS)

NOT USED

3.7 PLANT SYSTEMS

3.7.14 Penetration Room Exhaust Air Cleanup System (PREACS)

NOT USED

3.7 PLANT SYSTEMS

3.7.15 Fuel Storage Area Water Level

LCO 3.7.15 The fuel storage area water level shall be ≥ 23 ft over the top of the storage racks

APPLICABILITY: During movement of irradiated fuel assemblies in a spent fuel storage area.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel storage area water level not within limit.	A.1 ------------------NOTE------------------- LCO 3.0.3 is not applicable. -- Suspend movement of irradiated fuel assemblies in the fuel storage area.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.15.1	Verify the fuel storage area water level is ≥ 23 ft above the top of the storage racks.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.16 Fuel Storage Pool Boron Concentration

LCO 3.7.16 The fuel storage pool boron concentration shall be $\geq$ 2400 ppm.

APPLICABILITY: When fuel assemblies are stored in the fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel storage pool boron concentration not within limit.	------------------------NOTE----------------------- LCO 3.0.3 is not applicable. ---	
	A.1 Suspend movement of fuel assemblies in the fuel storage pool	Immediately
	<u>AND</u>	
	A.2 Initiate action to restore fuel storage pool boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.16.1	Verify the fuel storage pool boron concentration is within limit.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.17 Spent Fuel Assembly Storage

LCO 3.7.17 New or spent fuel assemblies will be stored in compliance with Figure 3.7.17-1.

APPLICABILITY: Whenever any fuel assembly is stored in Region II racks of the spent fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 ------------------NOTE------------------- LCO 3.0.3 is not applicable. --- Initiate action to move fuel as necessary to restore compliance.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.17.1	Verify by administrative means the acceptability of fuel movement plans and the resulting storage configuration in accordance with Figure 3.7.17-1.	Prior to moving a fuel assembly into any Region II storage location.

Figure 3.7.17-1 (page 1 of 3)
Spent Fuel Pool Loading Restrictions

All 2x2 Region II storage cell arrays shall comply with one of the Arrays Definitions below. Each storage location is a corner location for up to 4 separate 2x2 arrays.

A. Arrays II-A through II-E designate the pattern of fuel which may be stored in any 2x2 Array, and are dependent upon Fuel Category.

B. Fuel Categories 1-6 are determined based on Fuel Burnup, Initial Enrichment, Decay Time, and Fuel Group.

C. Fuel Group F1 assemblies have a nominal rod outer diameter of 0.374 inches. Fuel Group F2 assemblies have a nominal rod outer diameter of 0.360 inches.

<table>
<tr><th>Array Definition</th><th colspan="4">Illustration</th></tr>
<tr><td rowspan="2"><u>Array II-A</u>
Category 6 assembly in every cell. Only valid for two rows adjacent to the SFP wall. The two rows adjacent to Array II-A must be Array II-B, and the empty cell in Array II-B must be adjacent to Array II-A.</td><td rowspan="2">W
A
L
L</td><td>6</td><td>6</td><td rowspan="2">Array
II-B</td></tr>
<tr><td>6</td><td>6</td></tr>
</table>

<table>
<tr><td rowspan="2"><u>Array II-B</u>
Cateory 4 fuel assembly in 3 out of 4 cells, with empty cell in the fourth cell.</td><td>4</td><td>4</td></tr>
<tr><td>X</td><td>4</td></tr>
</table>

<table>
<tr><td rowspan="2"><u>Array II-C</u>
Pattern which contains fuel in 3 out of 4 cells, including two diagonally-opposed Category 5 assemblies, one Category 3 assembly, and one empty location. Only Fuel Group F2 assemblies may be stored in Array II-C.</td><td>5</td><td>3</td></tr>
<tr><td>X</td><td>5</td></tr>
</table>

<table>
<tr><td rowspan="2"><u>Array II-D</u>
Checkerboard pattern of two diagonally-opposed Category 2 assemblies with two diagonally-opposed empty cells.</td><td>2</td><td>X</td></tr>
<tr><td>X</td><td>2</td></tr>
</table>

<table>
<tr><td rowspan="2"><u>Array II-E</u>
1 out of 4 storage array, with 3 empty cells.</td><td>X</td><td>X</td></tr>
<tr><td>X</td><td>1</td></tr>
</table>

Figure 3.7.17-1 (page 2 of 3)

Notes:

1. Fuel Categories are ranked in order of relative reactivity, from Category 1 to 6. Fuel Category 1 assemblies have the highest reactivity, and Fuel Category 6 assemblies have the lowest.

2. All Fresh Fuel Assemblies (assemblies with a burnup value of 0.0 MWD/MTU) should be considered Category 1 fuel, independent of Fuel Group or Enrichment.

    a. In Fuel Group F1, Fuel Category 1 is fresh fuel up to 3.5 weight percent U-235 Initial Enrichment.

    b. In Fuel Group F2, Fuel Category 1 is fresh fuel up to 5.0 weight percent U-235 Initial Enrichment.

3. Fuel Category 2 is any Non-Fresh fuel assembly up to 3.5 weight percent U-235 Initial Enrichment (Burnup Requirement is > 0 MWD/MTU).

4. For all other fuel, Fuel Categories are determined as follows:

    a. For Initial Enrichment values below the Minimum Applicable Initial Enrichment values of Table 3.7.17-1, the Fitting Coefficients of Tables 3.7.17-2 and 3.7.17-3 are not applicable. The Minimum Burnup Requirement for the corresponding Category is > 0 MWD/MTU.

    b. For Fuel Group F1 assemblies, determine the Fitting Coefficients A_1 - A_4 using Table 3.7.17-2. Note that Table 3.7.17-2 is only applicable to fuel with $\geq$ 10 years of decay time, and an Initial Enrichment of $\leq$ 3.5 weight percent.

    c. For Fuel Group F2 assemblies, determine the Fitting Coefficients A_1 - A_4 using Table 3.7.17-3.

    d. The required Minimum Burnup value (in MWD/MTU) for each Fuel Category is calculated based on Initial Enrichment (En) and the appropriate fitting coefficients, using the equation below. If the fuel assembly burnup is greater than or equal to the calculated Minimum Burnup value, then the fuel may be classified into this Fuel Category.

    Minimum Burnup = $1{,}000 \times [A_1 \times En^3 + A_2 \times En^2 + A_3 \times En + A_4]$

    e. All relevant uncertainties are explicitly included in the criticality analysis. No additional allowance for burnup uncertainty or initial enrichment uncertainty is required.

Figure 3.7.17-1 (page 3 of 3)

Notes (continued):

f. Conservatively low values of Decay Time may be used to calculate the Minimum Burnup value, or interpolation may be used. If interpolation is used, Minimum Burnup values for tabulated Decay Time values above and below the actual value should first be determined. Next, linear interpolation between these values may be used to determine the Minimum Burnup value. No extrapolation beyond 20 years is permitted.

g. Initial Enrichment (En) is the nominal U-235 weight percent enrichment of the central zone region of fuel, excluding axial blankets, prior to fuel depletion.

h. If the computed Minimum Burnup value $\leq$ 0 MWD/MTU, the Minimum Burnup Requirement is > 0 MWD/MTU.

5. In all Arrays, an assembly with a higher Fuel Category number can be utilized in place of any fuel assembly with a lower Fuel Category Number, with the following exception.

   a. Fuel Group F1 assemblies are not allowed to be stored in Array II-C, regardless of Fuel Category.

6. An empty (water-filled) cell can be substituted for any fuel-containing cell in all storage arrays.

7. Any storage array location designated for a fuel assembly can be replaced with non-fissile hardware. Items other than Fuel Assemblies which contain fissile material are restricted to storage in Region I.

8. Fuel assembly inserts approved for use in the reactor core can be inserted in a stored assembly (in the Spent Fuel Pool) without affecting the fuel category.

Table 3.7.17-1

Minimum Applicable Initial Enrichment for
Table 3.7.17-2 and Table 3.7.17-3 Fitting Coefficients

FUEL CATEGORY	FUEL GROUP F1	FUEL GROUP F2
6	1.25	1.20
5	N/A	1.30
4	1.35	1.45
3	N/A	1.45
2	N/A	3.55

Table 3.7.17-2

Fuel Group F1
Nominal Fuel Rod Outer Diameter of 0.374”

Coefficients to Calculate the Minimum Required Fuel Assembly Burnup (Bu)
as a Function of Decay Time and Initial Enrichment (En)

FUEL CATEGORY	DECAY (YRS)	FITTING COEFFICIENTS			
		A_1	A_2	A_3	A_4
6	10	1.4351	-17.3247	73.3805	-67.4585
6	15	1.7078	-18.7916	74.6322	-67.2637
6	20	0.5289	-9.9969	53.7741	-52.6302
4	10	-0.0444	-1.3474	22.7039	-28.0852
4	15	0.2015	-2.6257	24.1016	-28.2473
4	20	0.4646	-4.1432	26.3891	-29.2170

Note: Fuel must have at least 10 years of decay time and less than or equal to 3.5 weight percent Initial Enrichment to utilize Table 3.7.17-2

Table 3.7.17-3

Fuel Group F2
Nominal Fuel Rod Outer Diameter of 0.360"

Coefficients to Calculate the Minimum Required Fuel Assembly Burnup (Bu)
as a Function of Decay Time and Initial Enrichment (En)

FUEL CATEGORY	DECAY (YRS)	FITTING COEFFICIENTS			
		A_1	A_2	A_3	A_4
6	0	0.5789	-7.4498	42.4056	-41.1591
6	5	0.5247	-6.8992	39.7676	-38.6927
6	10	0.2701	-4.4306	31.9841	-32.4674
6	15	0.3105	-4.5582	31.1825	-31.3916
6	20	0.2374	-3.8754	28.8900	-29.4975
5	0	0.9373	-11.2553	54.7226	-54.1769
5	5	0.6169	-8.1494	44.7801	-45.7968
5	10	0.5380	-7.1852	40.7044	-41.9545
5	15	0.5385	-7.0180	39.2299	-40.3213
5	20	0.5200	-6.7906	38.0244	-39.0979
4	0	0.2553	-3.9826	30.6152	-36.7967
4	5	0.2366	-3.6430	28.2160	-33.9749
4	10	0.4387	-5.6018	33.3609	-37.9327
4	15	0.5450	-6.6302	36.0760	-40.0315
4	20	0.6327	-7.4663	38.2724	-41.7257
3	0	0.5317	-6.1006	32.7118	-36.2263
3	5	0.5228	-5.9434	31.2846	-34.4602
3	10	0.5432	-6.1075	31.1578	-33.9933
3	15	0.5206	-5.8897	30.1768	-32.9600
3	20	0.5158	-5.7796	29.4050	-32.0577
2	0	0.0000	1.6738	-8.5396	9.2206

3.7 PLANT SYSTEMS

3.7.18 Secondary Specific Activity

LCO 3.7.18 The specific activity of the secondary coolant shall be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3. AND A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.18.1	Verify the specific activity of the secondary coolant is ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.19 Safety Chilled Water

LCO 3.7.19 Two safety chilled water trains shall be OPERABLE

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One safety chilled water train inoperable.	A.1 Restore safety chilled water train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.19.1	-----------------------------------NOTE----------------------------------- Isolation of safety chilled water flow to individual components does not render the safety chilled water system inoperable. --- Verify each safety chilled water manual, power operated, and automatic valve servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.19.2	Verify each safety chilled water pump and chiller starts on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.20 UPS HVAC System

LCO 3.7.20 Two UPS HVAC System Trains shall be OPERABLE

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One UPS HVAC System train inoperable.	A.1 Verify the affected UPS & Distribution Room is supported by an OPERABLE UPS A/C Train. AND A.2 Restore the inoperable UPS HVAC train to OPERABLE status.	Immediately 30 days
B. Two UPS HVAC System trains inoperable. OR Required Action A.1 and associated Completion Time not met.	B.1 Verify air circulation is maintained by at least one UPS A/C Train. AND B.2 Verify the air temperature in the affected UPS & Distribution Room(s) does not exceed the maximum temperature limit for the room(s). AND B.3 Restore UPS HVAC System train to OPERABLE status.	Immediately 12 hours AND Once per 12 hours thereafter 72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action B.1 and associated Completion Time not met.	C.1 Restore the required support.	1 hour
D. Required Action and associated Completion Time of Required Action A.2, B.2, B.3 or C.1 not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.20.1	Verify each required UPS & Distribution Room Fan Coil Unit operates ≥ 1 continuous hour.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.20.2	Verify each required UPS A/C train operates for ≥ 1 continuous hour.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.20.3	Verify each required UPS A/C train actuates on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources -- Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System;

b. Two diesel generators (DGs) capable of supplying the onsite Class 1E power distribution subsystem(s); and

c. Automatic load sequencers for Train A and Train B.

APPLICABILITY: MODES 1, 2, 3, and 4

--NOTE---
One DG may be synchronized with the offsite power source under administrative controls for the purpose of surveillance testing.

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 --------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. --- Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND	
	A.3 Restore required offsite circuit to OPERABLE status.	72 hours OR 14 days for a one-time outage on XST1 to complete a plant modification to be completed by March 31, 2017.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One DG inoperable.	B.1 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	B.2 ---------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. --- Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.3.1 Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	OR	
	B.3.2 -------------------NOTE------------------- The SR need not be performed if the DG is already operating and loaded. --- Perform SR 3.8.1.2 for OPERABLE DG(s).	 24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND	
	B.4 Restore DG to OPERABLE status.	72 hours
C. Two required offsite circuits inoperable.	C.1 --------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. --	
	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND	
	C.2 Restore one required offsite circuit to OPERABLE status.	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required offsite circuit inoperable. AND One DG inoperable.	----------------------NOTE---------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition D is entered with no AC power source to any train. --	
	D.1 Restore required offsite circuit to OPERABLE status.	12 hours
	OR	
	D.2 Restore DG to OPERABLE status.	12 hours
E. Two DGs inoperable.	E.1 Restore one DG to OPERABLE status.	2 hours
F. One SI sequencer inoperable.	F.1 -------------------NOTE-------------------- One required SI sequencer channel may be bypassed for up to 4 hours for surveillance testing provided the other channel is operable. ---	
	Restore SI sequencer to OPERABLE status.	24 hours
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1 Be in MODE 3.	6 hours
	AND	
	G.2 Be in MODE 5.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Three or more required AC sources inoperable.	H.1 Enter LCO 3.0.3.	Immediately
I. One Blackout Sequencer inoperable	I.1 Declare associated DG inoperable	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.2	---------------------------------NOTES--------------------------------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. -- Verify each DG starts from standby conditions and achieves steady state voltage $\geq$ 6480 V and $\leq$ 7150 V, and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	-----------------------------------NOTES----------------------------------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2 or SR 3.8.1.7. -- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 6300 kW and ≤ 7000 kW.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.4	Verify each day tank contains ≥ 1440 gal of fuel oil.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank to the day tank.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.7	-----------------------------------NOTE----------------------------------- All DG starts may be preceded by an engine prelube period. --- Verify each DG starts from standby condition and achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz; and b. steady state, voltage ≥ 6480 V and ≤ 7150 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.8	-----------------------------------NOTE----------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify automatic and manual transfer of AC power sources from the normal offsite circuit to each alternate required offsite circuit.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-----------------------------------NOTE----------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 66.75 Hz; and b. Within 3 seconds following load rejection, the voltage is ≥ 6480 V and ≤ 7150 V.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.10	Verify each DG does not trip and voltage is maintained ≤ 8280 V during and following a load rejection of ≥ 6300 kW and ≤ 7000 kW.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	---NOTES--- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in $\leq$10 seconds, 2. energizes auto-connected shutdown loads through automatic load sequencer, 3. maintains steady state voltage $\geq$ 6480 V and $\leq$ 7150 V, 4. maintains steady state frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	-----------------------------------NOTE----------------------------------- All DG starts may be preceded by prelube period. --- Verify on an actual or simulated Safety Injection (SI) actuation signal each DG auto-starts from standby condition and; a. in ≤ 10 seconds after auto-start and during tests, achieves voltage ≥ 6480 V and frequency ≥ 58.8 Hz; b. Achieves steady state voltage ≥ 6480 V and ≤ 7150 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; c. Operates for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.13	-----------------------------------NOTE----------------------------------- For Unit 2, testing need only be performed for LOOP concurrent with SI until startup following 2RFO5. --- Verify each DG's automatic trips are bypassed on actual or simulated (i) loss of voltage signal on the emergency bus, and (ii) SI actuation signal, except: a. Engine overspeed; and b. Generator differential current.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	-----NOTE----- Momentary transients outside the load and power factor ranges do not invalidate this test. ----- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 6900 kW and ≤ 7700 kW; and b. For the remaining hours of the test loaded ≥ 6300 kW and ≤ 7000 kW.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.15	-----NOTES----- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 6300 kW and ≤ 7000 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ----- Verify each DG starts and achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz; and b. steady state, voltage ≥ 6480 V and ≤ 7150 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	------------------------------NOTE------------------------------ This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.17	------------------------------NOTE------------------------------ This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated SI actuation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.18	------------------------------NOTE------------------------------ This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. ---	
	Verify interval between each sequenced load block is within ± 10% of design interval for each automatic load sequencer.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	---NOTES--- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated SI actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in $\leq$ 10 seconds, 2. energizes auto-connected emergency loads through load sequencer, 3. achieves steady state voltage $\geq$ 6480 V and $\leq$ 7150 V, 4. achieves steady state frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ------------------------------ Verify when started simultaneously from standby condition, each DG achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz, and b. steady state, voltage ≥ 6480 V, and ≤ 7150 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.21	Calibrate BO sequencers.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.22	----------NOTES---------- 1. Verification of setpoint is not required. 2. Actuation of final devices is not included. ------------------------------ Perform TADOT for SI and BO sequencers.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources -- Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem required by LCO 3.8.10, "Distribution Systems -- Shutdown"; and

b. One diesel generator (DG) capable of supplying one train of the onsite Class 1E AC electrical power distribution subsystems required by LCO 3.8.10.

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	------------------------NOTE----------------------- Enter applicable Conditions and Required Actions of LCO 3.8.10, with the required train de-energized as a result of Condition A. ---	
	A.1 Declare affected required feature(s) with no offsite power available inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	<u>AND</u>	
	A.2.4 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required DG inoperable.	B.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	B.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	B.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	B.4 Initiate action to restore required DG to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
---NOTE--- The following SRs are not required to be performed: SR 3.8.1.3, SR 3.8.1.9 through SR 3.8.1.11, SR 3.8.1.14, SR 3.8.1.15, and SR 3.8.1.16.		
SR 3.8.2.1	For AC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.1.1 SR 3.8.1.5 SR 3.8.1.10 SR 3.8.1.2 SR 3.8.1.6 SR 3.8.1.11 (except c.2) SR 3.8.1.3 SR 3.8.1.7 SR 3.8.1.14 SR 3.8.1.4 SR 3.8.1.9 SR 3.8.1.15 SR 3.8.1.16	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more DGs with fuel level < a 7 day supply and > a 6 day supply in storage tank.	A.1 Restore fuel oil level to within limits.	48 hours
B. One or more DGs with lube oil inventory < a 7 day supply and > a 2 day supply.	B.1 Restore lube oil inventory to within limits.	48 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more DGs with stored fuel oil total particulates not within limit.	C.1 Restore fuel oil total particulates within limit.	7 days
D. One or more DGs with new fuel oil properties not within limits.	D.1 Restore stored fuel oil properties to within limits.	30 days
E. Required Action and associated Completion Time not met. OR One or more DGs diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than Condition A, B, C or D.	E.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains ≥ a 7 day supply of fuel.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.2	-----------------------------------NOTE----------------------------------- Not required to be performed until the engine has been shutdown for > 10 hours. --- Verify lubricating oil inventory is ≥ a 7 day supply	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.4	Verify each required DG air start receiver pressure is ≥ 180 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources -- Operating

LCO 3.8.4 The Train A and Train B DC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two required battery chargers on one train inoperable.	A.1 Restore affected battery(ies) terminal voltage to greater than or equal to the minimum established float voltage.	2 hours
	<u>AND</u>	
	A.2 Verify affected battery(ies) float current $\leq$ 2 amps.	Once per 12 hours
	<u>AND</u>	
	A.3 Restore required battery charger(s) to OPERABLE status.	7 days
B. One or two batteries on one train inoperable.	B.1 Restore affected battery(ies) to OPERABLE status.	2 hours
C. One DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore DC electrical power subsystem to OPERABLE status.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and Associated Completion Time not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is greater than or equal to the minimum established float voltage.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.4.2	Verify each battery charger supplies ≥ 300 amps at greater than or equal to the minimum established charger test voltage for ≥ 8 hours. <u>OR</u> Verify each battery charger can recharge the battery to the fully charged state within 24 hours while supplying the largest combined demands of the various continuous steady state loads, after a battery discharge to the bounding design basis event discharge state.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.3	----------NOTES---------- 1. The modified performance discharge test in SR 3.8.6.6 may be performed in lieu of SR 3.8.4.3. 2. Verify requirement during MODES 3, 4, 5, 6 or with core off-loaded. ----------------------------- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources -- Shutdown

LCO 3.8.5 The Train A or Train B DC electrical power subsystem shall be OPERABLE to support one train of the DC electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems -- Shutdown."

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required DC electrical power subsystems inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	<u>AND</u>	
	A.2.4 Initiate action to restore required DC electrical power subsystem to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.5.1	-----------------------------------NOTE----------------------------------- The following SRs are not required to be performed: SR 3.8.4.2 and SR 3.8.4.3. --- For DC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.4.1 SR 3.8.4.2 SR 3.8.4.3.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Parameters

LCO 3.8.6 Battery parameters for Train A and Train B batteries shall be within limits.

APPLICABILITY: When associated DC electrical power subsystems are required to be OPERABLE.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two batteries on one train with one or more battery cells float voltage < 2.07 V.	A.1 Perform SR 3.8.4.1	2 hours
	<u>AND</u>	
	A.2 Perform SR 3.8.6.1	2 hours
	<u>AND</u>	
	A.3 Restore affected cell(s) float voltage ≥ 2.07 V.	24 hours
B. One or two batteries on one train with float current > 2 amps.	B.1 Perform SR 3.8.4.1	2 hours
	<u>AND</u>	
	B.2 Restore affected battery(ies) float current to ≤ 2 amps.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------------NOTE------------ Required Action C.2 shall be completed if electrolyte level was below the top of plates. -----------------------------------	------------------------NOTE----------------------- Required Actions C.1 and C.2 are only applicable if electrolyte level was below the top of plates. ---	
One or two batteries on one train with one or more cells electrolyte level less than minimum established design limits.	C.1 Restore affected cell(s) electrolyte level to above the top of the plates.	8 hours
	<u>AND</u>	
	C.2 Verify no evidence of leakage.	12 hours
	<u>AND</u>	
	C.3 Restore affected cell(s) electrolyte level to greater than or equal to minimum established design limits.	31 days
D. One or two batteries on one train with pilot cell electrolyte temperature less than minimum established design limits.	D.1 Restore battery pilot cell(s) electrolyte temperature to greater than or equal to minimum established design limits.	12 hours
E. One or more batteries in redundant trains with battery parameters not within limits.	E.1 Restore battery parameters for batteries in one train to within limits.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met. OR One or two batteries on one train with one or more battery cells float voltage < 2.07 V and float current > 2 amps.	F.1 Declare associated battery(ies) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.6.1	-----------------------------------NOTE----------------------------------- Not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1 --- Verify each battery float current is ≤ 2 amps.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.2	Verify each battery pilot cell voltage is ≥ 2.07 V.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3	Verify each battery connected cell electrolyte level is greater than or equal to minimum established design limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.4	Verify each battery pilot cell temperature is greater than or equal to minimum established design limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.5	Verify each battery connected cell voltage is ≥ 2.07 V.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.6.6	-----------------------------------NOTE----------------------------------- Verify requirement during MODES 3, 4, 5, 6 or with core off-loaded. --	
	Verify battery capacity is $\geq$ 80 % of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	In accordance with the Surveillance Frequency Control Program. <u>AND</u> 18 months when battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating <u>AND</u> 24 months when battery has reached 85% of the expected life with capacity $\geq$ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters -- Operating

LCO 3.8.7 The required Train A and Train B inverters shall be OPERABLE.

---NOTE---
Inverters may be disconnected from one DC bus for ≤ 24 hours to perform an equalizing charge on their associated common battery, provided:

a. The associated AC vital bus(es) are energized; and

b. All other AC vital buses are energized from their associated OPERABLE inverters.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required inverter inoperable.	A.1 ---------------------NOTE-------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any vital bus de-energized. -- Restore inverter to OPERABLE status.	 24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct inverter voltage, and alignment to required AC vital buses.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 IInverters Shutdown

LCO 3.8.8 The Train A or Train B inverters shall be OPERABLE to support one train of the onsite Class 1E AC vital bus electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems -- Shutdown."

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required inverters inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	<u>AND</u>	
	A.2.4 Initiate action to restore required inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct inverter voltage and alignments to required AC vital buses.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems -- Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours
B. One AC vital bus subsystem inoperable.	B.1 Restore AC vital bus subsystem to OPERABLE status.	2 hours
C. One DC electrical power distribution subsystem inoperable.	C.1 Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours
E. Two trains with inoperable distribution subsystems that result in a loss of safety function.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.10 Distribution Systems -- Shutdown

LCO 3.8.10 The necessary portion of the Train A or Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE to support one train of equipment required to be OPERABLE.

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required AC, DC, or AC vital bus electrical power distribution subsystems inoperable.	A.1 Declare associated supported required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	<u>AND</u>	

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate actions to restore required AC, DC, and AC vital bus electrical power distribution subsystems to OPERABLE status. AND A.2.5 Declare associated required residual heat removal subsystem(s) inoperable and not in operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.10.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.1 Boron Concentration

LCO 3.9.1 Boron concentrations of all filled portions of the Reactor Coolant System, the refueling canal, and the refueling cavity, that have direct access to the reactor vessel, shall be maintained within the limit specified in the COLR.

---NOTE--
While this LCO is not met, entry into MODE 6 from MODE 5 is not permitted.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Boron concentration not within limit.	A.1 Suspend CORE ALTERATIONS. AND A.2 Suspend positive reactivity additions. AND A.3 Initiate action to restore boron concentration to within limit.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Verify boron concentration is within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.2 Unborated Water Source Isolation Valves

LCO 3.9.2 Each valve used to isolate unborated water sources shall be secured in the closed position.

APPLICABILITY: MODE 6.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each unborated water source isolation valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Required Action A.4 must be completed whenever Condition A is entered. ----------------------------------- One or more valves not secured in closed position.	A.1 Suspend CORE ALTERATIONS. AND A.2 Suspend positive reactivity addition. AND A.3 Initiate actions to secure valve in closed position. AND A.4 Perform SR 3.9.1.1.	Immediately Immediately Immediately 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify each valve that isolates unborated water sources is secured in the closed position.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.3 Nuclear Instrumentation

LCO 3.9.3 Two source range neutron flux monitors shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required source range neutron flux monitor inoperable.	A.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
B. Two required source range neutron flux monitors inoperable.	B.1 Initiate action to restore one source range neutron flux monitor to OPERABLE status.	Immediately
	AND	
	B.2 Perform SR 3.9.1.1.	Once per 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.9.3.2	---------------------------------NOTE-------------------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.4 Containment Penetrations

LCO 3.9.4 The containment penetrations shall be in the following status:

a. The equipment hatch closed and held in place by four bolts, or if open, capable of being closed;

b. One door in the emergency air lock closed and one door in the personnel airlock capable of being closed; and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere either:

1. closed by a manual or automatic isolation valve, blind flange, or equivalent, or

2. capable of being closed by an OPERABLE containment ventilation isolation valve.

---NOTE--

Penetration flow path(s) providing direct access from the containment atmosphere to the outside atmosphere may be unisolated under administrative controls.

APPLICABILITY: During CORE ALTERATIONS,
During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment penetrations not in required status.	A.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.9.4.1	Verify each required containment penetration is in the required status.	In accordance with the Surveillance Frequency Control Program.
SR 3.9.4.2	--------------------------------NOTE-------------------------------- Only required for an open equipment hatch -- Verify the capability to install the equipment hatch.	 In accordance with the Surveillance Frequency Control Program.
SR 3.9.4.3	Verify each required containment ventilation isolation valve actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.5 Residual Heat Removal (RHR) and Coolant Circulation -- High Water Level

LCO 3.9.5 One RHR loop shall be OPERABLE and in operation.

-----NOTE-----
The required RHR loop may be removed from operation for ≤ 1 hour per 8 hour period, provided no operations are permitted that would cause introduction of coolant into the Reactor Coolant System with boron concentration less than that required to meet the minimum required boron concentration of LCO 3.9.1.

APPLICABILITY: MODE 6 with the water level ≥ 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RHR loop requirements not met.	A.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
	AND	
	A.2 Suspend loading irradiated fuel assemblies in the core.	Immediately
	AND	
	A.3 Initiate action to satisfy RHR loop requirements.	Immediately
	AND	
	A.4 Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	Verify one RHR loop is in operation and circulating reactor coolant at a flow rate of ≥ 3800 gpm.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.6 Residual Heat Removal (RHR) and Coolant Circulation -- Low Water Level

LCO 3.9.6 Two RHR loops shall be OPERABLE, and one RHR loop shall be in operation.

---NOTE--
While this LCO is not met, entry into a MODE or other specified condition in the Applicability is not permitted.

APPLICABILITY: MODE 6 with the water level < 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Less than the required number of RHR loops OPERABLE.	A.1 Initiate action to restore required RHR loops to OPERABLE status.	Immediately
	<u>OR</u>	
	A.2 Initiate action to establish ≥ 23 ft of water above the top of reactor vessel flange.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. No RHR loop in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
	<u>AND</u>	
	B.2 Initiate action to restore one RHR loop to operation.	Immediately
	<u>AND</u>	
	B.3 Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify one RHR loop is in operation and circulating reactor coolant at a flow rate of ≥ 1000 gpm.	In accordance with the Surveillance Frequency Control Program.
SR 3.9.6.2	Verify correct breaker alignment and indicated power available to the required RHR pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.7 Refueling Cavity Water Level

LCO 3.9.7 Refueling cavity water level shall be maintained ≥ 23 ft above the top of reactor vessel flange.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refueling cavity water level not within limit.	A.1 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify refueling cavity water level is ≥ 23 ft above the top of reactor vessel flange.	In accordance with the Surveillance Frequency Control Program.

4.0 DESIGN FEATURES

4.1 Site Location

The site area is approximately 7,700 acres located in Somervell County in North Central Texas. Squaw Creek Reservoir (SCR), established for station cooling, extends into Hood County. The site is situated along Squaw Creek, a tributary of the Paluxy River, which is a tributary of the Brazos River. The site is over 30 miles southwest of the nearest portion of Fort Worth and approximately 4.5 miles north-northwest of Glen Rose, the nearest community.

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 193 fuel assemblies. Each assembly shall consist of a matrix of Zircaloy or ZIRLO™ clad fuel rods with an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing or that contain Westinghouse ZIRLO™ fuel rod cladding may be placed in non-limiting core regions.

4.2.2 Control Rod Assemblies

The reactor core shall contain 53 control rod assemblies. The control material shall be silver-indium-cadmium as approved by the NRC.

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent;

b. $k_{eff} < 1.0$ when fully flooded with unborated water which includes an allowance for uncertainties as described in Section 4.3 of the FSAR;

c. $k_{eff} \leq 0.95$ if fully flooded with water borated to 400 ppm, which includes an allowance for uncertainties as described in Section 4.3 of the FSAR;

d. A nominal 9 inch center to center distance between fuel storage locations in Region II fuel storage racks;

e. A nominal 10.65 inch by nominal 11.05 inch center to center distance between fuel assemblies placed in Region I fuel storage racks;

f. New or partially spent fuel assemblies may be allowed restricted storage in a 1 out of 4 configuration in Region II fuel storage racks (as shown in Figure 3.7.17-1, Array II-E) or unrestricted storage in Region I fuel storage racks;

g. Storage of new or spent fuel assemblies in Region II storage racks must comply with 3.7.17 Spent Fuel Assembly Storage.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent;

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 4.3 of the FSAR;

c. $k_{eff} \leq 0.98$ if moderated by aqueous foam, which includes an allowance for uncertainties as described in Section 4.3 of the FSAR; and

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

d. A nominal 21 inch center to center distance between fuel assemblies placed in the storage racks.

4.3.2 Drainage

The spent fuel storage pools are designed and shall be maintained to prevent inadvertent draining of the pool below elevation 854 ft.

4.3.3 Capacity

The spent fuel storage pools are designed and shall be maintained with a storage capacity limited to no more than 3373 fuel assemblies.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The Plant Manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

The Plant Manager or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.

5.1.2 The Shift Manager shall be responsible for the control room command function. During any absence of the Shift Manager from the control room while the unit is in MODE 1, 2, 3, or 4, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the Shift Manager from the control room while the unit is in MODE 5 or 6, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements including the plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be documented in the FSAR;

b. The Plant Manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. A specified corporate officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A non-licensed operator shall be assigned to each reactor containing fuel and an additional non-licensed operator shall be assigned if either unit is operating in MODES 1, 2, 3, or 4.

With both units shutdown or defueled, a total of three non-licensed operators for the two units is required.

5.2 Organization

5.2.2 Unit Staff (continued)

b. Shift crew composition may be one less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.e for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. -- NOTE --
A single Radiation Protection Technician and a single Chemistry Technician may fulfill the requirements for both units.

A Radiation Protection Technician and Chemistry Technician shall be on site when fuel is in the reactor. The positions may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required positions.

d. The Shift Operations Manager shall hold an SRO license.

e. An individual shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This shall be assigned to both units when either unit is in MODE 1, 2, 3, or 4. The STA position may be filled by the shift manager or an on-shift SRO providing the individuals meet the dual role qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

5.3.1 Each member of the unit staff, with the exception of licensed Senior Reactor Operators (SRO) and licensed Reactor Operators (RO), shall meet or exceed the minimum qualifications of Regulatory Guide 1.8, Revision 2, 1987.

5.3.2 Licensed Senior Reactor Operators (SRO) and licensed Reactor Operators (RO) shall meet or exceed the minimum qualifications of Regulatory Guide 1.8, Revision 3, May 2000.

5.3.3 For the purposes of 10CFR55.4, a licensed Senior Reactor Operator (SRO) and a licensed reactor operator (RO) are those individuals who, in addition to meeting the requirements of TS 5.3.2, perform the functions described in 10CFR50.54(m).

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program implementation; and

e. All programs specified in Specification 5.5.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities, and descriptions of the information that should be included in the Annual Radiological Environmental Operating, and Radioactive Effluent Release Report required by Specification 5.6.2 and Specification 5.6.3.

c. Licensee initiated changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   i. sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   ii. a determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

2. Shall become effective after the approval of the Plant Manager; and

3. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5 Programs and Manuals (continued)

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include the post accident recirculation portion of the Containment Spray System, Safety Injection System, Chemical and Volume Control System, RHR System and RCS Sampling System (Post Accident Sampling System portion only until such time as a modification eliminates the PASS penetration as a potential leakage path). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.3 Not Used

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to 10 times the concentration values in Appendix B, Table 2, Column 2, to 10 CFR 20.1001 - 20.2402;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days;

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the site boundary shall be in accordance with the following:

1. For noble gases: a dose rate of ≤ 500 mrem/yr to the total body and a dose rate of ≤ 3000 mrem/yr to the skin, and

2. For iodine-131, for iodine-133, for tritium, and for all radionuclides in particulate form with half lives greater than 8 days: a dose rate ≤ 1500 mrem/yr to any organ.

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public, beyond the site boundary, from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

k. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Radioactive Effluent Controls program surveillance frequency.

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track the FSAR, Section 3.9N, cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.6 Not used

5.5 Programs and Manuals (continued)

5.5.7 Reactor Coolant Pump Flywheel Inspection Program

This program shall provide for the inspection of each reactor coolant pump flywheel per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975. In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals.

5.5.8 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program shall include the following:

a. Testing frequencies applicable to the ASME Code for Operations and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as follows:

ASME OM Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies and to other normal and accelerated Frequencies specified as 2 years or less in the Inservice Testing Program for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME OM Code shall be construed to supersede the requirements of any TS.

5.5 Programs and Manuals (continued)

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the “as found” condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The “as-found” condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down), all anticipated transients included in the design specification, and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, “RCS Operational LEAKAGE.”

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

1. The following alternate tube plugging criteria shall be applied as an alternative to the 40% depth based criteria:

   a. For Unit 2 only, tubes with service-induced flaws located greater than 14.01 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 14.01 inches below the top of the tubesheet shall be plugged upon detection.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. For Unit 1, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria. For Unit 2, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side and that may satisfy the applicable tube plugging criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements below, the inspection scope, inspection methods and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

2. For the Unit 2 model D5 steam generators (Alloy 600 thermally treated) after the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

b. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

c. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

3. For the Unit 1 model Delta-76 steam generators (Alloy 690 thermally treated) after the first refueling outage following SG installation, inspect each SG at least every 72 effective full power months or at least every third refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, c and d below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b. During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;

c. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and

d. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.

4. For Unit 1, if crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indications shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). For Unit 2, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indications shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5 Programs and Manuals (continued)

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2 and in accordance with Regulatory Guide 1.52, Revision 2, ANSI/ASME N509-1980, ANSI/ASME N510-1980, and ASTM D3803-1989.

-----NOTE-----
ANSI/ASME N510-1980, ANSI/ASME N509-1980, and ASTM D3803-1989 shall be used in place of ANSI 510-1975, ANSI/ASME N509-1976, and ASTM D3803-1979 respectively in complying with Regulatory Guide 1.52, Revision 2.
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a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass < 1.0% for Primary Plant Ventilation System - ESF Filtration units and < 0.05% for all other units when tested in accordance with Regulatory

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate
Control Room Emergency filtration unit	8,000 CFM
Control Room Emergency pressurization unit	800 CFM
Primary Plant Ventilation System – ESF filtration unit	15,000 CFM

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 1.0% for Primary Plant Ventilation System - ESF Filtration units and < 0.05% for all other units when tested in accordance with Regulatory Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate
Control Room Emergency filtration unit	8,000 CFM
Control Room Emergency pressurization unit	800 CFM
Primary Plant Ventilation System - ESF filtration unit	15,000 CFM

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of ≤ 30°C and greater than or equal to the relative humidity specified below.

ESF Ventilation Systems	Penetration	RH
Control Room Emergency filtration unit	0.5%	70%
Control Room Emergency pressurization unit	0.5%	70%
Primary Plant Ventilation System – ESF filtration unit	2.5%	70%

d. Demonstrate at least once per 18 months for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters, and the charcoal adsorbers is less than the value specified below when tested in

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

accordance with Regulatory Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%

ESF Ventilation System	Delta P	Flowrate
Control Room Emergency filtration unit	8.0 in WG	8000 CFM
Control Room Emergency pressurization unit	9.5 in WG	800 CFM
Primary Plant Ventilation System – ESF filtration unit.	8.5 in WG	15000 CFM

e. Demonstrate at least once per 18 months that the heaters for each of the ESF systems dissipate the value specified below when tested in accordance with ANSI/ASME N510-1980.

ESF Ventilation System	Wattage
Control Room Emergency pressurization unit	10 ± 1 kW
Primary Plant Ventilation System - ESF filtration unit	100 ± 5 kW

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Gaseous Waste Processing System, the quantity of radioactivity contained in each Gas Decay Tank, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks.

The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure," Revision 0, July 1981. The liquid radwaste quantities shall be determined in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures," Revision 2, July 1981.

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Gaseous Waste Processing System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

5.5 Programs and Manuals

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

b. A surveillance program to ensure that the quantity of radioactivity contained in each Gas Decay Tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents; and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2 to 10 CFR 20.1001 - 20.2402, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

d. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.13 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. an API gravity or an absolute specific gravity within limits,

2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

3. a clear and bright appearance with proper color or a water and sediment content within limits.

b. Within 31 days following addition of the new fuel oil to the storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil, and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program.

5.5 Programs and Manuals (continued)

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. a change in the TS incorporated in the license; or

2. a change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of Specification 5.5.14b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e) and exemptions thereto.

5.5.15 Safety Function Determination Program (SFDP)

a. This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

1. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

4. Other appropriate limitations and remedial or compensatory actions.

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP) (continued)

b. A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

1. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, as modified by the following exceptions:

1. The visual examination of containment concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

2. The visual examination of the steel liner plate inside containment intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

5.5 Programs and Manuals

5.5.16 Containment Leakage Rate Testing Program (continued)

b. The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 48.3 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

d. Leakage rate acceptance criteria are:

1. Containment leakage rate acceptance criteria is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for Type A tests;

2. Air lock testing acceptance criteria are:

i. Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

ii. For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

e. The provision of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program, with the exception of the containment ventilation isolation valves.

f. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.5.17 Technical Requirements Manual (TRM)

The TRM contains selected requirements which do not meet the criteria for inclusion in the Technical Specification but are important to the operation of CPNPP. Much of the information in the TRM was relocated from the TS.

Changes to the TRM shall be made under appropriate administrative controls and reviews. Changes may be made to the TRM without prior NRC approval provided the changes do not require either a change to the TS or NRC approval pursuant to 10 CFR 50.59. TRM changes require approval of the Plant Manager.

5.5.18 Configuration Risk Management Program (CRMP)

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for

5.5 Programs and Manuals

5.5.18 Configuration Risk Management Program (CRMP) (continued)

which a risk-informed Completion Time has been granted. The program shall include the following elements:

a. Provisions for the control and implementation of a Level 1, at-power, internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Action for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Action for unplanned entry into the LCO Action.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Action.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues, and external events, qualitatively or quantitatively.

5.5.19 Battery Monitoring and Maintenance Program

This Program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," or of the battery manufacturer for the following:

a. Actions to restore battery cells with float voltage < 2.13 V, and

b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates.

5.5.20 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Filtration System (CREFS), CRE occupants can control the reactor safety under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem whole body or its equivalent to any part of the body for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

5.5 Programs and Manuals

5.5.20 Control Room Envelope Habitability Program (continued)

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

   The following are exceptions to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0:

   1. C. - Section 4.3.2 "Periodic CRH Assessment" from NEI 99-03 Revision 1 will be used as input to a site specific Self Assessment procedure.

   2. C.1.2 - No peer reviews are required to be performed.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREFS, operating at the flow rate required by the VFTP, at a Frequency of 18 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 18 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.5 Programs and Manuals

5.5.21 Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI-04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 1.

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

5.5.22 Spent Fuel Storage Rack Neutron Absorber Monitoring Program

The Region I storage cells in the CPNPP Spent Fuel Pool utilize the neutron absorbing material BORAL, which is credited in the Safety Analysis to ensure the limitations of Technical Specification 4.3.1.1 are maintained.

In order to ensure the reliability of the Neutron Poison material, a monitoring program is required to routinely confirm that the assumptions utilized in the criticality analysis remain valid and bounding. The Neutron Absorber Monitoring Program is established to monitor the integrity of neutron absorber test coupons periodically as described below.

A test coupon "tree" shall be maintained in each SFP. Each coupon tree originally contained 8 neutron absorber surveillance coupons. Detailed measurements were taken on each of these 16 coupons prior to installation, including weight, length, width, thickness at several measurement locations, and B-10 content (g/cm^2). These coupons shall be maintained in the SFP to ensure they are exposed to the same environmental conditions as the neutron absorbers installed in the Region I storage cells, until they are removed for analysis.

One test coupon from each SFP shall be periodically removed and analyzed for potential degradation, per the following schedule. The schedule is established to ensure adequate coupons are available for the planned life of the storage racks.

5.5 Programs and Manuals

5.5.22 Spent Fuel Storage Rack Neutron Absorber Monitoring Program (continued)

Year	Coupon Number	Year	Coupon Number
2013	1	2028	5
2015	2	2033	6
2018	3	2043	7
2023	4	2053	8

Further evaluation of the absorber materials, including an investigation into the degradation and potential impacts on the Criticality Safety Analysis, is required if:

- A decrease of more than 5% in B-10 content from the initial value is observed in any test coupon as determined by neutron attenuation.
- An increase in thickness at any point is greater than 25% of the initial thickness at that point.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Deleted

5.6.2 Annual Radiological Environmental Operating Report

--NOTE--
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 1 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in a format similar to the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Effluent Release Report

--NOTE--
A single submittal may be made for a multiple unit station. The submittal shall combine sections common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

The Radioactive Effluent Release Report covering the operation of the unit during the previous year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I, Section IV.B.1.

5.6.4 Deleted

5.6 Reporting Requirements (continued)

5.6.5 Core Operating Limits Report (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. Moderator temperature coefficient limits for Specification 3.1.3.

2. Shutdown Rod Insertion Limit for Specification 3.1.5.

3. Control Rod Insertion Limits for Specification 3.1.6.

4. AXIAL FLUX DIFFERENCE Limits and target band for Specification 3.2.3.

5. Heat Flux Hot Channel Factor, K(Z), W(Z), F_Q^{RTP}, and the $F_Q^{C}(Z)$ allowances for Specification 3.2.1.

6. Nuclear Enthalpy Rise Hot Channel Factor Limit and the Power Factor Multiplier for Specification 3.2.2.

7. SHUTDOWN MARGIN values in Specifications 3.1.1, 3.1.4, 3.1.5, 3.1.6 and 3.1.8.

8. Refueling Boron Concentration limits in Specification 3.9.1.

9. Overtemperature N-16 Trip Setpoint in Specification 3.3.1.

10. Reactor Coolant System pressure, temperature, and flow in Specification 3.4.1.

11. Reactor Core Safety Limit (Safety Limit 2.1.1).

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC. When an initial assumed power level of 102 percent of rated power is specified in a previously approved method, 100.6 percent of rated power may be used only when feedwater flow measurement (used as input for reactor thermal power measurement) is provided by the leading edge flowmeter (LEFM√) as described in document number 3 listed below. When feedwater flow measurements from the LEFM√ are not available, the originally approved initial power level of 102 percent of rated thermal power shall be used.

5.6 Reporting Requirements

5.6.5 Core Operating Limits Report (COLR) (continued)

Future revisions of approved analytical methods listed in this technical specification that currently assume 102 percent of rated power shall include the condition given above allowing use of 100.6 percent of rated power in safety analysis methodology when the LEFM√ is used for feedwater flow measurement.

The approved analytical methods are described in the following documents:

1. WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (W Proprietary).

2. WCAP-10216-P-A, Revision 1A, “RELAXATION OF CONSTANT AXIAL OFFSET CONTROL F_Q SURVEILLANCE TECHNICAL SPECIFICATION,” February 1994 (W Proprietary).

3. Caldon, Inc. Engineering Report-80P, “Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power level Using the LEFM√ System,” Revision 0, March 1997 and Caldon Engineering Report – 160P, “Supplement to Topical Report ER-80P; Basis for a Power Uprate With the LEFM√tm System,” Revision 0, May 2000.

4. WCAP-10444-P-A, “Reference Core Report VANTAGE 5 Fuel Assembly,” September 1985.

5. WCAP-15025-P-A, “Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles for Modified LPD Mixing Vane Grids,” April 1999.

6. WCAP-10360-P-A, “Westinghouse Fuel Assembly Reconstitution Evaluation Methodology,” July, 1993.

7. WCAP-11397-P-A, “Revised Thermal Design Procedure,” April 1989.

8. WCAP-8745-P-A, “Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions,” September 1986.

9. WCAP-14565-P-A, “VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis,” October 1999.

10. WCAP-14882-P-A, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses,” April 1999.

5.6 Reporting Requirements

5.6.5 Core Operating Limits Report (COLR) (continued)

11. WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," August 1985.

12. WCAP-10054-P-A, Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," July 1997.

13. WCAP-10079-P-A, "NOTRUMP, A Nodal Transient Small Break and General Network Code," August 1985.

14. WCAP-16009-P-A, "Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," January 2005.

15. WCAP-12472-P-A, "BEACON Core Monitoring and Operations Support System," August 1994.

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing, and PORV lift settings as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

1. Specification 3.4.3, "RCS Pressure and Temperature (P/T) Limits," and

2. Specification 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

5.6 Reporting Requirements

5.6.6 <u>Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)</u> (continued)

1. WCAP-14040-NP-A; “Methodology used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves.”

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.6.7 <u>Not used</u>

5.6.8 <u>PAM Report</u>

When a report is required by the required actions of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.9 <u>Unit 1 Model D76 and Unit 2 Model D5 Steam Generator Tube Inspection Report</u>

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each degradation mechanism,

f. The number and precentage of tubes plugged to date, and the effective plugging percentage in each steam generator,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing,

h. For Unit 2, the primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to

5.6 Reporting Requirements

5.6.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator Tube Inspection Report (continued)

secondary leakage should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

i. For Unit 2, the calculated accident induced leakage rate from the portion of the tubes below 14.01 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 3.16 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

j. For Unit 2, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

5.7.1 High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation:

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area; or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously, transmits dose rate information and cumulative dose to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure with the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

i. Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

5.7 High Radiation Area

5.7.1 High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

ii. Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation:

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the [shift manager], or his or her designee.

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation: (continued)

1. A radiation monitoring device that continuously integrates the radiation rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

   i. Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

   ii. Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the Low As is Reasonably Achievable principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

e. Except for individuals qualified in radiation protection procedures or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

f. Such individual areas that are within a larger area , such as PWR containment, where no enclosure exists for the purpose of locking and where

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation: (continued)

no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

TS EFFECTIVE PAGE LISTING

Amendment Record:

Amendment No. 64	July 27, 1999
Amendment No. 65	July 27, 1999
Amendment No. 66	August 31, 1999
Amendment No. 67	September 29, 1999
Amendment No. 68	September 29, 1999
Amendment No. 69	September 30, 1999
Amendment No. 70	September 30, 1999
Amendment No. 71	September 30, 1999
Amendment No. 72	October 7, 1999
Amendment No. 73	December 30, 1999
Amendment No. 74	December 31, 1999
Amendment No. 75	April 23, 2000
Amendment No. 76	April 23, 2000
Amendment No. 77	May 26, 2000
Amendment No. 78	June 29, 2000
Amendment No. 79	September 19, 2000
Amendment No. 80	October 12, 2000
Amendment No. 81	December 8, 2000
Amendment No. 82	Security Plan
Amendment No. 83	March 19, 2001
Amendment No. 84	April 18, 2001
Amendment No. 85	May 18, 2001
Amendment No. 86	July 17, 2001
Amendment No. 87	January 3, 2002
Amendment No. 88	November 1, 2001
Amendment No. 89	October 16, 2001
Amendment No. 90	Operating License
Amendment No. 91	March 13, 2003
Amendment No. 92	March 25, 2002
Amendment No. 93	March 25, 2002
Amendment No. 94	Operating License
Amendment No. 95	April 8, 2002
Amendment No. 96	July 24, 2002
Amendment No. 97	August 15, 2002
Amendment No. 98	October 8, 2002
Amendment No. 99	September 24, 2002
Amendment No. 100	September 24, 2002
Amendment No. 101	October 8, 2002
Amendment No. 102	February 28, 2003
Amendment No. 103	January 15, 2004
Amendment No. 104	Operating License
Amendment No. 105	August 21, 2003
Amendment No. 106	September 18, 2003
Amendment No. 107	TS Bases Revision 31 & FSAR
Amendment No. 108	October 2, 2003
Amendment No. 109	March 23, 2004

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Amendment Record:

Amendment No. 110	March 23, 2004
Amendment No. 111	March 23, 2004
Amendment No. 112	April 7, 2004
Amendment No. 113	August 26, 2004
Amendment No. 114	April 7, 2005
Amendment No. 115	April 7, 2005
Amendment No. 116	June 2, 2005
Amendment No. 117	August 4, 2005
Amendment No. 118	August 4, 2005
Amendment No. 119	August 4, 2005
Amendment No. 120	September 22, 2005
Amendment No. 121	December 8, 2005
Amendment No. 122	November 3, 2005
Amendment No. 123	October 11, 2005 (Unit 1)
Amendment No. 123	March 30, 2006 (Unit 2)
Amendment No. 124	April 24, 2006
Amendment No. 125	April 17, 2006
Amendment No. 126	June 15, 2006
Amendment No. 127	November 16, 2006
Amendment No. 128	October 4, 2006
Amendment No. 129	October 17, 2006
Amendment No. 130	Operating License & FSAR
Amendment No. 131	March 30, 2007
Amendment No. 132	March 30, 2007
Amendment No. 133	June 21, 2007
Amendment No. 134	June 21, 2007
Amendment No. 135	March 30, 2007
Amendment No. 136	April 11, 2007
Amendment No. 137	July 24, 2007
Amendment No. 138	July 24, 2007
Amendment No. 139	Operating License
Amendment No. 140	February 28, 2008
Amendment No. 141	February 28, 2008
Amendment No. 142	February 28, 2008
Amendment No. 143	Operating License
Amendment No. 144	April 4, 2008
Amendment No. 145	April 4, 2008
Amendment No. 146	September 11, 2008
Amendment No. 147	November 13, 2008
Amendment No. 148	October 1, 2009
Amendment No. 149	October 15, 2009
Amendment No. 150	May 18, 2010
Amendment No. 151	May 18, 2010
Amendment No. 152	December 16, 2010
Amendment No. 153	December 16, 2010
Amendment No. 154	April 12, 2011

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Amendment Record:

Amendment No. 155	OL Change Only
Amendment No. 156	September 11, 2012
Amendment No. 157	September 11, 2012
Amendment No. 158	October 23, 2012
Amendment No. 159	August 27, 2013
Amendment No. 160	October 10, 2013
Amendment No. 161	March 26, 2014
Amendment No. 162	August 11, 2014
Amendment No. 163	OL Change Only
Amendment No. 164	April 2, 2015
Amendment No. 165	April 14, 2016

(continued)

(continued)

(continued)

ATTACHMENT 7
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RCS PRESSURE/TEMPERATURE VERIFICATION

Time		0900	0930	1000				
PRZR PRESS	1-PI-455B	2085	1790	855				
Tsat from Steam Table (2)	→							
PRZR LVL	1-LI-459B	49%	33%	25%				
NEUT FLUX SR	1-NI-50A-3	475	415	335				
RCS LOOP (4)	CL1	557	540	440				
1 & 2 TEMP	CL2	556	540	440				
1-TR-410F	HL1	557	545	445				
	HL2	557	545	440				
Calculated Subcooling ˚F	→							
SG 1 PRESS (2)	1-PI-514B	1092	1030	425				
Tsat from Steam Table (2)	→							
SG 1 LVL (WR) (1)	1-LI-501A	76	77	79				
SG 2 LVL (WR) (1)	1-LI-502A	77	77	78				
SG 2 PRESS (2)	1-PI-524B	1092	1030	435				
Tsat from Steam Table (2)	→							
RCS LOOP (4)	CL3	556	550	440				
3 & 4 TEMP	CL4	556	550	445				
1-TR-430F	HL3	557	552	440				
	HL4	557	550	445				
SG 3 PRESS (2)	1-PI-534B	1092	1030	450				
Tsat from Steam Table (2)	→							
SG 3 LVL (WR) (1)	1-LI-503A	77	76	78				
SG 4 LVL (WR) (1)	1-LI-504A	76	75	77				
SG 4 PRESS (2)	1-PI-544B	1090	1040	415				
Tsat from ST	→							
COOLDOWN RATE	(3) →							

(1) SG Level (WR) Cold Cal of approximately 74% corresponds to an AFW Pump Low Level Auto Start signal.

(2) Steam pressure converted to Tsat/Tcold is the best indication of temperature and temperature changes.

(3) Cooldown rate should be calculated based on most conservative SG Press reading. Calculate cooldown using Tsat values and steam tables, with SG Press reading that has dropped the largest amount from last reading.

(4) RCS indicated temperature response will be slow due to slow response time of strap on RTDs.

NOTE: When completed, this attachment shall be dispositioned by attaching it to the SMART Form generated as a result of this abnormal condition.

Initial Conditions: **Given the following conditions:**

- **ABN-905A, Loss of Control Room Habitability, Attachment 7, RCS Pressure / Temperature Verification, is in progress.**
- **Reactor Coolant System cooldown is in progress.**

Initiating Cue: **The Shift Manager directs you to PERFORM the following:**

- **UTILIZING the data provided, CALCULATE the identified parameters (shown with arrows) on Attachment 7, RCS Pressure/Temperature Verification, per ABN-905A, Loss of Control Room Habitability.**
- **When complete, IDENTIFY all Technical Specification CONDITIONs, REQUIRED ACTIONs, and COMPLETION TIMEs if any.**

Technical Specification LCO 3.4.3, RCS Pressure and Temperature

Limits is applicable:

CONDITION A: Requirements of the LCO not met in MODE 1, 2, 3, or 4.

REQUIRED ACTION AND COMPLETION TIME:

A.1 – Restore parameter(s) to within limits in 30 minutes

-AND-

A.2 – Determine RCS is acceptable for continued operation

Within 72 hours

CPNPP ABNORMAL CONDITIONS PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. ABN-905A
LOSS OF CONTROL ROOM HABITABILITY	REVISION NO. 9	PAGE 46 OF 74

ATTACHMENT 7
PAGE 1 OF 2

RCS PRESSURE/TEMPERATURE VERIFICATION

Time		0900	0930	1000				
PRZR PRESS	1-PI-455B	2085	1790	855				
Tsat from Steam Table (2)	→	643	621	528				
PRZR LVL	1-LI-459B	49%	33%	25%				
NEUT FLUX SR	1-NI-50A-3	475	415	335				
RCS LOOP (4)	CL1	557	540	440				
1 & 2 TEMP	CL2	556	540	440				
1-TR-410F	HL1	557	545	445				
	HL2	557	545	440				
Calculated Subcooling °F	→	86	73	88				
SG 1 PRESS (2)	1-PI-514B	1092	1030	425				
Tsat from Steam Table (2)	→	557	550	456				
SG 1 LVL (WR) (1)	1-LI-501A	76	77	79				
SG 2 LVL (WR) (1)	1-LI-502A	77	77	78				
SG 2 PRESS (2)	1-PI-524B	1092	1030	435				
Tsat from Steam Table (2)	→	557	550	456				
RCS LOOP (4)	CL3	556	550	440				
3 & 4 TEMP	CL4	556	550	445				
1-TR-430F	HL3	557	552	440				
	HL4	557	550	445				
SG 3 PRESS (2)	1-PI-534B	1092	1030	450				
Tsat from Steam Table (2)	→	557	550	459				
SG 3 LVL (WR) (1)	1-LI-503A	77	76	78				
SG 4 LVL (WR) (1)	1-LI-504A	76	75	77				
SG 4 PRESS (2)	1-PI-544B	1090	1040	415				
Tsat from ST	→	557	551	451				
COOLDOWN RATE	(3) →	N/A	14	106				

(1) SG Level (WR) Cold Cal of approximately 74% corresponds to an AFW Pump Low Level Auto Start signal.

(2) Steam pressure converted to Tsat/Tcold is the best indication of temperature and temperature changes.

(3) Cooldown rate should be calculated based on most conservative SG Press reading. Calculate cooldown using Tsat values and steam tables, with SG Press reading that has dropped the largest amount from last reading.

(4) RCS indicated temperature response will be slow due to slow response time of strap on RTDs.

NOTE: When completed, this attachment shall be dispositioned by attaching it to the SMART Form generated as a result of this abnormal condition.

* All temperatures are ± 1°F.

Facility: CPNPP JPM # NRC SA2 Task # SO1004 K/A # 2.1.4 3.3 / 3.8

Title: Determine Licensed Operator License Status

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- The plant was at 100% power, when the RO had a medical emergency and will not be able to work his next scheduled shift. The Operations Shift Attendant has contacted four off shift individuals to replace the RO on the following day.
- Today is April 6, 2017.
- Four Staff Reactor Operators are available to be assigned as the Unit 1, RO for the April 6^{th} day shift.
- Given the first quarter shifts were worked as recorded in the Unit and Station Logs on the Handout.
- Unit 1 had unit trip on 3/12 and returned to power on 3/14.
- Unit 2 maintained 100% power during the first quarter.

Initiating Cue: The Shift Manager directs you to PERFORM the following:

- DETERMINE which Reactor Operators are current on maintaining proficiency of an Active License. (Circle Correct Status)
  - RO #1 Active Inactive
  - RO #2 Active Inactive
  - RO #3 Active Inactive
  - RO #4 Active Inactive
- DETERMINE which Reactor Operator(s) satisfy the requirements to fill the Unit 1, RO position for the oncoming shift.
  - RO(s) ________________ can be assigned as the Unit 1 RO.

Task Standard: DETERMINED license status of each RO and DETERMINED the ROs qualified to stand the watch as the Unit 1, RO for the April 6^{th} day shift.

Ref. Materials: ODA-315, Licensed Operator Maintenance Tracking, Rev. 7.
ODA-315-1, Active License Status Form, Rev. 8.

Validation Time: 10 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ______________

CLASSROOM SETUP

EXAMINER:

PROVIDE the examinee with a copy of:

- **ODA-315, Licensed Operator Maintenance Tracking (Procedure 1)**
- **OWI-107, Operations Department Briefing and Turnover Instructions (Procedure 2)**
- **ODA-315-1, Active License Status Form (Form)**
- **Work History Log Handout (Handout)**

√ - Check Mark Denotes Critical Step

START TIME:	

Perform Step: 1√	DETERMINE which Reactor Operators are current on maintaining proficiency of an Active License. (Circle Correct Status)
Standard:	DETERMINED RO #1 has only stood four 12-hour watches which qualify as RO watches. Watches as CPC RO do not count as a licensed proficiency watch. CIRCLED Inactive for RO #1.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2√	DETERMINE which Reactor Operators are current on maintaining proficiency of an Active License. (Circle Correct Status)
Standard:	DETERMINED RO #2 has reactivated during the previous quarter and although he has only stood four watches, he is still considered active. CIRCLED Active for RO #2.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3√	DETERMINE which Reactor Operators are current on maintaining proficiency of an Active License. (Circle Correct Status)
Standard:	DETERMINED RO #3 has just received his license and is active as soon as the licensed is received, and is therefore still active. CIRCLED Active for RO #3.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4√	DETERMINE which Reactor Operators are current on maintaining proficiency of an Active License. (Circle Correct Status)
Standard:	DETERMINED RO #4 has worked a total of 4 12 shifts that would count towards maintaining an active status. The watch of 12/31/16 does not count toward this quarter's proficiency. The watch on 2/18/17 does not count because the operator would have to have an OWI-107 relief for two hours. CIRCLED Inactive for RO #4.
Comment:	**SAT ☐ UNSAT ☐**
Perform Step: 4√	DETERMINE which Reactor Operator(s) satisfy the requirements to fill the Unit 1, RO position for the April 6th day shift.
Standard:	DETERMINED ROs 2 and 3 can be assigned as the RO.
<u>Terminating Cue:</u>	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **The plant was at 100% power, when the RO had a medical emergency and will not be able to work his next scheduled shift. The Operations Shift Attendant has contacted four off shift individuals to replace the RO on the following day.**
- **Today is April 6, 2017.**
- **Four Staff Reactor Operators are available to be assigned as the Unit 1, RO for the April 6th day shift.**
- **Given the first quarter shifts were worked as recorded in the Unit and Station Logs on the Handout.**
- **Unit 1 had unit trip on 3/12 and returned to power on 3/14.**
- **Unit 2 maintained 100% power during the first quarter.**

Initiating Cue: **The Shift Manager directs you to PERFORM the following:**

- **DETERMINE which Reactor Operators are current on maintaining proficiency of an Active License. (Circle Correct Status)**

  - **RO #1** **Active** **Inactive**
  - **RO #2** **Active** **Inactive**
  - **RO #3** **Active** **Inactive**
  - **RO #4** **Active** **Inactive**

- **DETERMINE which Reactor Operator(s) satisfy the requirements to fill the Unit 1, RO position for the oncoming shift.**

  - **RO(s) ______________ can be assigned as the Unit 1 RO.**

COMANCHE PEAK NUCLEAR POWER PLANT

OPERATIONS DEPARTMENT ADMINISTRATION MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____________/_______ LATEST PCN/EFFECTIVE DATE __PCN 1__/__02/25/16 1200__

LEVEL OF USE:
INFORMATION USE

QUALITY RELATED

LICENSED OPERATOR MAINTENANCE TRACKING

PROCEDURE NO. ODA-315

REVISION NO. 7

SORC MEETING NO.: __14-002__ DATE: __1/23/14__

EFFECTIVE DATE: __1/28/2014 1200__

PREPARED BY (Print): __Bettina Withers__ Ext: __5336__

TECHNICAL REVIEW BY (Print): __Les Meller__ Ext: __6009__
APPROVED BY: __B.St.Louis for M.R. Smith__ Date: __1/23/14__
DIRECTOR, OPERATIONS

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1.0 PURPOSE

This procedure describes the administrative and documentation requirements necessary to maintain a license as Active, including the reactivation of an Inactive License.

2.0 APPLICABILITY

This procedure is applicable to all CPSES Licensed Operators.

3.0 REFERENCES

3.1 Performance References

- ODA-102, Conduct of Operations
- ODA-104, Operations Department Document Control
- ODA-106, Review of Documents and Operational Experience Feedback
- ODA-308, LCO Tracking Program
- OWI-107, Operations Department Turnover and Briefing Instructions
- OWI-207, Operations Department Activity File
- RFO-101, Refueling Organization
- STA-302, Station Records
- TRA-203, Replacement License Training
- TRA-204, License Operator Requalification Training Program
- Operations Guideline No. 15, Operations Department Miscellaneous Recurrent Training and Qualifications
- Operations Guideline No. 16, Personnel Related Policies
- FSAR Table 13.1-2

3.2 Development References

- 10CFR50.54, Title 10, “Code of Federal Regulations”, Part 50.54
- 10CFR55.53, Title 10, “Code of Federal Regulations”, Part 55.53
- ODA-106, Review of Documents and Operational Experience Feedback
- NUREG-1262, Answers to Questions at Public Meetings Regarding Implementation of Title 10 Code of Federal Regulations, Part 55 on Operator Licenses - June 1987
- CPSES Technical Specifications
- SOER 96-1, Control Room Supervision, Operational Decision Making and Team Work

4.0 DEFINITIONS/ACRONYMS

4.1 Active License - The status of a license which permits a Reactor Operator (RO) or Senior Reactor Operator (SRO) to manipulate the controls of the reactor and permit a Senior Reactor Operator to direct the manipulation of the controls of the reactor.

4.2 Actively performing the functions of an operator or senior operator - An individual who carries out and is responsible for a position on a shift crew which is required to hold an Active RO or SRO license.

4.3 Balance of Plant Operator (BOP) - Any individual who possesses an operator's license pursuant to 10CFR55, Operator's Licenses, and who serves as an extra operator on shift normally assisting with the secondary plant.

4.4 Comprehensive Plant Tour - A complete tour of the operating areas of the plant to include the Auxiliary Building, Electrical Control Building, Service Water Intake Structure, Circ Water Intake Structure, Safeguards Buildings for each Unit and Turbine Buildings for each Unit. The Comprehensive Plant Tour is to be conducted with an Active RO or SRO if reactivating as an RO, or an Active SRO if reactivating as an SRO.

4.5 Core Alterations - Core alterations shall be the movement or manipulation of applicable components within the reactor pressure vessel with the vessel head removed and fuel in the vessel per RFO-102.

4.6 Inactive License - The status of a license maintained by an individual who does not meet or exceed the requirements for an Active license.

4.7 Miscellaneous Recurrent Training and Qualifications - The various elements related to keeping a licensee's various qualifications and administrative or regulatory obligations current. These elements include medical physicals, computer based training, practical training, or any of the other constituents of initial or recurrent training or conditions described in Operations Guideline Nos. 15 and 16.

4.8 Reactor Operator (RO) - Any individual who possesses an operator's license pursuant to 10CFR55, Operators' Licenses.

4.9 Senior Reactor Operator (SRO) - Any individual who possesses a senior operator's license pursuant to 10CFR55, Operators' Licenses.

4.10 Steam Generator Operator (SGO) - Any licensed active RO or licensed SRO who is dedicated to the manipulation of the Steam Generator Water Level controls via the Main Feedwater or AFW system during a reactor startup (mode 3 to mode 1) or reactor shutdown (mode 1 to mode 3).

5.0 RESPONSIBILITIES

5.1 Shift Operations Manager - Responsible for verifying that current, active licensed operators are manipulating or directing the manipulation of the controls.

5.2 Operations Support Supervisor - Maintains this procedure current.

5.3 Shift Manager (SM) - Responsible for assuring minimum shift staffing is present in accordance with CPSES Technical Specifications and the FSAR.

5.4 Operator - Responsible for informing immediate supervision if the minimum criteria as specified in TRA-203, TRA-204 or other Miscellaneous Recurrent Training and Qualifications requirements, as defined above, are not met and is, therefore, unable to properly execute the assigned licensed duties.

6.0 INSTRUCTIONS

6.1 General

6.1.1 Normally the Shift Manager, Unit Supervisor, Reactor Operator and Balance of Plant Operators will be required to be Active in all MODES of operation.

During Core Alterations, an additional SRO may receive credit for Active Licensed time as a Fuel Handling SRO.

During Plant Startup or Plant Shutdown (MODES 1, 2 and 3), an additional RO may receive credit for Active Licensed time for manipulating the controls of the Main Feedwater or AFW system as a Steam Generator Operator (SGO).

6.1.2 Newly licensed ROs and SROs receive their licenses from the NRC in an Active status and are exempt from meeting the Active Licensed watchstanding requirements of this procedure during the first calendar quarter in which they hold their license. The individual should maintain all other miscellaneous training requirements current during this time. To remain Active, they will need to meet the watchstanding requirements of this procedure beginning in the second calendar quarter after receiving their license.

6.1.3 Licensed Operators who are removed from licensed duties via the provisions of TRA-203 or TRA-204 would be required to complete specified remedial and accelerated training in addition to meeting the requirements of Section 6.2 or 6.3 prior to returning to Active Licensed duties.

6.1.4 In order to effectively be considered a part of the minimum shift complement, the Active License Operator must maintain certain administrative Miscellaneous Recurrent Training and Qualifications, which are aside from the processes described in TRA-203 and TRA-204. Operations Guideline Nos. 15 and 16, “Operations Department Miscellaneous Recurrent Training and Qualifications”, and “Personnel Related Policies”, respectively, describe these elements. ODA-315-1 and ODA-315-2 contain provisions for documenting the Operator’s awareness of and concurrence to the currentness of these elements.

6.1.5 Reactor Operators participating in a Senior Reactor Operator upgrade training program are considered Inactive Licensed from the time they become delinquent in the requalification program. Participants are considered Inactive Licensed until they successfully complete the training program and receive an SRO license or complete a remedial training program in accordance with TRA-204 to satisfy any missed requalification assignments.

6.2 Maintaining an Active License Status

NOTE: Completion of the requirements of this section are documented on ODA-315-1, “Active License Status Form”.

6.2.1 The requirements by which the Operator maintains an Active License are as follows:

- The Operator shall maintain “Current” license status in accordance with TRA-203 and TRA-204, and
- The Operator shall complete at least five (5) 12-hour shifts from shift turnover to shift turnover each calendar quarter. The Operator must complete each watch in a position that requires an Active License commensurate with the license held by the individual. Positions which require an Active License are described in Attachment 8.A.

EXAMPLES

An Operator that completes five (5) 12-hour shifts from Beginning of Shift turnover to End of Shift turnover per OWI-107 in the same calender quarter has satisfied the minimum requirements to maintain an Active License status.

IF an Operator performs a turnover to another Operator per OWI-107 during a 12-hour shift (anytime between Beginning of Shift turnover to End of Shift turnover), THEN the shift CAN NOT be counted towards one (1) of the five (5) 12-hour shifts for that calender quarter.

IF an Operator performs a Short Term Relief per OWI-107 during a 12-hour shift (anytime between Beginning of Shift turnover to End of Shift turnover), THEN the shift CAN be counted towards one (1) of the five (5) 12-hour shifts for that calender quarter.

IF an Operator begins a shift at 1800 on the final day of the calender quarter, THEN the shift CAN NOT be counted towards one (1) of the five (5) 12-hour shifts for the current quarter OR towards the next quarter since the shift is split between the current and new quarter.

6.2.2 Documentation for the maintenance requirements of this section is as follows:

- The identity of each person holding a position, which requires an Active License, should be documented in the Unit Log or Station Log per ODA-104. Documentation is normally accomplished through completion of the information (position manned) in the Narrative Logs.

<u>NOTE</u>: The Licensed Operator completes Sections I, II, and III of ODA-315-1, "Active License Status Form". Licensed Operators who are Inactive Licensed are not required to complete the form.

- When the required number of hours, per step 6.2.1, are documented, the licensed Operator should sign his/her name in Section II of ODA-315-1.

<u>NOTE</u>: The Miscellaneous Recurrent Training and Qualifications necessary for specific watch-stations are described in Operations Guideline No. 15. Additionally, Operations Guideline No. 16 describes the expectations relative to being respirator ready.

- The licensed Operator signs and dates Section III of ODA-315-1 to indicate that he/she is current in Miscellaneous Recurrent Training and Qualifications and is aware of near-term expiration dates. The signature also indicates possession of a pair of respirator glasses, if so required. Upon completion of this section, the form is forwarded to the appropriate level of Operations Management (SM/SOM).

6.2.3 The appropriate individual (SM/SOM) signs and dates Section IV certifying that requirements to maintain an Active License have been satisfied based on information supplied. The license remains Active until the end of the quarter following the watches performed per Section 6.2.1. The completed form is forwarded to the Shift Operations Department Staff.

<u>EXAMPLE</u>:

<u>IF</u> the shifts/watches (five 12-hour shifts per Section 6.2.1) are completed in the first quarter of a year, <u>THEN</u> Active License status is satisfied through the second quarter of the year. To remain in an "Active License status" for the third quarter of the year, the shifts/watches requirements of Section 6.2.1 shall be completed during the second quarter.

6.3 Reactivating an Inactive License

NOTE: Completion of the requirements of this section are documented on ODA-315-2, "Return to Active License Status Form", which is forwarded to the Shift Operations Manager for formal authorization and signature *prior* to the individual being considered Activated.

6.3.1 To activate an SRO license, the shift function is to be with a Shift Manager or Unit Supervisor. To activate an RO license, the shift function is to be with a Reactor Operator or Balance of Plant Operator. The specific requirements are as follows:

- The Operator shall maintain "Current" license status in accordance with TRA-203 and TRA-204, and

NOTE: Only one Operator should be under the direction of an Active Licensed Operator at a time

- The Operator shall perform at least 40 hours of shift functions under the direction of an Active Licensed Operator commensurate with the licensed position for which he/she is licensed. These 40 hours may be accumulated at any incremental duration and should be logged in the Unit or Station Log, as applicable; however, the minimum duration should be approximately 4 hours. The 40 hours shall be acquired within the same calendar quarter, and

- The 40 hours of shift function shall include at least one complete off-going AND one complete on-coming turnover, and

NOTE: The plant tour and required reading aspects of reactivation are to be accomplished during the 40 hours of shift function.

- The Operator shall perform a Comprehensive Plant Tour with an Active RO or SRO (if reactivating as an RO) or Active SRO (if reactivating as an SRO), and

6.3.1 • The Operator shall review all required shift turnover procedures, logs and processes relative to the position (RO or SRO) for which he/she is reactivating under the direction of an Active Licensed Operator. This review includes the following procedures and processes:

- ODA-102, Conduct of Operations
- ODA-104, Operations Department Document Control
- ODA-106, Review of Documents and Operational Experience Feedback
- ODA-308, LCO Tracking Program
- OWI-107, Operations Department Turnover and Briefing Instructions
- Unit Difference Log
- LCOAR Logs (including SISL)
- Lessons Learned (previous 3-months)
- Temporary Modifications (installed)
- Operations Guidelines (specified by S.O.M.)
- Operations Standing Orders
- Operations Shift Order (including Chemistry & RadWaste)
- OFI's, Burdens and WAL *
- Operational Decision Making Instructions (ODMI's) in effect *

(* These items are links on the Ops Web page under Turnover items.)

• For SROs who have been issued a "Fuel Handling Only" license, they may activate their license by performing one shift of shift functions meeting the requirements of RFO-101 while being supervised by an Active Licensed SRO. For SROs who are fully licensed, they must meet the full requirements of this section before activating their license for Fuel Handling Activities.

6.3.2 Documentation for the reactivation requirements of step 6.3.1 is as follows:

• Time spent in each shift function held by the Operator, which requires an Active License, should be documented in the Unit Log or Station Log per ODA-104. Documentation may be accomplished through completion of the information (position manned) in the Narrative Logs.

NOTE:	The Inactive Licensed Operator completes Sections I, II, III, IV and V of ODA-315-2, "Return to Active License Status Form". This form is the official record of reactivation.

• Upon completion of at least 40 hours of shift functions per step 6.3.1, the Inactive Licensed Operator completes the Tabulation of Hours section of ODA-315-2 and signs and dates at the bottom of Section II.

6.3.2
- Upon completion of a review of Miscellaneous Recurrent Training and Qualifications, the Inactive Licensed Operator signs and dates at the bottom of Section III. The intent of this action is to ensure the individual's miscellaneous training activities have not expired, or if any has, to attain current status prior to becoming Active. The Miscellaneous Recurrent Training and Qualifications necessary for specific watch-stations are described in Operations Guideline No. 15. Additionally, Operations Guideline No. 16 describes the expectations relative to being respirator ready - license holders are expected to be respirator qualified in support of shift manning. The signature also indicates possession of a pair of respirator glasses, if so required.
- Upon completion of a Comprehensive Plant Tour per step 6.3.1, the Inactive Licensed Operator and Active Licensed Operator signs and dates at the bottom of Section IV.
- Upon completion of a review of all required procedures, logs and processes per step 6.3.1, the Inactive Licensed Operator signs and dates at the bottom of Section V.
- The Inactive Licensed Operator participates in an oral discussion/review with Operations Management (SOM or SM or designee) covering department policies such as those contained in Operations Guidelines. Upon completion, the individual conducting the review signs and dates Section VI.
- After completion of Sections I through VI, the Inactive Licensed Operator forwards the "Return to Active License Status Form" to the Shift Operations Manager.

NOTE: A Licensed Operator who activates a license by the method described in this section implements the Active License maintenance requirements of Section 6.2 beginning in the next calendar quarter following the activation.

6.3.3 The SOM will sign and date Section VII authorizing the Licensed Operator be returned to Active License Status. The license status will change on the date Section VII is signed.

6.4 Inactive SRO Annual Review

6.4.1 Inactive Licensed SROs are likely candidates for the function of Duty Manager. Therefore, these individuals should maintain familiarity with the Operations Guidelines and Standing Orders to assure they are "current" on Shift Operations Department's day-to-day management philosophies and expectations. This review should be accomplished on an annual basis and controlled in accordance with OWI-207.

- Approximately once per year, each Inactive Licensed SRO is expected to complete ODA-315-3, "Inactive Licensed SRO Annual Review Form", and upon completion, forward the form to the SOM.

6.5 Removing Administrative License Restriction

NOTE:	Completion of the requirements of this section are documented on ODA-315-4, "Release of Administrative License Restriction Form", which is approved by the Shift Operations Manager.

6.5.1 In section II of the "Release of Administrative License Restriction Form", the Licensed Operator verifies that proficiency of watchstanding duties is maintained per section 6.2, "Maintaining an Active License Status".

- IF the required number of watches cannot be completed within the calendar quarter, THEN the operator will need to compete Section 6.3, "Reactivitating an Inactive License".

6.5.2 Upon completion of a review of Miscellaneous Recurrent Training and Qualifications, the Licensed Operator signs and dates at the bottom of Section III. The intent of this action is to ensure the individual's miscellaneous training activities have not expired, or if any has, to attain current status prior to removal of Administrative Restriction. The Miscellaneous Recurrent Training and Qualifications necessary for specific watch-stations are described in Operations Guideline No. 15. Additionally, Operations Guideline No. 16 describes the expectations relative to being respirator ready - license holders are expected to be respirator qualified in support of shift manning. The signature also indicates possession of a pair of respirator glasses, if so required.

6.5.3 In Section IV of the "Release of Administrative License Restriction Form", document the completion of requirements for the removal of the Administrative License Restriction.

6.5.4 The SOM will sign and date Section V authorizing removal of the Administrative License Restriction. The license status will change on the date Section V is signed.

7.0 FIGURES

None

8.0 ATTACHMENTS/FORMS

8.1 Attachments

8.1.1 Attachment 8.A - Positions Requiring an Active License

8.2 Forms

8.2.1 ODA-315-1, “Active License Status Form”

8.2.2 ODA-315-2, “Return to Active License Status Form”

8.2.3 ODA-315-3, “Inactive Licensed SRO Annual Review Form”

8.2.4 ODA-315-4, “Release of Administrative License Restriction Form”

9.0 RECORDS

When completed, the following forms, reports, or other documents generated in response to this procedure shall be dispositioned in accordance with STA-302, “Station Records”.

9.1 ODA-315-2, “Return to Active License Status Form”

ATTACHMENT 8.A
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POSITIONS REQUIRING AN ACTIVE LICENSE

The following list gives as a minimum those positions which are required to hold an Active License as specified in this procedure:

1. Shift Manager (SM)
2. Unit Supervisor (US)
3. Reactor Operator (RO)
4. Balance of Plant Operator (BOP)
5. Fuel Handling Supervisor (FHS)
6. Steam Generator Operator (SGO)

COMANCHE PEAK NUCLEAR POWER PLANT

OPERATIONS DEPARTMENT WORK INSTRUCTIONS

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____________/_______ LATEST PCN/EFFECTIVE DATE PCN 6 / 8/19/15 1200 |

LEVEL OF USE:
INFORMATION USE

OPERATIONS DEPARTMENT TURNOVER AND BRIEFING INSTRUCTIONS

PROCEDURE NO. OWI-107

REVISION NO. 8

EFFECTIVE DATE: 11/10/11 1200

PREPARED BY (Print): Bart Smith Ext: 5336

TECHNICAL REVIEW BY (Print): Juannelle Miller Ext: 5835

APPROVED BY: A. Hall for Steven Sewell Date: 11/7/11

DIRECTOR, OPERATIONS

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[C] 1.0 PURPOSE [01084, 09037]

This work instruction describes the process used for shift turnover, pre-job briefs and post-job critiques. Relief Checklists for the various watch-stations are described in Section 8.0.

2.0 APPLICABILITY

This work instruction applies to Shift Managers, Unit Supervisors, Shift Technical Advisors, Field Support Supervisors, Reactor Operators, Nuclear Equipment Operators, and Radwaste Operators. These instructions are specifically written for Shift Operations, but may be used by other departments as guidance for similar processes.

3.0 REFERENCES

3.1 ODA-102, "Conduct of Operations"

3.2 ODA-401, "Control of Annunciators, Instruments and Protective Relays"

3.3 STA-122, “Infrequently Performed Tests or Evolutions”

3.4 STI-429.04, “Pre Job and Post Job Briefs and Take Two” |

3.5 FSAR Section 13.5.1.3

3.6 DESKTOP INSTRUCTION NO. 007. “Operations Work Control Processes”

3.7 DESKTOP INSTRUCTION NO. 016, “SOMS Narrative Logs”

3.8 SOER 87-01, "Core Damaging Accident Following an Improperly Conducted Test"

3.9 Commitments:

- 01084, Procedures & Instructions for Shift Operational Activities
- 05240, NEO Relief of Personnel Checklist will be Developed
- 08294, Operator Should Not Assume At-The-Controls for Two Units at the Same Time
- 08295, Responsibilities of the Relief Operator
- 09037, Shift and Relief Turnover & Checklist
- 14851, STA Responsibilities Including Shift Activities
- 23316, Core Damaging Accident (SOER 87-01, Rec. 2)
- 23458, Manpower Planning for Work At the End of Shift
- 23463, RO and NEO to Brief Personnel Prior to Work
- 23474, Oncoming Crew Briefing by SRO
- 23486, Shift Log Information Requirements
- 23627, Training of Operator on PCNs
- 26022, Conduct of Infrequently Performed Tests or Evolutions (SOER 91-1)
- 26023, Conduct of Infrequently Performed Tests or Evolutions (SOER 91-1)
- 26082, Licensed Operators Review Unit Differences Prior to New Unit Duties
- 26102, First Time Performance of Sensitive Tasks
- 26110, Individual Performance Corrective Actions
- 26708, Inadequate Evolution Preparation
- 26760, Operational Challenges During Dual Unit Work or Testing
- 4447146, IERL2-12-38 Reactor Trip and Generator Lockout Rec. 1

4.0 DEFINITIONS/ACRONYMS

4.1 At the Controls Area - The area described in STA-616.

4.2 Operations Shift Orders - An Operations management directive to Shift Operations describing the work to be accomplished during the Shift and information to be passed on to their reliefs.

4.3 NEO - Nuclear Equipment Operator

4.4 Shift Turnover Briefing - A meeting normally conducted with the entire on-coming crew chaired by the on-coming Shift Manager (or representative).

4.5 Short Term Relief - A process to allow for brief absences from duty for Shift Operating personnel not expected to be absent for more than 60 minutes.

4.6 SOMS (Shift Operations Management System) - An electronic program used to manage the process of creating and maintaining an interactive journal for recording and qualifying events which occur during a shift.

4.7 Pre-job Brief – An interactive preparatory meeting or discussion conducted before performing a task, designed to ensure the safe and efficient execution of the task.

4.8 Post-job Critique – A routine self-assessment practice conducted after task completion to evaluate task performance and to provide feedback for lessons learned to identify and correct potential weaknesses for future task performance.

4.9 Task – An identifiable segment of work that is assigned to achieve a desired purpose.

4.10 Job – A bundle of work that may consist of a single task or may include multiple tasks.

4.11 Heightened Level of Awareness Activity - Any activity which significantly increases chances of unplanned power reductions or plant trip. When the plant is shutdown, this defines activities that reduce defense in depth measures.

4.12 High Risk Activity - Any activity that places the plant in a configuration that could significantly degrade the level of nuclear safety or presents a serious industrial safety hazard.

4.13 Infrequent Evolutions - Any activity that involves complex sequencing or coordination of several work groups that has not been performed in the previous 6 months by the key performers involved with the activity. Some activities may have such a high consequence of failure (such as fuel movement) that they should be classified as Infrequent, even if they have been performed in the past 6 months.

4.14 Infrequently Performed Test or Evolution (IPTE) - An evolution meeting the criteria of, and requiring a Senior Line Manager to participate in the pre-evolution briefing and to exercise continuous oversight of the evolution per STA-122.

5.0 RESPONSIBILITIES

5.1 Shift Manager

- Ensures proper implementation of the turnover process.
- Ensures the Technical Specifications shift manning requirements are fulfilled.
- Ensures pre-job briefs and post-job critiques are performed as required.

5.2 Operations Personnel

- Perform turnovers in accordance with the requirements of this instruction.
- Perform pre-job briefs and post-job critiques as required.

5.3 Operations Support Supervisor - Maintains this instruction current.

5.4 SOMS Coordinator – Maintains the SOMS Narrative Log Module.

6.0 INSTRUCTIONS

6.1 Turnover

6.1.1 Turnover - General Information

[C] A. The plant shall be in a stable condition prior to shift relief. System operations, tests or other activities should be scheduled such that steady-state conditions exist during shift turnover. Shift relief should not be conducted during plant transients or during major steps of an evolution (i.e., Significant Load Changes, Reactor Startups, etc.). Vigilance shall be maintained during shift turnover to ensure that all plant conditions and evolutions in progress are understood prior to accepting responsibility for the position. The Shift Manager may delay turnover until plant conditions are acceptable or require that turnover occur on-station in a controlled manner. Should conditions require turnover to occur on-station, both persons involved should be informed of this requirement. [23458]

[C] B. Individual watch-station turnover should be held prior to the Shift Turnover Briefing for the on-coming shift crew. The Shift Turnover Briefing should be used to discuss current plant status, planned evolutions, shift goals, new Standing Orders, current lessons learned, applicable PIRs and any major administrative or operating procedure changes or revisions. This briefing may also include representatives from other departments directly supporting Shift Operations (e.g., Prompt Team, Chemistry, etc.). A Shift Briefing Checklist (OWI-107-15), attached to the Shift Manager Relief Checklist, may be completed and utilized by the off-going Shift Manager to ensure the briefing includes all required information. [23474, 23627]

C. Shift Turnover shall be conducted in a timely and professional manner. Only personnel fit for duty shall be permitted to assume a shift position. The final determination of fitness for duty shall be made by the Shift Manager.

D. Shift Operations personnel assigned positions for which a relief checklist is provided should continue with the duties of that position until formally relieved of their duties by a qualified individual through completion of the relief and dismissal process.

E. Personnel fulfilling a required position, such as Fire Brigade or Emergency Response team member, should remain on-duty until a qualified relief is present.

F. Formal relief is complete when the off-going person and the on-coming person both sign as indicated on the relief checklist, AND the on-coming person signifies that the duties of the position have been assumed.

6.1.1 G. The relief checklists are used during the relief process as an aid to ensure that an efficient turnover is conducted. In addition to the relief checklist, information may be recorded on the Relief Notes (OWI-107-16). If additional sheets are used, they should be attached to the associated checklist.

H. When all turnover activities are completed, the ON-COMING watch-station individual (RO, BOP, SM, US, STA, FSS, etc.) will assume the watch from the OFF-GOING watch-station individual (RO, BOP, SM, US, STA, FSS, etc.) in the eSOMS Narrative Log Module. Log in to the eSOMS Narrative Log Module should occur after the Shift Turnover Briefing, normally between 0615 to 0630, or 1815 to 1830.

I. After assuming the shift position, a new relief checklist should be initiated for use during the next shift relief. To the extent practical, the relief checklist should be maintained throughout the shift as opposed to being completed just prior to shift relief.

J. Completed relief checklists should be submitted to the applicable Supervisor for required reviews.

6.1.2 <u>Turnover for Licensed and Supervisory Positions</u>

[C] A. A single Reactor Operator shall not assume responsibility for the controls of both units at the same time. [08294]

B. Each licensed and supervisory position should conduct the major portion of relief separately. Following their individual turnovers, as a minimum, the SM and USs should assemble to ensure that a complete and accurate exchange of information has occurred.

[C] C. Part I of the relief checklist should be prepared by the off-going person. The on-coming person signifies understanding of this information when the SHIFT RELIEF section of the checklist is signed upon completion of turnover. The following information should be provided by the off-going person: [08295]

<u>Shift Activities</u> - This should include surveillances, work activities, AND system or component manipulations that were either recently completed, in progress or are planned to occur. It is especially important to include all evolutions which are in progress (or suspended for relief turnover).

[C] <u>Plant and Equipment Status</u> - This shall include a summary of all active LCOARs in which action is required within 72 hours. This summary should include both the LCOAR and Technical Specification numbers, all Special Condition surveillances and associated frequency, a brief description of the equipment involved and the applicable work order, if any, addressing the condition. A status summary of non-safety plant systems and any associated problems should also be included. This section should be reviewed concurrently with the Special Condition Status Board. [23486]

<u>General Information</u> - This section may be used to provide any other information as necessary.

6.1.2 D. Part II of the checklist is to be completed by the on-coming person. The following should be completed:

Critical Parameters - The values for these parameters should be recorded in the space provided, and these values should be determined to be within normal operating limits, or otherwise so noted.

[C] Status Review - Items in this section include reviews of logs and operating orders. All status reviews should be completed prior to shift relief except as indicated on the individual turnover sheets. [08295]

The review of Station and Unit Narrative Logs should include a review of the period since the on-coming person's last on-duty shift, not to exceed five days.

For each separate watch-station, the off-going and on-coming Licensed Operators (RO, BOP, US, SM) are to conduct a Control Board walk-down together. If the off-going watchstander is not available to participate in a board walkdown due to plant activities and it is not desire to delay turnover, then another individual from the off-going crew may conduct the board walk-down with the indisposed watchstander's relief (e.g., on-coming RO could participate in the US board walk-down).

[C] A Control Board walkdown should include the Main Control Board area (CB-1 through CB-11), the Ventilation Panels, NIS Panel, and the Recorder Panel CV-04 (Main Turbine recorders) of the Unit for which person is assuming the watch. Walkdown should also include the Switchyard Panel (CB-12), the Fire Detection Panel (CV-06), and Met Tower recorders. Additionally, annunciator alarms, SSII lights, MLBs and TSLBs shall be reviewed and the reason for each alarm condition understood. [4447146]

The Shift Manager:

- Shall ensure that Technical Specification shift manning requirements are met prior to accepting the position. Completion of the shift manning portion of the turnover form is allowed after shift relief.
- Should review the Temp Mod log for any changes and ensure any notable changes are covered at turnover.

Additional items for review or performance are located on the specified checklists.

The on-coming operator signifies completion of their review by signing the SHIFT RELIEF section of the checklist.

[C] 6.1.2 E. The STA shall review the SM Relief Checklist and plant logs and sign as indicated on the Shift Manager Relief Checklist. [14851]

[C] F. Each Licensed Operator (RO, BOP, US) shall review the applicable Unit Differences document prior to assuming duties on a unit that he/she was not assigned to on a previous shift. [26082]

G. As part of the shift turnover process, the Unit 2 Supervisor(s) and ROs should review the LCOAR Log and the Systems Important to Safety Log (SISL) for Unit 1 to familiarize themselves with degraded conditions on common equipment.

H. The SM and FSS will review the US relief checklist for both units. The US will review the respective RO/BOP relief checklist.

I. The Field Support Supervisor will review all NEO relief checklists.

[C] 6.1.3 Turnover for Nuclear Equipment Operators [05240]

A. A NEO may assume more than one watch station only by direction of the SM.

B. Each on-coming NEO, who is designated to do so, should pick up security keys prior to assuming the position.

C. The information in Part I of the relief checklist should be prepared by the off-going operator. The on-coming operator signifies understanding of this information when the SHIFT RELIEF section of the checklist is signed upon completion of turnover.

D. Part II of the relief checklist should be completed by the oncoming person prior to accepting the watch.

E. The on-coming operator signifies completion of turnover by signing the SHIFT RELIEF section of the checklist.

F. Part III of the OWI-107-13, Radwaste Operator Relief Checklist should be completed by the on-coming Fire Brigade Leader. The on-coming Fire Brigade Leader reviews the active fire impairments and signifies completion of this review by signing Part III of the checklist.

G. In the event a casualty or plant transient occurs prior to completion of shift turnover, the OFF-GOING crew will be the response crew with assistance provided by the ON-COMING crew as needed. Once the plant is stable, turnover may be completed and the OFF-GOING crew dismissed.

H. The OFF-GOING NEOs may not depart the site until released by the ON-COMING SM or his/her designee.

I. When all turnover activities are completed, the ON-COMING NEO will assume the watch from the OFF-GOING NEO in the Narrative Log Module.

6.1.4 Short Term Relief

Short term reliefs should be used whenever shift operating personnel will be out of the "at the controls" area for periods projected to last for $\leq$ 60 minutes. This is not required for brief absences such as trips to the rest room, kitchen, CPC, SM office, etc. Short term relief may occur only if all of the following conditions are met:

- The on-coming person is qualified for the position.
- The on-coming person is knowledgeable of all pertinent activities in progress.
- A joint board walkdown is performed, as applicable, and
- The SM grants permission if a Supervisor requires relief. The Unit Supervisor grants permission if the RO or BOP assigned to their Unit requires relief.

Reliefs expected to last for a longer duration should be performed by completion of the associate relief checklist for that position and should be documented in the Narrative Log Module.

[C] 6.2 Pre-Job Briefs [26760, 23463, 26708, 26102, 26110]

6.2.1 Pre-job Briefs - General Information

A. Briefings shall be conducted following the guidelines of STI-429.04. The Unit Supervisor or Work Window Manager normally determines the extent of briefing required.

B. Operations briefs normally take place in the Quiet Room area of the Control Room, but may take place in any suitable location.

C. Operations briefs are normally conducted by the individual that is most responsible for the task or job. This may be the Unit Supervisor, Reactor Operator, or the Nuclear Equipment Operator.

D. Standardized Pre-job Briefs may be used from a department maintained database, but should be verified for applicability and accuracy prior to use.

[C] 6.2.2 Pre-job Briefs - Infrequently Performed Tests or Evolutions (IPTEs) [26022, 26023]

A. The Senior Line Manager designated by the Plant Manager ensures proper performance of the Pre-job brief for the IPTE per STA-122. The Senior Line Manager may assign a designee to complete the IPTE Pre-job brief.

B. If the IPTE extends beyond one shift, the on-coming crew will be briefed for the IPTE aspects of the test or evolution by the Senior Line Manager, or designee. The IPTE brief should not interfere or occur concurrently with the shift operations turnover unless approved by the SM.

C. The Pre-job brief for an IPTE is controlled via STA-122-4, “IPTE Pre-job Brief Presentation Checklist” and should be presented using the attributes of STI-429.04.

D. The Shift Operations crew responsible for conducting the IPTE should prepare for the Pre-job brief per the requirements of Section 6.2.1 in order to be knowledgeable of the test or evolution and to allow considerations for the activity requirements.

6.2.3 Pre-job Briefs - High Risk, Heightened Level of Awareness, Infrequent Evolution

A. Classification of activities as High Risk, Heightened Level of Awareness or Infrequent Evolutions should be done by the WC SRO or the SM. During absence of the SM, activity classification may be performed by his/her designee. These activities should normally be preplanned and scheduled as part of the Plan of the Day (POD).

If a High Risk activity is identified due to a potential degradation of nuclear safety, the evolution should be reviewed against the IPTE criteria per STA-122.

B. An activity classified as a High Risk, Heightened Level of Awareness, or Infrequent Evolution should be considered a candidate for Management Observation per STA-122, Attachment 8.B.

C. The designated performer of a Management Observation for any High Risk, Heightened Level of Awareness or Infrequent Evolution is a manager, or designee for the work group controlling the activity (e.g., Shift Manager or designee for Operations Department led activity, Maintenance Manager or designee for Maintenance Department led activity, observer designated by Plant Manager, Operations, Director, etc.).

D. A formal briefing shall be held for all High Risk, Heightened Level of Awareness, and Infrequent Evolutions.

E. The Shift Manager should be present at any High Risk briefing. If the activity involves a maintenance activity, a Maintenance Manager should also be present at any High Risk briefing.

F. The Unit supervisor is expected to be the SRO in charge of High Risk, Heightened Level of Awareness, and Infrequent Evolutions and should give full attention to the activity.

- Activities that can distract the operators or US should be avoided, or an extra SRO should be assigned. The Extra SRO should monitor routine activities for the unit while the Unit Supervisor is involved in the special activity. This responsibility may be reversed at the Shift Manager's discretion.

- If necessary, the SM should determine if the FSS or a Maintenance Supervisor should provide observation of the HRA, HLA or IFE activity in the plant.

6.2.3 G. The Unit supervisor should ensure the individuals performing any High Risk, Heightened Level of Awareness, or Infrequent Evolution:

- Have performed the evolution previously,
- **OR** are being directly observed by a person experienced in the evolution,
- **OR** have been trained on the specific evolution.

H. Examples of High Risk Activities:

- special tests or experiments as defined in Federal Regulations.
- Freeze seals with the potential to directly impact RCS inventory.
- Tests, evolutions or troubleshooting that could place the plant in an unusual configuration (not defined by SOPs, RWSs, or ABNs) and have the potential to significantly decrease plant safety.
- Entry into a Confined Space or Hazardous Area considered to be Immediately Dangerous to Life and Health (IDLH).

I. Examples of Heightened Level of Awareness Activities:

- Replacing a positioner on a feedwater flow control valve.
- Reduction in Defense in Depth provisions during an outage.
- Reactor Trip Breaker Testing/SSPS Logic testing.
- Aligning or shifting air supplies to the Spent Fuel Pool or Containment gate seal when a level difference exists across the gate.
- Turbine Stop and Control Valve testing.
- Switchyard maintenance not approved per STA-629.

6.2.3 J. Examples of Infrequent Evolutions:

- Reducing Reactor Coolant level below the pressurizer indicating range.
- Periodic integrated safeguards testing.
- Integrated leak rate testing.
- Initial criticality following a refueling outage.
- Any irradiated fuel movement activities or movement of heavy loads in the vicinity of the core or spent fuel storage when irradiated fuel is present.
- Freeze seals.

[C] 6.3 Post-Job Critiques [23463]

6.3.1 Post-Job Critiques - General Information

A. Post-Job Critiques are conducted in order to obtain immediate feedback or lessons learned and to facilitate sharing of that information with department personnel per STI-429.04.

B. Information gathered during the Post-Job Critique which would benefit future performance of a task should be entered in the department Post Job Critique computer database. This will allow referencing the information for future performances.

C. A post-job critique should be conducted to review the results of troubleshooting. Attention should be paid to the following:

- Before the troubleshooting is declared complete and the system is declared operable, review the symptoms of the original problem to ensure they have all been addressed. Verify that the suspected causes and corrective actions are consistent with the symptoms.
- Avoid declaring victory simply because the symptoms of the problem have disappeared.
- Operability tests are focused on specific system parameters and do not ensure that all required design features of the equipment or system are functional.
- Encourage anyone who may have doubts remaining upon completion of troubleshooting to bring them out into the open for discussion and resolution before declaring the system operable.

D. IF needed actions are identified, THEN the action should documented using a station tracking process (CR, Procedure Change Request, etc.) to ensure resolution.

7.0 FIGURES

None

8.0 ATTACHMENTS/FORMS

8.1 ATTACHMENTS

None

8.2 FORMS

8.2.1 OWI-107-1, “Shift Manager Relief Checklist - Common”

8.2.2 OWI-107-2, “Unit Supervisor Relief Checklist”

8.2.3 OWI-107-5, “RO\BOP Operator Relief Checklist”

8.2.4 OWI-107-6, “Safeguards Building Operator Relief Checklist”

8.2.5 OWI-107-7, “Auxiliary Building Operator Relief Checklist”

8.2.6 OWI-107-9, “Unit 1 Turbine/ECB Building Operator Relief Checklist”

8.2.7 OWI-107-10, “Unit 2 Turbine/ECB Building Operator Relief Checklist”

8.2.8 OWI-107-11, “Perimeter Operator Relief Checklist”

8.2.9 OWI-107-13, “Radwaste Operator Turnover Checklist”

8.2.10 OWI-107-15, “Shift Briefing Checklist”

8.2.11 OWI-107-16, “Relief Notes”

8.2.12 OWI-107-17, “Shift Roster”

9.0 RECORDS

When completed, the following forms, reports, or other documents generated in response to this procedure should be dispositioned in accordance with STA-302, "Station Records".

None

Rev/PCN	Affected Pages	Description of Change
8 / 0	All	Updated format for size 11 font, CPNPP vice CPSES. Added Level of Use per STA-201. Added Commitment references to Reference Section and tied to applicable incorporating procedure instruction. Added reference to Step 6.2.2 for Commitments regarding Infrequently Performed Tests or Evolutions (IPTE).
8 / 1	1, 7, 9	Modified instructions to clarify management expectations for the log-in to the eSOMS Narrative Log Module to be performed after the Shift Turnover briefing with specific times expected for the turnover to occur. (AI-CR-2011-007579-2)
8 / 2	1, 3, 8	Editorial enhancement that adds new commitment [4447146] to reference section and to 6th paragraph under step 6.1.2 D.
8 / 3	1, 9	Added step 6.1.3.F for Fire Brigade Leader review of active fire impairments. Renumbered subsequent steps. AI-CR-2012-006524-8
8/4	1, 3	Editorial update of cover page. Editorial PCN in Section 3.0 References added commitment 23316 and SOER 87-01, "Core Damaging Accident Following an Improperly Conducted Test". Refer to SOER 87-1 & CDF 23316. AI-CR-2012-013160-5.
8/5	1, 12	Update step 6.2.3 B to be consistent with STA-122 by changing the requirement for management observation to be optional. (AI-CR-2015-1372-1)
8/6	1, 3, 11, 14	Replaced references to STA-123 with STI-429.04 throughout the procedure per AI-CR-2015-003782-26.

Four Reactor Operators have the following history:

- All four are current in License Operator Requalification Training and have had a medical examination in the past 2 years.
- Active/Inactive status and time on shift since January 1, 2017 is as follows for each of the Reactor Operators:

- **RO # 1** was active on January 1, 2017
  1/02/17 - worked 0600-1800 shift as RO
  1/03/17 - worked 0600-1800 shift as BOP
  2/04/17 - worked 0600-1800 shift as RO
  3/14/17 - worked 0600-1800 shift as CPC RO
  3/31/17 - worked 0600-1800 shift as RO

- **RO # 2** was inactive on October 1, 2016
  01/02/17 thru 01/06/17 worked 40 hours under the direction of the RO and completed all requirements for reactivation including a plant tour
  2/10/17 - worked 0600-1800 shift as BOP
  3/12/17 - worked 0600-1800 shift as RO
  3/14/17 - worked 0600-1800 shift as RO
  3/31/17 - worked 0600-1800 shift as BOP

- **RO # 3** Received a Reactor Operator License from the NRC on 3/15/2017
  Has not stood a shift this quarter

- **RO# 4** was active on January 1 2017
  12/31/16 - worked 1800-0600 as BOP
  2/18/17 - worked 0600-1800 shift as BOP, was relieved by another operator for 2 hours to attend a dentist appointment
  2/19/17- worked 0600-1800 shift as BOP
  3/11/17 - worked 0600-1800 shift as RO
  3/14/17 - worked 1800-0600 shift as BOP
  3/30/17 - worked 1800-0600 shift as RO

ACTIVE LICENSE STATUS FORM

SECTION I - GENERAL

NAME: ______________________________ EID#: ____________

LAST FIRST MI

LICENSE TYPE: RO: ____ SRO: ____

LICENSE UNIT: ONE: ____ DUAL: ____

APPLICABLE CALENDAR QUARTER, YEAR: ____________

________ 1st (JAN 1 - MARCH 31)

________ 2nd (APRIL 1 - JUNE 30)

________ 3rd (JULY 1 - SEPT 30)

________ 4th (OCT 1 - DEC 31)

SECTION II - CERTIFICATION OF HOURS

This is to certify that I have completed at least five (5) 12-hour shifts in a responsible position* which requires an Active License and documentation in the appropriate Unit or Station Log in accordance with ODA-315, Section 6.2.1.

____________________ / ______________

* Position may be: US, SM, Fuel Handling SRO, RO, BOP, or Steam Generator Operator

SECTION III - MISCELLANEOUS RECURRENT TRAINING AND QUALIFICATIONS

This is to certify that I have reviewed my miscellaneous recurrent training and qualifications* status and that my training has not expired in any areas. I am aware of any near-term expiration dates and am prepared to maintain a current status. I also possess a pair of respirator glasses if so required**.

____________________ / ______________

* Reference Operations Guideline No. 15, “Operations Department Miscellaneous Recurrent Training and Qualifications”

** Reference Operations Guideline No. 16, “Personnel Related Policies”

SECTION IV - ACKNOWLEDGEMENT

The above listed Licensed Operator is “current” in all phases of training per TRA-203 or TRA-204 and has satisfied the requirements to remain Active per 10CFR55.53.

____________________________ / ____________

Shift Operations Management

Comments/Exceptions: ____

____

FORWARD THE COMPLETED FORM TO THE SHIFT OPERATIONS DEPARTMENT STAFF

Initial Conditions: **Given the following conditions:**

- **The plant was at 100% power, when the RO had a medical emergency and will not be able to work his next scheduled shift. The Operations Shift Attendant has contacted four off shift individuals to replace the RO on the following day.**
- **Today is April 6, 2017.**
- **Four Staff Reactor Operators are available to be assigned as the Unit 1, RO for the April 6th day shift.**
- **Given the first quarter shifts were worked as recorded in the Unit and Station Logs on the Handout.**
- **Unit 1 had unit trip on 3/12 and returned to power on 3/14.**
- **Unit 2 maintained 100% power during the first quarter.**

Initiating Cue: **The Shift Manager directs you to PERFORM the following:**

- **DETERMINE which Reactor Operators are current on maintaining proficiency of an Active License. (Circle Correct Status)**

  - **RO #1** **Active** **Inactive**
  - **RO #2** **Active** **Inactive**
  - **RO #3** **Active** **Inactive**
  - **RO #4** **Active** **Inactive**

- **DETERMINE which Reactor Operator(s) satisfy the requirements to fill the Unit 1, RO position for the oncoming shift.**

  - **RO(s) 2 and 3 can be assigned as the Unit 1 RO.**

Facility: CPNPP JPM # NRC SA3 Task # SO1202B K/A # 2.2.12 3.7 / 4.1

Title: Perform Control Room AC System Surveillance Data / Evaluate Technical Specifications

Examinee (Print): ______________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Both Units are operating at 100% power with all controls in Automatic.
- Train B Control Room Air Conditioning System is being tested per OPT-116, CR AC SYSTEM
- The 30 minute run time since completion of the Prerequisites is complete.
- The following parameters are observed:
  - CR A/C UNIT 03- X-PI-3585A reads 150 psig and is operating 45% unloaded
  - CR A/C UNIT 04 -X-PI-3586A reads 160 psig and is operating 35% unloaded
  - X-TR-4123 reads 75°F
  - X-TI-5933 reads 63°F
  - X-TI-5734 reads 64°F
  - X-TI-5735 reads 62°F

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- COMPLETE the Control Room Air Conditioning System surveillance per OPT-116, CR AC SYSTEM
- RECORD and COMPLETE all data on OPT-116-1, CR AC System Data Sheet
- If required, IDENTIFY any Technical Specification LCO CONDITION, REQUIRED ACTION, and COMPLETION TIME and record in Comments Section of surveillance

Task Standard: UTILIZED OPT-116, RECORDED data on OPT-116-1, PLOTTED air conditioning unit cooling capacity, DETERMINED Acceptance Criteria met, and DETERMINED and Technical Specification LCO CONDITIONs, REQUIRED ACTIONs, and COMPLETION TIMEs that applied .

Required Materials: OPT-116, CR AC System, Rev. 5.
OPT-116-1, CR AC System Data Sheet, Rev. 5.
Unit 1 Technical Specifications, Amendment 165.

Validation Time: 15 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ____ Date: ______________

CLASSROOM SETUP

EXAMINER:
PROVIDE the examinee with a copy of:

- **OPT-116, CR AC System (Procedure 1)**
- **OPT-116-1, CR AC System Data Sheet (Form)**
- **Unit 1 Technical Specifications (Procedure 2)**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from OPT-116, Section 8.0.**
Perform Step: 1 8.3 & 1st bullet	RECORD the following: • X-TR-4123, outside temperature (10M PRI) (X-CV-05)
Standard:	RECORDED X-TR-4123, outside temperature of 75°F on OPT-116-1 and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2 8.3 & 2nd bullet	RECORD the following: • X-TI-5933 ECB EXH TEMP (X-CV-01)
Standard:	RECORDED X-TI-5933, ECB EXH TEMP of 63°F, on OPT-116-1 and COMPARED to Required Test Conditions of ≥ 60 degrees and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3 8.3 & 3rd bullet	RECORD the following: • X-TI-5734, AB EXH TEMP EL-852' 6" (X-CV-03)
Standard:	RECORDED X-TI-5734, AB EXH TEMP of 64°F on OPT-116-1 and COMPARED to Required Test Conditions of ≥ 60 degrees and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4 8.3 & 4th bullet	RECORD the following: • X-TI-5735, AB EXH TEMP EL-831' 6" (X-CV-03)
Standard:	RECORDED X-TI-5735, AB EXH TEMP of 62°F, on OPT-116-1 and COMPARED to Required Test Conditions of ≥ 60 degrees and INITIALED.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 5 8.3 & 5th bullet	RECORD the following: • Compressor discharge pressures for operating A/C units. ◦ CR A/C Unit 03 (X-PI-3585A)	
Standard:	RECORDED CR A/C Unit 03 (X-PI-3585A) pressure of 150 psig on OPT-116-1 and COMPARED to Required Test Conditions of < 170 psig and INITIALED.	
Comment:		**SAT** ☐ **UNSAT** ☐

Perform Step: 6 8.3 & 5th bullet	RECORD the following: • Compressor discharge pressures for operating A/C units ◦ CR A/C Unit 04 (X-PI-3586A)	
Standard:	RECORDED CR A/C Unit 04 (X-PI-3586A) pressure of 160 psig on OPT-116-1 and COMPARED to Required Test Conditions of < 170 psig and INITIALED.	
Comment:		**SAT** ☐ **UNSAT** ☐

<u>Examiner Cue:</u>	**If asked about Independent Verification (IV), REPORT to proceed as if the IV has been performed.**	
Perform Step: 7√ 8.4	VERIFY the above readings are within the specified limits. If any of the above readings are <u>NOT</u> within the specified limits, this test should be terminated and restarted when the above conditions can be met.	
Standard:	VERIFIED that all readings are within limits and INITIALED.	
Comment:		**SAT** ☐ **UNSAT** ☐

Perform Step: 8 8.5	RECORD % unloaded (lights on A/C Unit Control Panel) for both operating A/C units. • A/C UNIT 03	
Standard:	RECORDED A/C UNIT 03 % unloaded of 45% on OPT-116-1 and INITIALED.	
Comment:		**SAT** ☐ **UNSAT** ☐

Perform Step: 9 8.5	RECORD % unloaded (lights on A/C Unit Control Panel) for both operating A/C units. • A/C UNIT 04	
Standard:	RECORDED A/C UNIT 04 % unloaded of 35% on OPT-116-1 and INITIALED.	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 10√ 8.6	CALCULATE the average % unloaded by adding the % unloaded from the operating compressors and dividing by 2.	
Standard:	ADDED 45% and 35% and DIVIDED by 2 to yield an average of 40%; RECORDED on OPT-116-1 and INITIALED.	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 11 8.7	Using outside temperature (Step 8.3) and the calculated average compressor cooling capacity availability (Step 8.6), VERIFY operation is above the curve (Figure 1) in the data sheet, <u>AND</u> RECORD test results.	
Standard:	PLOTTED the intersection point for 75 degrees and 40% on Figure 1 and COMPARED to the acceptability curve.	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 12√ 8.7	Using outside temperature (Step 8.3) and the calculated average compressor cooling capacity availability (Step 8.6), VERIFY operation is above the curve (Figure 1) in the data sheet, <u>AND</u> RECORD test results.	
Standard:	VERIFIED plotted point is BELOW the curve on Figure 1 and CIRCLED BELOW then UNSAT on OPT-116-1 and INITIALED.	
Comment:		**SAT ☐ UNSAT ☐**

<u>Examiner Note:</u>	**The following is from Technical Specification LCO 3.7.11.**
Perform Step: 13√	RECORD any required Technical Specification CONDITION, REQUIRED ACTION, and COMPLETION TIME in the Comments Section of the Surveillance.
Standard:	DETERMINED entry into Technical Specification LCO 3.7.11, Control Room Air Conditioning System (CRACS): • CONDITION A – One CRACS train inoperable; • REQUIRED ACTION A.1 – Restore CRACS train to OPERABLE status. • COMPLETION TIME – Within 30 days.
<u>Terminating Cue:</u>	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Both Units are operating at 100% power with all controls in Automatic.**
- **Train B Control Room Air Conditioning System is being tested per OPT-116, CR AC SYSTEM**
- **The 30 minute run time since completion of the Prerequisites is complete.**
- **The following parameters are observed:**
  - **CR A/C UNIT 03- X-PI-3585A reads 150 psig and is operating 45% unloaded**
  - **CR A/C UNIT 04 -X-PI-3586A reads 160 psig and is operating 35% unloaded**
  - **X-TR-4123 reads 75°F**
  - **X-TI-5933 reads 63°F**
  - **X-TI-5734 reads 64°F**
  - **X-TI-5735 reads 62°F**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **COMPLETE the Control Room Air Conditioning System surveillance per OPT-116, CR AC SYSTEM**
- **RECORD and COMPLETE all data on OPT-116-1, CR AC System Data Sheet**
- **If required, IDENTIFY any Technical Specification LCO CONDITION, REQUIRED ACTION, and COMPLETION TIME and record in Comments Section of surveillance**

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1&2

OPERATIONS TESTING MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS Today / JR LATEST PCN/EFFECTIVE DATE ______ / ______

LEVEL OF USE:
CONTINUOUS USE

QUALITY RELATED

CR AC SYSTEM

PROCEDURE NO. OPT-116

REVISION NO. 5

EFFECTIVE DATE: 7/14/14 1200

SURVEILLANCE TEST

PREPARED BY (Print): J.D. STONE EXT: 0564

TECHNICAL REVIEW BY (Print) EDITORIAL REVISION EXT: NA

APPROVED BY: Joe Ricks DATE: 7/3/14
DIRECTOR, OPERATIONS

1.0 PURPOSE

This procedure verifies each CRACS train has the capability to remove the assumed heat load satisfying SR 3.7.11.1 requirements.

2.0 ACCEPTANCE AND REVIEW CRITERIA

2.1 Acceptance Criteria

2.1.1 The acceptance criteria are listed on the data sheet.

2.2 Review Criteria

None

3.0 DEFINITIONS/ACRONYMS

3.1 CRACS - Control Room Air Conditioning System

4.0 REFERENCES

4.1.1 Technical Specification 3.7.11, Control Room Air Conditioning System (CRACS)

4.1.2 Technical Requirements Manual 13.7.36, Area Temperature Monitoring"

4.2 Development

4.2.1 FSAR Section 6.4, Habitability System

4.2.2 FSAR Section 9.4, Air Conditioning, Heating, Cooling, and Ventilation Systems

4.2.3 DBD-ME-304, Control Room Air Conditioning System

4.2.4 M1-0304, Flow Diagram Ventilation Control Room & Office & Service Area

4.2.5 M1-0308, Flow Diagram Ventilation Control Room Mode of Operation

4.2.6 ABN-203, Control Room Ventilation System Malfunction

5.0 PRECAUTIONS, LIMITATIONS AND NOTES

5.1 Precautions

None

5.2 Limitations

5.2.1 Two CRACS trains shall be OPERABLE per the requirements of TS 3.7.11.

5.2.2 The temperature limits for normal conditions shall be per the TRM 13.7.36.

5.3 Notes

- A time delay prevents the start of a CRAC when taken from PULL-OUT position. Following removal from PULL-OUT, take the handswitch to STOP position. The CRAC may then be started following time delay dropout (approximately thirty seconds).

6.0 PREREQUISITES

☑ • This test may be performed with both units in any MODE.

☑ • When outside ambient temperature is <30°F this test may be performed with only 1 A/C unit operating. This is NOT the preferred method.

☑ • WHEN outside ambient temperature is ≥30°F (X-TR-4123), the CR A/C units should be aligned as follows:

Train A Test

N/A ☐ A/C Units 01 & 02 operating

☑ A/C Units 03 & 04 shutdown

Train B Test

☑ A/C Units 03 & 04 operating

☑ A/C Units 01 & 02 shutdown

☑ • The Control Building exhaust temperature (X-TI-5933) AND Auxiliary Building exhaust temperatures (X-TI-5734, X-TI-5735) from elevations 852" 6" and 831' 6" are ≥60°F.

☑ • The compressor discharge pressures are <170 psig for the operating A/C units.

☑ • RECORD the time and date the above prerequisites are verified to be met. These conditions shall be met for at least 30 minutes prior to starting Section 8.0.

7.0 TEST EQUIPMENT

None

8.0 INSTRUCTIONS

NOTE: Record all data on Form OPT-116-1.

☑ 8.1 RECORD CR A/C Unit(s) being tested.

☑ 8.2 RECORD time and date (shall be ≥30 min. from time recorded in Prerequisite section).

8.3 RECORD the following:

- ☐ X-TR-4123, outside temperature (10M PRI) (X-CV-05)
- ☐ X-TI-5933, ECB EXH TEMP (X-CV-01)
- ☐ X-TI-5734, AB EXH TEMP EL-852' 6" (X-CV-03)
- ☐ X-TI-5735, AB EXH TEMP EL-831' 6" (X-CV-03)
- ☐ Compressor discharge pressures for operating A/C units.

  CR A/C Unit 01 (X-PI-3583A)
  CR A/C Unit 02 (X-PI-3584A)
  CR A/C Unit 03 (X-PI-3585A)
  CR A/C Unit 04 (X-PI-3586A)

☐ 8.4 VERIFY the above readings are within the specified limits. If any of the above readings are NOT within the specified limits, this test should be terminated and restarted when the above conditions can be met.

☐ 8.5 RECORD % unloaded (lights on A/C Unit Control Panel) for both operating A/C units.

[IV] ☐ 8.6 CALCULATE the average % unloaded by adding the % unloaded from the operating compressors and dividing by 2.

A/C UNIT NO.__________ A/C UNIT NO.__________

$$\frac{\text{\% UNLOADED\_\_\_\_\_\_} + \text{\% UNLOADED\_\_\_\_\_\_}}{2} = \text{TRAIN AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY}$$

NOTE: Operation above the curve contained in the data sheet verifies that the CRACS has the capability to remove the assumed heat load satisfying SR 3.7.11.1 requirements.

☐ 8.7 Using outside temperature (Step 8.3) and the calculated average compressor cooling capacity availability (Step 8.6), VERIFY operation is above the curve (Figure 1) in the data sheet, AND RECORD test results. (CONTACT Engineering if this test was performed at ambient outside temperature <20°F to determine test results).

☐ 8.8 ALIGN CR A/C Units as directed by the Shift Manager (normally per appropriate workweek as designated in OWI-409, Equipment Rotation Program).

9.0 RESTORATION

None

10.0 ATTACHMENTS/FORMS

10.1 Attachments

None

10.2 Forms

10.2.1 OPT-116-1, CR A/C System Data Sheet

TECHNICAL SPECIFICATIONS

FOR

COMANCHE PEAK NUCLEAR POWER PLANT

UNITS 1 AND 2

TABLE OF CONTENTS

1.0 USE AND APPLICATION

1.1 Definitions

-- NOTE --
The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state required for OPERABILITY of a logic circuit and the verification of the required logic output. The ACTUATION LOGIC TEST, as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of an excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping or total channel steps.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

1.1 Definitions (continued)

CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints required for channel OPERABILITY so that the setpoints are within the necessary range and accuracy. The COT may be performed by means of any series of sequential, overlapping or total channel steps.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries per gram) that alone would produce the same dose when inhaled as the combined activities of iodine isotopes I-131, I-132, I-133, I-134, and I-135 actually present. The determination of DOSE EQUIVALENT I-131 shall be performed using thyroid dose conversion factors from Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites," or from Table E-7 of Regulatory Guide 1.109, Revision 1, NRC, 1977, or from ICRP-30, 1979, Supplement to Part 1, page 192-212, Table titled “Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity,” or from Table 2.1 of EPA Federal Guidance Report No. 11, 1988, “Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion.”

1.1 Definitions (continued)

DOSE EQUIVALENT XE-133	DOSE EQUIVALENT XE-133 shall be that concentration of Xe-133 (microcuries per gram) that alone would produce the same acute dose to the whole body as the combined activities of noble gas nuclides Kr-85m, Kr-87, Kr-88, Xe-133m, Xe-133, Xe-135m, Xe-135, and Xe-138 actually present. If a specific noble gas nuclide is not detected, it should be assumed to be present at the minimum detectable activity. The determination of DOSE EQUIVALENT XE-133 shall be performed using effective dose conversion factors for air submersion listed in Table III.1 of EPA Federal Guidance Report No. 12, 1993, "External Exposure to Radionuclides in Air, Water, and Soil", or using the dose conversion factors from Table B-1 of Regulatory Guide 1.109, Revision 1, NRC, 1977.
ENGINEERED SAFETY FEATURE (ESF) RESPONSE TIME	The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays, where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

1.1 Definitions (continued)

LEAKAGE

LEAKAGE shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator to the Secondary System (primary to secondary LEAKAGE);

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE;

c. Pressure Boundary LEAKAGE

LEAKAGE (except primary to secondary LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

MASTER RELAY TEST

A MASTER RELAY TEST shall consist of energizing all master relays in the channel required for channel OPERABILITY and verifying the OPERABILITY of each required master relay. The MASTER RELAY TEST shall include a continuity check of each associated required slave relay. The MASTER RELAY TEST may be performed by means of any series of sequential, overlapping or total steps.

MODE

A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

1.1 Definitions (continued)

OPERABLE - OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in Chapter 14, of the FSAR; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, the power operated relief valve (PORV) lift settings and the LTOP arming temperature associated with the Low Temperature Overpressurization Protection (LTOP) System, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3458 MWt through Cycle 13 for Unit 1 and through Cycle 11 for Unit 2. Starting with Cycles 14 and 12 of Units 1 and 2, respectively, RTP shall be 3612 MWt.

1.1 Definitions (continued)

REACTOR TRIP SYSTEM (RTS) RESPONSE TIME	The RTS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RTS trip setpoint at the channel sensor until loss of stationary gripper coil voltage. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM; and b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the hot zero power temperatures.
SLAVE RELAY TEST	A SLAVE RELAY TEST shall consist of energizing all slave relays in the channel required for channel OPERABILITY and verifying the OPERABILITY of each required slave relay. The SLAVE RELAY TEST shall include a continuity check of associated testable actuation devices. The SLAVE RELAY TEST may be performed by means of any series of sequential, overlapping or total steps.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

1.1 Definitions (continued)

TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	A TADOT shall consist of operating the trip actuating device and verifying the OPERABILITY of all devices in the channel required for trip actuating device OPERABILITY. The TADOT shall include adjustment, as necessary, of the trip actuating device so that it actuates at the required setpoint within the necessary accuracy. The TADOT may be performed by means of any series of sequential, overlapping or total channel steps.

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTIVITY CONDITION (k_{eff})	% RATED THERMAL POWER[a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Standby	< 0.99	NA	≥ 350
4	Hot Shutdown[b]	< 0.99	NA	$350 > T_{avg} > 200$
5	Cold Shutdown[b]	< 0.99	NA	≤ 200
6	Refueling[c]	NA	NA	NA

(a) Excluding decay heat.
(b) All reactor vessel head closure bolts fully tensioned.
(c) One or more reactor vessel head closure bolts less than fully tensioned.

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE

The purpose of this section is to explain the meaning of logical connectors.

Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TS are AND and OR. The physical arrangement of these connectors constitutes logical conventions with specific meanings.

BACKGROUND

Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentations of the logical connectors.

When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.

EXAMPLES

The following examples illustrate the use of logical connectors.

EXAMPLE 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example the logical connector AND is used to indicate that when in Condition A, both Required Actions A.1 and A.2 must be completed.

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Trip . . . OR A.2.1 Verify . . . AND A.2.2.1 Reduce . . . OR A.2.2.2 Perform . . . OR A.3 Align . . .	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2, and A.3 are alternative choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Actions may be chosen. If A.2 is chosen, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE

The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.

BACKGROUND

Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

Once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will <u>not</u> result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

However, when a <u>subsequent</u> train, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the <u>first</u> inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

1.3 Completion Times

DESCRIPTION (continued)

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extensions do not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each train, subsystem, component, or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition entry) or as a time modified by the phrase "from discovery . . ."

EXAMPLES

The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-1 (continued)

The Required Actions of Condition B are to be in MODE 3 within 6 hours AND in MODE 5 within 36 hours. A total of 6 hours is allowed for reaching MODE 3 and a total of 36 hours (not 42 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 3 hours, the time allowed for reaching MODE 5 is the next 33 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump inoperable.	A.1 Restore pump to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

When a pump is declared inoperable, Condition A is entered. If the pump is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable pump is restored to OPERABLE status after Condition B is entered, Condition A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

When a second pump is declared inoperable while the first pump is still inoperable, Condition A is not re-entered for the second pump. LCO 3.0.3 is entered, since the ACTIONS do not include a Condition for more than one inoperable pump. The Completion Time clock for Condition A does not stop after LCO 3.0.3 is entered, but continues to be tracked from the time Condition A was initially entered.

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has not expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition A.

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-2 (continued)

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked from the time the Condition A Completion Time expired.

On restoring one of the pumps to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first pump was declared inoperable. This Completion Time may be extended if the pump restored to OPERABLE status was the first inoperable pump. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second pump being inoperable for > 7 days.

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X train inoperable.	A.1 Restore Function X train to OPERABLE status.	7 days
B. One Function Y train inoperable.	B.1 Restore Function Y train to OPERABLE status.	72 hours
C. One Function X train inoperable. AND One Function Y train inoperable.	C.1 Restore Function X train to OPERABLE status. OR C.2 Restore Function Y train to OPERABLE status.	72 hours 72 hours

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X train and one Function Y train are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each train starting from the time each train was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second train was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected train was declared inoperable (i.e., initial entry into Condition A).

It is possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. However, doing so would be inconsistent with the basis of the Completion Times. Therefore, there shall be administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the Completion Times for those Conditions are not inappropriately extended.

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-4 (continued)

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent valve being inoperable for > 4 hours.

If the Completion Time of 4 hours (including the extension) expires while one or more valves are still inoperable, Condition B is entered.

EXAMPLE 1.3-5

ACTIONS

---NOTE---
Separate Condition entry is allowed for each inoperable valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

The Note above the ACTIONS Table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was applicable only to a specific Condition, the Note would appear in that Condition rather than at the top of the ACTIONS Table.

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-5 (continued)

declared inoperable, Condition A is entered and its Completion Time starts. If subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a "once per" Completion Time, which qualifies for the 25% extension, per SR 3.0.2, to each performance after the initial performance. The initial 8 hour interval of Required Action A.1 begins when Condition A is entered and the initial performance of Required Action A.1 must be complete within the first 8 hour interval. If Required Action A.1 is followed, and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-6 (continued)

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

IMMEDIATE COMPLETION TIME

When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR as well as certain Notes in the Surveillance column that modify performance requirements.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the stated Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is

1.4 Frequency

EXAMPLES

EXAMPLE 1.4-1 (continued)

not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Example 1.4-3), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, the Surveillance must be performed within the Frequency requirements of SR 3.0.2 prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of SR 3.0.4.

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the 25% extension allowed by SR 3.0.2. "Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
------------------------------NOTE------------------------------ Not required to be performed until 12 hours after ≥ 25% RTP. --	
Perform channel adjustment.	7 days

The interval continues, whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours with power ≥ 25% RTP.

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 In MODES 1 and 2, the departure from nucleate boiling ratio (DNBR) shall be maintained ≥ the 95/95 DNB criterion for the DNB correlation(s) specified in Section 5.6.5.

2.1.1.2 In MODES 1 and 2, the peak fuel centerline temperature shall be maintained < 4700°F.

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, or 5, restore compliance within 5 minutes.

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2 and LCO 3.0.7.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required unless otherwise stated.

LCO 3.0.3 When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 3 within 7 hours;

b. MODE 4 within 13 hours; and

c. MODE 5 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

LCO 3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time;

3.0 LCO APPLICABILITY

LCO 3.0.4 (continued)

b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate; exceptions to this Specification are stated in the individual Specifications, or

c. When an allowance is stated in the individual value, parameter, or other Specification.

This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

LCO 3.0.5 Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

LCO 3.0.6 When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, an evaluation shall be performed in accordance with Specification 5.5.15, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

3.0 LCO APPLICABILITY (continued)

LCO 3.0.7 Test Exception LCO 3.1.8, allows specified Technical Specification (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Test Exception LCOs is optional. When a Test Exception LCO is desired to be met but is not met, the ACTIONS of the Test Exception LCO shall be met. When a Test Exception LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall be made in accordance with the other applicable Specifications.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1 SRs shall be met during the MODES or other specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

SR 3.0.2 The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.

For Frequencies specified as "once," the above interval extension does not apply.

If a Completion Time requires periodic performance on a "once per . . ." basis, the above Frequency extension applies to each performance after the initial performance.

Exceptions to this Specification are stated in the individual Specifications.

SR 3.0.3 If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance.

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

3.0 SR APPLICABILITY (continued)

SR 3.0.4 Entry into a MODE or other specified condition in the Applicability of an LCO shall only be made when the LCO's Surveillances have been met within their specified Frequency, except as provided by SR 3.0.3. When an LCO is not met due to Surveillances not having been met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with LCO 3.0.4.

This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 SDM shall be within the limits provided in the COLR.

APPLICABILITY: MODE 2 with k_{eff} < 1.0,
MODES 3, 4, and 5

---NOTE---
While this LCO is not met, entry into MODE 5 from MODE 6 is not permitted.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify SDM to be within limits.	In accordance with the Surveillance Frequency Control Program.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Core Reactivity

LCO 3.1.2 The measured core reactivity shall be within ± 1% $\Delta k/k$ of predicted values.

APPLICABILITY: MODES 1 and 2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Measured core reactivity not within limit.	A.1 Re-evaluate core design and safety analysis, and determine that the reactor core is acceptable for continued operation. <u>AND</u> A.2 Establish appropriate operating restrictions and SRs.	7 days 7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.1.2.1	---------------------------------NOTE--------------------------------- The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading. --- Verify measured core reactivity is within ± 1% $\Delta k/k$ of predicted values.	Once prior to entering MODE 1 after each refueling <u>AND</u> ----------NOTE--------- Only required after 60 EFPD --------------------------- In accordance with the Surveillance Frequency Control Program.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Moderator Temperature Coefficient (MTC)

LCO 3.1.3 The MTC shall be maintained within the limits specified in the COLR. The maximum upper limit shall be that specified in Figure 3.1.3-1.

APPLICABILITY: MODE 1 and MODE 2 with $k_{eff} \geq 1.0$ for the upper MTC limit,
MODES 1, 2, and 3 for the lower MTC limit

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. MTC not within upper limit.	A.1 Establish administrative withdrawal limits for control banks to maintain MTC within limit.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2 with $k_{eff} < 1.0$.	6 hours
C. MTC not within lower limit.	C.1 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Verify MTC is within upper limit.	Once prior to entering MODE 1 after each refueling
SR 3.1.3.2	---------------------------------NOTES--------------------------------- 1. Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. 2. If the MTC is more negative than the 300 ppm Surveillance limit (not LCO limit) specified in the COLR, SR 3.1.3.2 shall be repeated once per 14 EFPD during the remainder of the fuel cycle. 3. SR 3.1.3.2 need not be repeated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of ≤ 60 ppm is less negative than the 60 ppm Surveillance limit specified in the COLR. --- Verify MTC is within lower limit.	Once each cycle

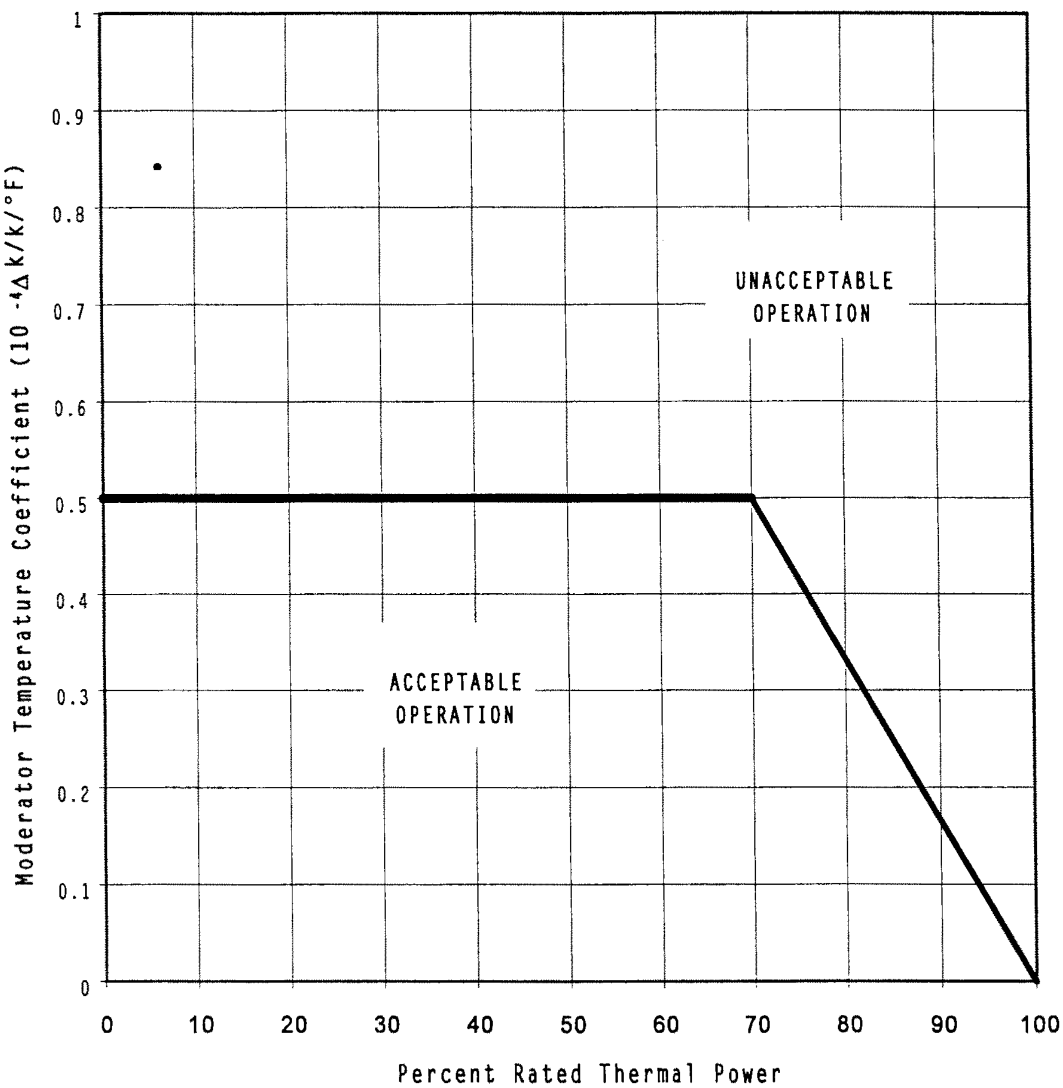

Figure 3.1.3-1 (page 1 of 1)
Moderator Temperature Coefficient vs. Power Level

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE.

AND

Individual indicated rod positions shall be within 12 steps of their group step counter demand position.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) inoperable.	A.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Be in MODE 3.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One rod not within alignment limits.	B.1 Restore rod to within alignment limits.	1 hour
	<u>OR</u>	
	B.2.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	<u>OR</u>	
	B.2.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	B.2.2 Reduce THERMAL POWER to ≤ 75% RTP.	2 hours
	<u>AND</u>	
	B.2.3 Verify SDM to be within the limits provided in the COLR.	Once per 12 hours
	<u>AND</u>	
	B.2.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	72 hours
	<u>AND</u>	
	B.2.5 Perform SR 3.2.2.1.	72 hours
	<u>AND</u>	
	B.2.6 Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	6 hours
D. More than one rod not within alignment limit.	D.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	<u>OR</u>	
	D.1.2 Initiate boration to restore required SDM to within limit.	1 hour
	<u>AND</u>	
	D.2 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify individual rod positions within alignment limit.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core ≥ 10 steps in either direction.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.3	Verify rod drop time of each rod, from the fully withdrawn position, is ≤ 2.7 seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. $T_{avg} \geq 500°F$; and b. All reactor coolant pumps operating.	Prior to reactor criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Shutdown Bank Insertion Limits

LCO 3.1.5 Each shutdown bank shall be within insertion limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with any control bank not fully inserted.

---NOTE---
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more shutdown banks not within limits.	A.1.1 Verify SDM to be within the limits provided in the COLR. <u>OR</u> A.1.2 Initiate boration to restore SDM to within limit. <u>AND</u> A.2 Restore shutdown banks to within limits.	1 hour 1 hour 2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each shutdown bank is within the limits specified in the COLR.	In accordance with the Surveillance Frequency Control Program.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Control Bank Insertion Limits

LCO 3.1.6 Control banks shall be within the insertion, sequence, and overlap limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with $k_{eff} \geq 1.0$.

-----------------------------NOTE-----------------------------
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control bank insertion limits not met.	A.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	OR	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	A.2 Restore control bank(s) to within limits.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Control bank sequence or overlap limits not met.	B.1.1 Verify SDM to be within the limits provided in the COLR.	1 hour
	OR	
	B.1.2 Initiate boration to restore SDM to within limit.	1 hour
	AND	
	B.2 Restore control bank sequence and overlap to within limits.	2 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify estimated critical control bank position is within the limits specified in the COLR.	Within 4 hours prior to achieving criticality
SR 3.1.6.2	Verify each control bank insertion is within the limits specified in the COLR.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.6.3	Verify sequence and overlap limits specified in the COLR are met for control banks not fully withdrawn from the core.	In accordance with the Surveillance Frequency Control Program.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Rod Position Indication

LCO 3.1.7 The Digital Rod Position Indication (DRPI) System and the Demand Position Indication System shall be OPERABLE

APPLICABILITY: MODES 1 and 2.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each inoperable rod position indicator and each demand position indicator per bank.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DRPI per group inoperable for one or more groups.	A.1 Verify the position of the rods with inoperable position indicators indirectly by using core power distribution measurement information.	Once per 8 hours
	<u>OR</u>	
	A.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. More than one DRPI per group inoperable.	B.1 Place the control rods under manual control.	Immediately
	<u>AND</u>	
	B.2 Monitor and record RCS T_{avg}.	Once per 1 hour
	<u>AND</u>	
	B.3 Verify the position of the rods with inoperable position indicators indirectly by using core power distribution measurement information.	Once per 8 hours
	<u>AND</u>	
	B.4 Restore inoperable position indicators to OPERABLE status such that a maximum of one DRPI per group is inoperable.	24 hours
C. One or more rods with inoperable DRPIs have been moved in excess of 24 steps in one direction since the last determination of the rod's position.	C.1 Verify the position of the rods with inoperable position indicators indirectly by using core power distribution measurement information.	4 hours
	<u>OR</u>	
	C.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One demand position indicator per bank inoperable for one or more banks.	D.1.1 Verify by administrative means all DRPIs for the affected banks are OPERABLE.	Once per 8 hours
	AND	
	D.1.2 Verify the most withdrawn rod and the least withdrawn rod of the affected banks are ≤ 12 steps apart.	Once per 8 hours
	OR	
	D.2 Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify each DRPI agrees within 12 steps of the group demand position for the full indicated range of rod travel.	Once prior to criticality after each removal of the reactor vessel head.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 PHYSICS TESTS Exceptions - MODE 2

LCO 3.1.8 During the performance of PHYSICS TESTS, the requirements of

LCO 3.1.3, "Moderator Temperature Coefficient (MTC)";
LCO 3.1.4, "Rod Group Alignment Limits";
LCO 3.1.5, "Shutdown Bank Insertion Limits";
LCO 3.1.6, "Control Bank Insertion Limits"; and
LCO 3.4.2, "RCS Minimum Temperature for Criticality"

may be suspended, provided:

a. RCS lowest operating loop average temperature is ≥ 541°F; and

b. SDM is within the limits provided in the COLR; and

c. THERMAL POWER is ≤ 5% RTP

APPLICABILITY: MODE 2 during PHYSICS TESTS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit.	15 minutes
	AND	
	A.2 Suspend PHYSICS TESTS exceptions.	1 hour
B. THERMAL POWER not within limit.	B.1 Open reactor trip breakers.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. RCS lowest operating loop average temperature not within limit.	C.1 Restore RCS lowest operating loop average temperature to within limit.	15 minutes
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Perform a CHANNEL OPERATIONAL TEST on power range and intermediate range channels per SR 3.3.1.7, SR 3.3.1.8, and Table 3.3.1-1.	Prior to initiation of PHYSICS TESTS
SR 3.1.8.2	Verify the RCS lowest operating loop average temperature is ≥ 541°F.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.8.3	Verify THERMAL POWER is ≤ 5% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.1.8.4	Verify SDM is within the limits provided in the COLR.	In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel ($F_Q(Z)$) (RAOC-W(Z) Methodology)

LCO 3.2.1 $F_Q(Z)$, as approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$, shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------NOTE--------------- Required Action A.4 shall be completed whenever this Condition is entered. ------------------------------------ $F_Q^C(Z)$ not within limit.	A.1 Reduce THERMAL POWER ≥ 1% RTP for each 1% $F_Q^C(Z)$ exceeds limit. <u>AND</u> A.2 Reduce Power Range Neutron Flux-- High trip setpoints ≥ 1% for each 1% $F_Q^C(Z)$ exceeds limit. <u>AND</u>	15 minutes after each $F_Q^C(Z)$ determination 72 hours after each $F_Q^C(Z)$ determination

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Reduce Overpower N-16 trip setpoints ≥ 1% for each 1% $F_Q^C(Z)$ exceeds limit.	72 hours after each $F_Q^C(Z)$ determination
	AND	
	A.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action A.1

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------------NOTE-------------- Required Action B.4 shall be completed whenever this Condtion is entered. ------------------------------------ $F_Q^W(Z)$ not within limits.	B.1 Reduce AFD limits ≥ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	4 hours
	AND	
	B.2 Reduce Power Range Neutron Flux--High trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	AND	
	B.3 Reduce Overpower N-16 trip setpoints ≥ 1% for each 1% that the maximum allowable power of the AFD limits is reduced.	72 hours
	AND	
	B.4 Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the maximum allowable power of the AFD limits.
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

--NOTE--
During power escalation following shutdown, THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution measurement is obtained.

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify $F_Q^C(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> Once within 24 hours after achieving equilibrium conditions after exceeding, by ≥ 20% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified <u>AND</u> In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.1.2	---------------------------------NOTE--------------------------------- If $F^C_Q(Z)$ measurements indicate maximum over z $\left[\frac{F^C_Q(Z)}{K(Z)}\right]$ has increased since the previous evaluation of $F^C_Q(Z)$: a. Increase $F^W_Q(Z)$ by an appropriate factor specified in the COLR and reverify $F^W_Q(Z)$ is within limits; or b. Repeat SR 3.2.1.2 once per 7 EFPD until either a. above is met or two successive power distribution measurements indicate maximum over z $\left[\frac{F^C_Q(Z)}{K(Z)}\right]$ has not increased. ---	
	Verify $F^W_Q(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u>

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.2 (continued)	Once within 24 hours after achieving equilibrium conditions after exceeding, by ≥ 20% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified <u>AND</u> In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

LCO 3.2.2 $F^N_{\Delta H}$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Required Actions A.2 and A.3 must be completed whenever Condition A is entered. ------------------------------------ $F^N_{\Delta H}$ not within limit.	A.1.1 Restore $F^N_{\Delta H}$ to within limit.	4 hours
	<u>OR</u>	
	A.1.2.1 Reduce THERMAL POWER to < 50% RTP.	4 hours
	<u>AND</u>	
	A.1.2.2 Reduce Power Range Neutron Flux- High trip setpoints to ≤ 55% RTP.	72 hours
	<u>AND</u>	
	A.2 Perform SR 3.2.2.1.	24 hours
	<u>AND</u>	

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 --------------------NOTE--------------------- THERMAL POWER does not have to be reduced to comply with this Required Action. --- Perform SR 3.2.2.1.	 Prior to THERMAL POWER exceeding 50% RTP <u>AND</u> Prior to THERMAL POWER exceeding 75% RTP <u>AND</u> 24 hours after THERMAL POWER reaching ≥ 95% RTP
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

--NOTE--
During power escalation following shutdown, THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution measurement is obtained.

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Relaxed Axial Offset Control (RAOC) Methodology)

LCO 3.2.3 The AFD in % flux difference units shall be maintained within the limits specified in the COLR.

--NOTE--
The AFD shall be considered outside limits when two or more OPERABLE excore channels indicate AFD to be outside limits.

APPLICABILITY: MODE 1 with THERMAL POWER $\geq$ 50% RTP

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. AFD not within limits.	A.1 Restore THERMAL POWER to < 50% RTP.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD is within limits for each OPERABLE excore channel.	In accordance with the Surveillance Frequency Control Program.

3.2 POWER DISTRIBUTION LIMITS

3.2.4 QUADRANT POWER TILT RATIO (QPTR)

LCO 3.2.4 The QPTR shall be ≤ 1.02.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RTP

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. QPTR not within limit.	A.1 Reduce THERMAL POWER ≥ 3% from RTP for each 1% of QPTR >1.00.	2 hours after each QPTR determination
	<u>AND</u>	
	A.2 Determine QPTR.	Once per 12 hours
	<u>AND</u>	
	A.3 Perform SR 3.2.1.1, SR 3.2.1.2 and SR 3.2.2.1.	24 hours after achieving equilibrium conditions from a THERMAL POWER reduction per Required Action A.1 <u>AND</u> Once per 7 days thereafter
	<u>AND</u>	

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.4 Reevaluate safety analyses and confirm results remain valid for duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>	
	A.5 -------------------NOTES-------------------- 1. Perform Required Action A.5 only after Required Action A.4 is completed. 2. Required Action A.6 shall be completed whenever Required Action A.5 is performed. --- Normalize excore detectors to restore QPTR to within limit.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>	
	A.6 ---------------------NOTE-------------------- Perform Required Action A.6 only after Required Action A.5 is completed. --- Perform SR 3.2.1.1, SR 3.2.1.2 and SR 3.2.2.1.	Within 24 hours after achieving equilibrium conditions at RTP not to exceed 48 hours after increasing THERMAL POWER above the limit of Required Actions A.1
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to ≤ 50% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.2.4.1	-----NOTES----- 1. With input from one Power Range Neutron Flux channel inoperable and THERMAL POWER ≤ 75% RTP, the remaining three power range channels can be used for calculating QPTR. 2. SR 3.2.4.2 may be performed in lieu of this Surveillance. ---------- Verify QPTR is within limit by calculation.	In accordance with the Surveillance Frequency Control Program.
SR 3.2.4.2	-----NOTE----- Not required to be performed until 12 hours after input from one or more Power Range Neutron Flux channels are inoperable with THERMAL POWER > 75% RTP. ---------- Verify QPTR is within limit using the core power distribution measurement information.	In accordance with the Surveillance Frequency Control Program.

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1

ACTIONS

--NOTE--
Separate Condition entry is allowed for each Function.

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CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train(s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1 Restore channel to OPERABLE status.	48 hours
	<u>OR</u>	
	B.2 Be in MODE 3.	54 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. --------------NOTE-------------- While this LCO is not met for Function 19, 20, or 21, in MODE 5, making the Rod Control System capable of rod withdrawal is not permitted. ------------------------------------		
One channel or train inoperable.	C.1 Restore channel or train to OPERABLE status.	48 hours
	<u>OR</u>	
	C.2.1 Initiate action to fully insert all rods.	48 hours
	<u>AND</u>	
	C.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One Power Range Neutron Flux - High channel inoperable.	----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing and setpoint adjustment. --	
	D.1.1 ------------------NOTE------------------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ---	
	Perform SR 3.2.4.2.	12 hours from discovery of THERMAL POWER > 75% RTP <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>	
	D.1.2 Place channel in trip.	72 hours
	<u>OR</u>	
	D.2 Be in MODE 3	78 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One channel inoperable.	----------------------NOTE---------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	E.1 Place channel in trip.	72 hours
	<u>OR</u>	
	E.2 Be in MODE 3.	78 hours
F. One Intermediate Range Neutron Flux channel inoperable.	F.1 Reduce THERMAL POWER to < P-6.	24 hours
	<u>OR</u>	
	F.2 Increase THERMAL POWER to > P-10.	24 hours
G. Two Intermediate Range Neutron Flux channels inoperable.	G.1 -----------------NOTE--------------------- Limited boron concentration changes associated with RCS inventory control or limited plant temperature changes are allowed. -- Suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
	G.2 Reduce THERMAL POWER to < P-6.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Not used.		
I. One Source Range Neutron Flux channel inoperable.	------------------------NOTE----------------------- Limited boron concentration changes associated with RCS inventory control or limited plant temperature changes are allowed. --	
	I.1 Suspend operations involving positive reactivity additions.	Immediately
J. Two Source Range Neutron Flux channels inoperable.	J.1 Open reactor trip breakers (RTBs).	Immediately
K. One Source Range Neutron Flux channel inoperable.	K.1 Restore channel to OPERABLE status.	48 hours
	<u>OR</u>	
	K.2.1 Initiate action to fully insert all rods.	48 hours
	<u>AND</u>	
	K.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours
L. Not used.		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. One channel inoperable.	------------------------NOTE----------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	M.1 Place channel in trip.	72 hours
	<u>OR</u>	
	M.2 Reduce THERMAL POWER to < P-7.	78 hours
N. Not used.		
O. One Low Fluid Oil pressure Turbine Trip channel inoperable.	------------------------NOTE----------------------- One channel may be bypassed for up to 12 hours for surveillance testing. --	
	O.1 Place channel in trip.	72 hours
	<u>OR</u>	
	O.2 Reduce THERMAL POWER to < P-9.	76 hours
P. One or more Turbine Stop Valve Closure Turbine Trip channel(s) inoperable.	P.1 Place channel(s) in trip.	72 hours
	<u>OR</u>	
	P.2 Reduce THERMAL POWER to < P-9.	76 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
Q. One train inoperable.	------------------------NOTE----------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --	
	Q.1 Restore train to OPERABLE status.	24 hours
	<u>OR</u>	
	Q.2 Be in MODE 3.	30 hours
R. One RTB train inoperable.	------------------------NOTE----------------------- One train may be bypassed for up to 4 hours for surveillance testing or maintenance, provided the other train is OPERABLE. --	
	R.1 Restore train to OPERABLE status.	24 hours
	<u>OR</u>	
	R.2 Be in MODE 3.	30 hours
S. One or more required channel(s) inoperable.	S.1 Verify interlock is in required state for existing unit conditions.	1 hour
	<u>OR</u>	
	S.2 Be in MODE 3.	7 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
T. One or more required channel(s) inoperable.	T.1 Verify interlock is in required state for existing unit conditions. <u>OR</u> T.2 Be in MODE 2.	1 hour 7 hours
U. One trip mechanism inoperable for one RTB.	U.1 Restore inoperable trip mechanism to OPERABLE status. <u>OR</u> U.2 Be in MODE 3.	48 hours 54 hours
V. Not used.		

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.2	-----------------------------------NOTE----------------------------------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 15% RTP. ---	
	Compare results of calorimetric heat balance calculation to NIS Power Range channel and N-16 Power Monitor channel outputs. Adjust NIS Power Range channel outputs if calorimetric heat balance calculation exceeds NIS Power Range channel outputs by more than +2% RTP. Adjust N-16 Power Monitor channel outputs if calorimetric heat balance calculation exceeds N-16 Power Monitor channel outputs by more than +2% RTP.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.3	-----------------------------------NOTE----------------------------------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. ---	
	Compare results of the core power distribution measurements to Nuclear Instrumentation System (NIS) AFD. Adjust NIS channel if absolute difference is ≥ 3%.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.4	-----------------------------------NOTE----------------------------------- This Surveillance must be performed on the reactor trip bypass breaker for the local manual shunt trip only prior to placing the bypass breaker in service. ---	
	Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.6	----------NOTE---------- Not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 75% RTP. -------------------- Calibrate excore channels to agree with core power distribution measurements.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.7	----------NOTES---------- 1. Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. 2. Source range instrumentation shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. -------------------- Perform COT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	------------------------------NOTE------------------------------ This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. --- Perform COT.	---------NOTE---------- Only required when not performed within the previous Frequency specified in the SFCP. --------------------------- Prior to reactor startup <u>AND</u> 12 hours after reducing power below P-10 for power and intermediate instrumentation <u>AND</u> Four hours after reducing power below P-6 for source range instrumentation <u>AND</u> In accordance with the Surveillance Frequency Control Program thereafter

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.9	----------NOTE---------- Verification of setpoint is not required. ------------------------------ Perform TADOT.	 In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.10	----------NOTES---------- 1. N-16 detectors are excluded from CHANNEL CALIBRATION. 2. This Surveillance shall include verification that the time constants are adjusted to the prescribed values. 3. Prior to entry into MODES 2 or 1, N-16 detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER ≥ 90% RTP. ------------------------------ Perform CHANNEL CALIBRATION.	 In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.11	-----NOTES----- 1. Neutron detectors are excluded from CHANNEL CALIBRATION. 2. This Surveillance shall include verification that the time constants are adjusted to the prescribed values. 3. Prior to entry into MODES 2 or 1, power and intermediate range detector plateau verification is not required to be performed until 72 hours after achieving equilibrium conditions with THERMAL POWER $\geq$ 90% RTP. ---------- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.12	Not used.	
SR 3.3.1.13	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.1.14	-----NOTE----- Verification of setpoint is not required. ---------- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.15	-----------------------------------NOTE----------------------------------- Verification of setpoint is not required. -- Perform TADOT.	 Prior to exceeding the P-9 interlock whenever the unit has been in MODE 3, if not performed in the previous Frequency specified in the SFCP
SR 3.3.1.16	-----------------------------------NOTE----------------------------------- Neutron and N-16 detectors are excluded from response time testing. -- Verify RTS RESPONSE TIMES are within limits.	 In accordance with the Surveillance Frequency Control Program.

Table 3.3.1-1 (page 1 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA
	3[b], 4[b], 5[b]	2	C	SR 3.3.1.14	NA
2. Power Range Neutron Flux					
a. High	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ 109.6% RTP[q][r]
b. Low	1[c], 2	4	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11 SR 3.3.1.16	≤ 25.6% RTP[q][r]
3. Power Range Neutron Flux Rate High Positive Rate	1,2	4	E	SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ 6.3% RTP with time constant ≥ 2 sec
4. Intermediate Range Neutron Flux	1[c], 2[d]	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 31.5% RTP

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.
(c) Below the P-10 (Power Range Neutron Flux) interlock.
(d) Above the P-6 (Intermediate Range Neutron Flux) interlock.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 2 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
5. Source Range Neutron Flux	2[e]	2	I,J	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 1.4 E5 cps
	3[b], 4[b], 5[b]	2	J,K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≤ 1.4 E5 cps
6. Overtemperature N-16	1,2	4	E	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	Refer to Note 1[q][r]
7. Overpower N-16	1,2	4	E	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≤ 112.8% RTP [q][r]
8. Pressurizer Pressure					
a. Low	1[g]	4	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 1863.6 psig (Unit 1) ≥ 1865.2 psig (Unit 2)
b. High	1,2	4	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≤ 2400.8 psig (Unit 1) ≤ 2401.4 psig (Unit 2)

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Control System capable of rod withdrawal or one or more rods not fully inserted.
(e) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(g) Above the P-7 (Low Power Reactor Trips Block) interlock.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 3 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
9. Pressurizer Water Level - High	1[(g)]	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 93.9% of instrument span
10. Reactor Coolant Flow - Low	1[(g)]	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 88.6% of indicated loop flow (Unit 1) ≥ 88.8% of indicated loop flow (Unit 2)
11. Not Used					
12. Undervoltage RCPs	1[(g)]	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 4753 V
13. Underfrequency RCPs	1[(g)]	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 57.06 Hz
14. Steam Generator (SG) Water Level Low-Low [(l)]	1, 2	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 37.5% of narrow range instrument span (Unit 1) [(q)(r)] ≥ 34.9% of narrow range instrument span (Unit 2)[(q)(r)]
15. Not Used.					

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(g) Above the P-7 (Low Power Reactor Trips Block) interlock.
(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.1-1 (page 4 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
16. Turbine Trip					
a. Low Fluid Oil Pressure	1[(j)]	3	O	SR 3.3.1.10 SR 3.3.1.15	≥ 46.6 psig
b. Turbine Stop Valve Closure	1[(j)]	4	P	SR 3.3.1.10 SR 3.3.1.15	≥ 1% open
17. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	Q	SR 3.3.1.14	NA
18. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2[(e)]	2	S	SR 3.3.1.11 SR 3.3.1.13	≥ 6E-11 amp
b. Low Power Reactor Trips Block, P-7	1	1 per train	T	SR 3.3.1.5	NA
c. Power Range Neutron Flux, P-8	1	4	T	SR 3.3.1.11 SR 3.3.1.13	≤ 50.7% RTP
d. Power Range Neutron Flux, P-9	1	4	T	SR 3.3.1.11 SR 3.3.1.13	≤ 52.7% RTP
e. Power Range Neutron Flux, P-10	1,2	4	S	SR 3.3.1.11 SR 3.3.1.13	≥ 7.3% RTP and ≤ 12.7% RTP
f. Turbine First Stage Pressure, P-13	1	2	T	SR 3.3.1.10 SR 3.3.1.13	≤ 12.7% turbine power
19. Reactor Trip Breakers(RTBs)[(k)]	1,2	2 trains	R	SR 3.3.1.4	NA
	3[(b)], 4[(b)], 5[(b)]	2 trains	C	SR 3.3.1.4	NA

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Contol System capable of rod withdrawal or one or more rods not fully inserted.
(e) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(j) Above the P-9 (Power Range Neutron Flux) interlock.
(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 5 of 6)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
20. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms[(k)]	1,2	1 each per RTB	U	SR 3.3.1.4	NA
	3[(b)], 4[(b)], 5[(b)]	1 each per RTB	C	SR 3.3.1.4	NA
21. Automatic Trip Logic	1,2	2 trains	Q	SR 3.3.1.5	NA
	3[(b)], 4[(b)], 5[(b)]	2 trains	C	SR 3.3.1.5	NA

(a) The Allowable Value defines the limiting safety system setting except for Trip Functions 2a, 2b, 6, 7, and 14 (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) With Rod Contol System capable of rod withdrawal or one or more rods not fully inserted.
(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 6 of 6)
Reactor Trip System Instrumentation

Note 1: Overtemperature N-16

The Overtemperature N-16 Function Allowable Values shall not exceed the following setpoint by more than 0.5% N-16 span for N-16 input, 0.5% T_{cold} span for T_{cold} input, 0.5% pressure span for pressure input, and 0.5% Δq span for Δq input.

$$Q_{setpoint} = K_1 - K_2\left[\frac{(1+\tau_1 S)}{(1+\tau_2 S)}T_c - T_c^{\circ}\right] + K_3(P - P^1) - f_1(\Delta q)$$

Where:

$Q_{setpoint}$	=	Overtemperature N-16 trip setpoint
K_1	=	*
K_2	=	*/°F
K_3	=	*/psig
T_C	=	Measured cold leg temperature, °F
T_c°	=	Indicated reference T_C at RATED THERMAL POWER, *°F
P	=	Measured pressurizer pressure, psig
P^1	≥	* psig (Nominal RCS operating pressure)
s	=	the Laplace transform operator, sec^{-1}.
τ_1,τ_2	=	Time constants utilized in lead-lag controller for T_c, $\tau_1 \geq$ * sec, and $\tau_2 \leq$ * sec
$f_1(\Delta q)$	=	*$\{(q_t - q_b)$ + *%} when $(q_t - q_b) \leq$ *% RTP 0% when *% RTP < $(q_t - q_b)$ < *% RTP *$\{(q_t - q_b)$ - *%} when $(q_t - q_b) \geq$ *% RTP

* as specified in the COLR

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status.	48 hours
	<u>OR</u>	
	B.2.1 Be in MODE 3.	54 hours
	<u>AND</u>	
	B.2.2 Be in MODE 5.	84 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	-----------------------NOTE------------------------ One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---	
	C.1 Restore train to OPERABLE status.	24 hours
	<u>OR</u>	
	C.2.1 Be in MODE 3.	30 hours
	<u>AND</u>	
	C.2.2 Be in MODE 5.	60 hours
D. One channel inoperable.	-----------------------NOTE------------------------ One channel may be bypassed for up to 12 hours for surveillance testing. ---	
	D.1 Place channel in trip.	72 hours
	<u>OR</u>	
	D.2.1 Be in MODE 3.	78 hours
	<u>AND</u>	
	D.2.2 Be in MODE 4.	84 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One Containment Pressure channel inoperable.	-----------------------NOTE------------------------ One channel may be bypassed for up to 12 hours for surveillance testing. ---	
	E.1 Place channel in bypass.	72 hours
	<u>OR</u>	
	E.2.1 Be in MODE 3.	78 hours
	<u>AND</u>	
	E.2.2 Be in MODE 4.	84 hours
F. One channel or train inoperable.	F.1 Restore channel or train to OPERABLE status.	48 hours
	<u>OR</u>	
	F.2.1 Be in MODE 3.	54 hours
	<u>AND</u>	
	F.2.2 Be in MODE 4.	60 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One train inoperable.	----------------------NOTE---------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --	
	G.1 Restore train to OPERABLE status.	24 hours
	OR	
	G.2.1 Be in MODE 3.	30 hours
	AND	
	G.2.2 Be in MODE 4.	36 hours
H. One train inoperable.	----------------------NOTE---------------------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. --	
	H.1 Restore train to OPERABLE status.	24 hours
	OR	
	H.2 Be in MODE 3.	30 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. One channel inoperable.	-----------------------NOTE------------------------ One channel may be bypassed for up to 12 hours for surveillance testing. ---	
	I.1 Place channel in trip.	72 hours
	<u>OR</u>	
	I.2 Be in MODE 3.	78 hours
J. One Main Feedwater Pump trip channel inoperable.	J.1 Place channel in trip.	6 hours
	<u>OR</u>	
	J.2 Be in MODE 3.	12 hours
K. One channel inoperable.	-----------------------NOTE------------------------ One channel may be bypassed for up to 12 hours for surveillance testing. ---	
	K.1 Place channel in bypass.	72 hours
	<u>OR</u>	
	K.2.1 Be in MODE 3.	78 hours
	<u>AND</u>	
	K.2.2 Be in MODE 5.	108 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One or more required channel(s) inoperable.	L.1 Verify interlock is in required state for existing unit condition.	1 hour
	<u>OR</u>	
	L.2.1 Be in MODE 3.	7 hours
	<u>AND</u>	
	L.2.2 Be in MODE 4.	13 hours

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.3	Not Used.	

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.4	Perform MASTER RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.5	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.6	Perform SLAVE RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.7	--------------------------------NOTES-------------------------------- 1. Verification of relay setpoints not required. 2. Actuation of final devices not included. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.8	--------------------------------NOTE-------------------------------- Verification of setpoint not required for manual initiation functions. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.2.9	------------------------------NOTE------------------------------ This Surveillance shall include verification that the time constants are adjusted to the prescribed values. -- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.10	------------------------------NOTE------------------------------ Not required to be performed for the turbine driven AFW pump until 24 hours after SG pressure is ≥ 532 psig. -- Verify ESF RESPONSE TIMES are within limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.2.11	------------------------------NOTE------------------------------ Verification of setpoint not required. -- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.2-1 (page 1 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
1. Safety Injection					
a. Manual Initiation	1, 2, 3, 4	2	B	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Containment Pressure -- High 1	1, 2, 3	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 3.8 psig
d. Pressurizer Pressure -- Low	1, 2, 3[b]	4	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 1803.6 psig
e. Steam Line Pressure Low	1, 2, 3[b]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 594.0 psig[c] (Unit 1) ≥ 578.4 psig[c] (Unit 2)
2. Containment Spray					
a. Manual Initiation	1, 2, 3, 4	2 per train, 2 trains	B	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Containment Pressure High -- 3	1, 2, 3	4	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 18.8 psig

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) Above the P-11 (Pressurizer Pressure) interlock and below P-11, unless the Function is blocked.
(c) Time constants used in the lead/lag controller are $T_1 \geq 10$ seconds and $T_2 \leq 5$ seconds.

Table 3.3.2-1 (page 2 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
3. Containment Isolation					
a. Phase A Isolation					
(1) Manual Initiation	1, 2, 3, 4	2	B	SR 3.3.2.8	NA
(2) Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
(3) Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
b. Phase B Isolation					
(1) Manual Initiation	1, 2, 3, 4	2 per train, 2 trains	B	SR 3.3.2.8	NA
(2) Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
(3) Containment Pressure High -- 3	1, 2, 3	4	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9	≤ 18.8 psig

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

Table 3.3.2-1 (page 3 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
4. Steam Line Isolation					
a. Manual Initiation	1, 2[(i)], 3[(i)]	2	F	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays	1, 2[(i)], 3[(i)]	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Containment Pressure -- High 2	1, 2[(i)], 3[(i)]	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 6.8 psig
d. Steam Line Pressure					
(1) Low	1, 2[(i)], 3[(b)(i)]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 594.0 psig[(c)] (Unit 1) ≥ 578.4 psig[(c)] (Unit 2)
(2) Negative Rate -- High	3[(g)(i)]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 178.7 psi[(h)]

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(b) Above the P-11 (Pressurizer Pressure) Interlock and below P-11, unless the Function is blocked.
(c) Time constants used in the lead/lag controller are $T_1 \geq 10$ seconds and $T_2 \leq 5$ seconds.
(g) Below the P-11 (Pressurizer Pressure) Interlock; however, may be blocked below P-11 when safety injection on steam line pressure-low is not blocked.
(h) Time constant utilized in the rate/lag controller is ≥ 50 seconds.
(i) Except when all MSIVs and their associated upstream drip pot isolation valves are closed and deactivated.

Table 3.3.2-1 (page 4 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
5. Turbine Trip and Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	1, 2(j)	2 trains	H	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. SG Water Level -- High High (P-14)	1, 2(j)	3 per SG(p)	I	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤84.5% of narrow range span (Unit 1) (q)(r) ≤82.0% of narrow range span (Unit 2) (q)(r)
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.
(j) Except when all MFIVs and associated bypass valves are closed and de-activated or isolated by a closed manual valve.
(p) A channel selected for use as an input to the SG water level controller must be declared inoperable.
(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.2-1 (page 5 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays (Solid State Protection System)	1, 2, 3	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. Not Used.					
c. SG Water Level Low-Low	1, 2, 3	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥37.5% of narrow range span (Unit 1) [q][r] ≥34.9% of narrow range span (Unit 2) [q][r]
d. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
e. Loss of Offsite Power	1, 2, 3	1 per train	F	SR 3.3.2.7 SR 3.3.2.9 SR 3.3.2.10	NA
f. Not Used.					
g. Trip of all Main Feedwater Pumps	1, 2	2 per AFW pump	J	SR 3.3.2.8	NA
h. Not Used.					

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

(q) If the as-found channel setpoint is conservative with respect to the Allowable Value but outside its predefined as-found acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(r) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Nominal Trip Setpoint, or a value that is more conservative than the Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoint, the methodology used to determine the as-found tolerance and the methodology used to determine the as-left tolerance shall be specified in the Technical Specification Bases.

Table 3.3.2-1 (page 6 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
7. Automatic Switchover to Containment Sump					
a. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
b. Refueling Water Storage Tank (RWST) Level - Low Low	1, 2, 3, 4	4	K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 31.9% instrument span
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
8. ESFAS Interlocks					
a. Reactor Trip, P-4	1, 2, 3	1 per train, 2 trains	F	SR 3.3.2.11	NA
b. Pressurizer Pressure, P-11	1, 2, 3	3	L	SR 3.3.2.5 SR 3.3.2.9	≤ 1975.2 psig (Unit 1) ≤ 1976.4 psig (Unit 2)

(a) The Allowable Value defines the limiting safety system except for functions 5b and 6c (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions). See the Bases for the Nominal Trip Setpoints.

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3

ACTIONS

--NOTE--
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.8.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more Functions with two required channels inoperable. OR One required T_{hot} channel and one required Core Exit Temperature channel inoperable. OR One required T_{cold} channel and one required Steam Line Pressure channel for the associated loop inoperable.	C.1 Restore one channel to OPERABLE status.	7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.3-1.	E.1 Be in MODE 3. AND E.2 Be in MODE 4.	6 hours 12 hours
F. As required by Required Action D.1 and referenced in Table 3.3.3-1.	F.1 Initiate action in accordance with Specification 5.6.8.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---
SR 3.3.3.1 and SR 3.3.3.3 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.3.2	Deleted	
SR 3.3.3.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITION REFERENCED FROM REQUIRED ACTION D.1
1. Refueling Water Storage Tank Level	2	E
2. Subcooling Monitors	2	E
3. Reactor Coolant System (RCS) Hot Leg Temperature (Wide Range) (T_{hot})	1 per loop	E
4. RCS Cold Leg Temperature (Wide Range) (T_{cold})	1 per loop	E
5. RCS Pressure (Wide Range)	2	E
6. Reactor Vessel Water Level	2[(a)]	F
7. Containment Sump Water Level (Wide Range)	2	E
8. Containment Pressure (Intermediate Range)	2	E
9. Steam Line Pressure	2 per steam line	E
10. Containment Area Radiation (High Range)	2	F
11. Deleted		
12. Pressurizer Water Level	2	E
13. Steam Generator Water Level (Narrow Range)	2 per steam generator	E
14. Condensate Storage Tank Level	2	E
15. Core Exit Temperature - Quadrant 1	2[(c)]	E
16. Core Exit Temperature - Quadrant 2	2[(c)]	E
17. Core Exit Temperature - Quadrant 3	2[(c)]	E
18. Core Exit Temperature - Quadrant 4	2[(c)]	E
19. Auxiliary Feedwater Flow		
a. AFW Flow	2 per steam generator	E
<u>OR</u>		
b. AFW Flow and Steam Generator Water Level (Wide Range)	1 each per steam generator	E

(a) A channel is eight sensors in a probe. A channel is OPERABLE if four or more sensors, one or more in the upper section and three or more in the lower section, are OPERABLE.
(b) Deleted
(c) A channel consists of two core exit thermocouples (CETs).

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown System

LCO 3.3.4 The Remote Shutdown System Functions in Table 3.3.4-1 and the required hot shutdown panel (HSP) controls shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function and required HSP control.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Functions inoperable. OR One or more required HSP controls inoperable.	A.1 Restore required Function and required HSP controls to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.2	Verify each required HSP power and control circuit and transfer switch is capable of performing the intended function.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.4.3	-----------------------------------NOTE----------------------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION for each required instrumentation channel.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.4-1 (page 1 of 1)
Remote Shutdown System Functions

FUNCTION	REQUIRED CHANNELS
1. Neutron Flux Monitors	1
2. Pressurizer Pressure	1
3. RCS Hot Leg Temperature	1 per loop
4. RCS Cold Leg Temperature	1 per loop
5. Condensate Storage Tank Level	1
6. SG Pressure	1 per SG
7. SG Level	1 per SG
8. AFW Flow	1 per SG
9. Pressurizer Level	1
10. Charging Pump to CVCS Charging and RCP Seals Flow Indication	1

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.5 The Loss of Power Diesel Generator Start Instrumentation for each Function in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

--NOTE--
Not applicable for 6.9 kV Preferred Offsite Source Undervoltage function when associated source breaker is open.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE------------- Not applicable to Automatic Actuation Logic and Actuation Relays Function ------------------------------------ One or more Functions with one channel per bus inoperable.	A.1 Place channel in trip.	6 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two channels per bus for the Preferred offsite source bus undervoltage function inoperable.	B.1 Restore one channel per bus to OPERABLE status.	1 hour
	<u>OR</u>	
	B.2.1 Declare the Preferred offsite source inoperable.	1 hour
	<u>AND</u>	
	B.2.2 Open associated Preferred offsite source bus breaker.	6 hours
C. Two channels per bus for the Alternate offsite source bus undervoltage function inoperable.	C.1 Restore one channel per bus to OPERABLE status.	1 hour
	<u>OR</u>	
	C.2.1 Declare the Alternate offsite source inoperable.	1 hour
	<u>AND</u>	
	C.2.2 Open associated Alternate offsite source bus breaker.	6 hours
D. Two channels per bus for the 6.9 kV bus loss of voltage function inoperable.	D.1 Restore one channel per bus to OPERABLE status.	1 hour
	<u>OR</u>	
	D.2 Declare the affected A.C. emergency buses inoperable.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two channels per bus for one or more degraded voltage or low grid undervoltage function inoperable	E.1 Restore one channel per bus to OPERABLE status. <u>OR</u> E.2.1 Declare both offsite power source buses inoperable. <u>AND</u> E.2.2 Open offsite power source breakers to the associated buses.	1 hour 1 hour 6 hours
F. One or more Automatic Actuation Logic and Actuation Relays trains inoperable.	F.1 Restore train(s) to OPERABLE status.	1 hour
G. Required Action and associated Completion Time not met.	G.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.3.5.1	Perform ACTUATION LOGIC TEST.	Prior to entering MODE 4 when in MODE 5 for ≥ 72 hours and if not performed in the previous Frequency specified in the SFCP
SR 3.3.5.2	-----------------------------------NOTE----------------------------------- Setpoint verification is not applicable. -- Perform TADOT.	Prior to entering MODE 4 when in MODE 5 for ≥ 72 hours and if not performed in the previous Frequency specified in the SFCP
SR 3.3.5.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.5.4	Verify LOP DG start ESF RESPONSE TIMES are within limits.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.5-1 (page 1 of 1)
Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Automatic Actuation Logic and Actuation Relays	2 trains	3.3.5.1	NA
2. Preferred offsite source bus undervoltage	2 per bus	3.3.5.2 3.3.5.3	≤ 5580 V and ≥ 5040 V
3. Alternate offsite source bus undervoltage	2 per bus	3.3.5.2 3.3.5.3	≤ 5580 V and ≥ 5040 V
4. 6.9 kv Class 1E bus undervoltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≤ 2115 V
5. 6.9 kv Class 1E bus degraded voltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 6024 V
6. 480 V Class 1E bus low grid undervoltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 439 V
7. 480 V Class 1E bus degraded voltage	2 per bus	3.3.5.2 3.3.5.3 3.3.5.4	≥ 439 V

3.3 INSTRUMENTATION

3.3.6 Containment Ventilation Isolation Instrumentation

LCO 3.3.6 The Containment Ventilation Isolation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6-1

ACTIONS

--NOTE--
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One radiation monitoring channel inoperable.	A.1 Restore the affected channel to OPERABLE status.	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------------NOTE-------------- Only applicable in MODE 1, 2, 3, or 4. ------------------------------------	-----------------------NOTE------------------------ For Required Action and associated Completion Time of Condition A not met, the containment pressure relief valves may be opened in compliance with the gaseous effluent monitoring instrumentation requirements in Part I of the ODCM. --	
One or more Automatic Actuation Logic and Actuation Relays trains inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A not met.	B.1 Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves," for containment ventilation isolation valves made inoperable by isolation instrumentation.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. --------------NOTE------------ Only applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. ---------------------------------- Required Action and associated Completion Time for Condition A not met.	----------------------NOTE----------------------- The containment pressure relief valves may be opened in compliance with the gaseous effluent monitoring instrumentation requirements in Part I of the ODCM. -- C.1 Place and maintain containment ventilation valves in closed position. <u>OR</u> C.2 Enter applicable Conditions and Required Actions of LCO 3.9.4, "Containment Penetrations," for containment ventilation isolation valves made inoperable by isolation instrumentation.	 Immediately Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Ventilation Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.2	Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.3	Perform MASTER RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.4	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.5	Perform SLAVE RELAY TEST.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.6.6	Not Used.	
SR 3.3.6.7	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.6-1 (page 1 of 1)
Containment Ventilation Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	1, 2, 3, 4	Refer to LCO 3.3.2 "ESFAS Instrumentation," Functions 2.a and 3.a.1, respectively for all initiation functions and requirements.		
2. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	SR 3.3.6.2 SR 3.3.6.3 SR 3.3.6.5	NA
3. Containment Radiation				
a. Gaseous	1, 2, 3, 4, (b), (c)	1	SR 3.3.6.1 SR 3.3.6.4 SR 3.3.6.7	(a)
4. Containment Isolation - Phase A	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 3.a, for all initiation functions and requirements.			

(a) Must satisfy Gaseous Effluent Dose Rate Requirements in Part I of the ODCM.
(b) During CORE ALTERATIONS.
(c) During movement of irradiated fuel assemblies within containment.

3.3 INSTRUMENTATION

3.3.7 Control Room Emergency Filtration System (CREFS) Actuation Instrumentation

LCO 3.3.7 The CREFS actuation instrumentation for each Function in Table 3.3.7-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.7-1

ACTIONS

---NOTE---
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel or train inoperable.	A.1 Place the affected CREFS train(s) in emergency recirculation mode. <u>OR</u> A.2 -------------------NOTE-------------------- Applicable only to Functions 3a and 3b. --- Secure the Control Room makeup air supply fan from the affected air intake.	7 days 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more Functions with two channels or two trains inoperable.	B.1.1 Place one CREFS train in emergency recirculation mode.	Immediately
	AND	
	B.1.2 Enter applicable Conditions and Required Actions for one CREFS train made inoperable by inoperable CREFS actuation instrumentation	Immediately
	OR	
	B.2 -----------------NOTE------------------ Applicable only to Functions 3a and 3b. --- Secure the Control Room makeup air supply fan from the affected air intake.	Immediately
C. Required Action and associated Completion Time for Condition A or B not met in MODE 1, 2, 3, or 4.	C.1 Be in MODE 3.	6 hours
	AND	
	C.2 Be in MODE 5.	36 hours
D. Required Action and associated Completion Time for Condition A or B not met in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	D.2 Suspend movement of irradiated fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---
Refer to Table 3.3.7-1 to determine which SRs apply for each CREFS Actuation Function.

	SURVEILLANCE	FREQUENCY
SR 3.3.7.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.2	Perform COT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.3	Not Used.	
SR 3.3.7.4	Not Used.	
SR 3.3.7.5	Not Used.	
SR 3.3.7.6	---------------------------------NOTE--------------------------------- Verification of setpoint is not required. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program.
SR 3.3.7.7	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

Table 3.3.7-1 (page 1 of 1)
CREFS Actuation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1. Manual Initiation	1, 2, 3, 4, 5, and 6, (a)	2 trains	SR 3.3.7.6	NA
2. Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4, 5, and 6, (a)	2 trains	SR 3.3.7.2	NA
3. Control Room Radiation				
a. Control Room Air North Intake	1, 2, 3, 4, 5, and 6, (a)	2	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.7	1.4×10^{-4} μCi/ml
b. Control Room Air South Intake	1, 2, 3, 4, 5, and 6, (a)	2	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.7	1.4×10^{-4} μCi/ml
4. Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.			

(a) During movement of irradiated fuel assemblies.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure ≥ the limit specified in the COLR;

b. RCS average temperature ≤ the limit specified in the COLR; and

c. RCS total flow rate ≥ 389,700 gpm and ≥ the limit specified in the COLR.

APPLICABILITY: MODE 1

---NOTE---
Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------------NOTE-------------- Only applicable prior to exceeding 85% RTP after a refueling outage. ----------------------------------- Measured RCS Flow not within limits.	B.1 Maintain THERMAL POWER less than 85% RTP.	Immediately
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is ≥ the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.1.2	Verify RCS average temperature is ≤ the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.1.3	Verify RCS total flow rate is ≥ 389,700 and ≥ the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.4	-----------------------------------NOTE----------------------------------- Not required to be performed until after exceeding 85% RTP after each refueling outage. --- Verify by precision heat balance that RCS total flow rate is ≥ 389,700 and ≥ the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each operating RCS loop average temperature (T_{avg}) shall be ≥ 551°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or more operating RCS loops not within limit.	A.1 Be in MODE 2 with k_{eff} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify RCS T_{avg} in each operating loop ≥ 551°F.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Required Action A.2 shall be completed whenever this Condition is entered. ------------------------------------ Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1 Restore parameter(s) to within limits. AND A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5 with RCS pressure < 500 psig.	6 hours 36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. --------------NOTE-------------- Required Action C.2 shall be completed whenever this Condition is entered. ------------------------------------		
Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits.	Immediately
	AND	
	C.2 Determine RCS is acceptable for continued operation.	Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	----------------------------------NOTE---------------------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. --	
	Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops -- MODES 1 and 2

LCO 3.4.4 Four RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify each RCS loop is in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops -- MODE 3

LCO 3.4.5 Two RCS loops shall be OPERABLE, and either:

a. Two RCS loops shall be in operation when the Rod Control System is capable of rod withdrawal; or

b. One RCS loop shall be in operation when the Rod Control System is not capable of rod withdrawal.

---NOTE---
All reactor coolant pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODE 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RCS loop inoperable.	A.1 Restore required RCS loop to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 4.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required RCS loop not in operation, with Rod Control System capable of rod withdrawal.	C.1 Restore required RCS loop to operation. OR C.2 Place the Rod Control System in a condition incapable of rod withdrawal.	1 hour 1 hour
D. Four RCS loops inoperable. OR No RCS loop in operation.	D.1 Place the Rod Control System in a condition incapable of rod withdrawal. AND D.2 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. AND D.3 Initiate action to restore one RCS loop to OPERABLE status and operation.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ 38% (Unit 1) and ≥ 10% (Unit 2) for required RCS loops.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops -- MODE 4

LCO 3.4.6 Two loops consisting of any combination of RCS loops and residual heat removal (RHR) loops shall be OPERABLE, and one loop shall be in operation.

--NOTES--

1. All reactor coolant pumps (RCPs) and RHR pumps may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature ≤ 350°F unless the secondary side water temperature of each steam generator (SG) is ≤ 50°F above each of the RCS cold leg temperatures.

APPLICABILITY: MODE 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required loop inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status. <u>AND</u> A.2 ------------------NOTE---------------------- Only required if one RHR loop is OPERABLE -- Be in MODE 5.	Immediately 24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two required loops inoperable. <u>OR</u> No RCS or RHR loop in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. <u>AND</u> B.2 Initiate action to restore one loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.6.2	Verify SG secondary side water levels are ≥38% (Unit 1) and ≥10% (Unit 2) for required RCS loops.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops -- MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be $\geq$38% (Unit 1) and $\geq$10% (Unit 2).

---NOTES---

1. The RHR pump of the loop in operation may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with any RCS cold leg temperature ≤ 350°F unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable. AND Required SGs secondary side water levels not within limits.	A.1 Initiate action to restore a second RHR loop to OPERABLE status. OR A.2 Initiate action to restore required SG secondary side water levels to within limits.	Immediately Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.7.2	Verify SG secondary side water level is ≥38% (Unit 1) and ≥10% (Unit 2) in required SGs.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops -- MODE 5, Loops Not Filled

LCO 3.4.8 Two residual heat removal (RHR) loops shall be OPERABLE and one RHR loop shall be in operation.

---NOTES---

1. All RHR pumps may be removed from operation for ≤ 1 hour provided:

    a. The core outlet temperature is maintained at least 10°F below saturation temperature.

    b. No operations are permitted that would cause introduction of coolant into the RCS with boron concentration less than required to meet the SDM of LCO 3.1.1; and

    c. No draining operations to further reduce the RCS water volume are permitted.

2. One RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

APPLICABILITY: MODE 5 with RCS loops not filled

---NOTE---

While this LCO is not met, entry into MODE 5, Loops Not Filled from MODE 5, Loops filled is not permitted.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable.	A.1 Initiate action to restore RHR loop to OPERABLE status.	Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1. AND B.2 Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR loop is in operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ 92%; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Be in MODE 3. AND A.2 Fully insert all rods. AND A.3 Place Rod Control System in a condition incapable of rod withdrawal. AND A.4 Be in MODE 4.	6 hours 6 hours 6 hours 12 hours
B. One required group of pressurizer heaters inoperable.	B.1 Restore required group of pressurizer heaters to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 92%.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 150 kW.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Three pressurizer safety valves shall be OPERABLE with lift settings $\geq$ 2410 psig and $\leq$ 2485 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures > 320°F

--NOTE--
The lift settings are not required to be within the LCO limits during MODES 3 and 4 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for 54 hours following entry into MODE 3 provided a preliminary cold setting was made prior to heatup.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1 Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Two or more pressurizer safety valves inoperable.	B.1 Be in MODE 3. AND B.2 Be in MODE 4 with any RCS cold leg temperatures $\leq$ 320°F.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

--NOTE--
Separate Condition entry is allowed for each PORV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more PORVs inoperable and capable of being manually cycled.	A.1 Close and maintain power to associated block valve.	1 hour
B. One PORV inoperable and not capable of being manually cycled.	B.1 Close associated block valve.	1 hour
	AND	
	B.2 Remove power from associated block valve.	1 hour
	AND	
	B.3 Restore PORV to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One block valve inoperable.	-----------------------NOTE------------------------ Required Actions do not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2. ---	
	C.1 Place associated PORV in manual control.	1 hour
	AND	
	C.2 Restore block valve to OPERABLE status.	72 hours
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 4	12 hours
E. Two PORVs inoperable and not capable of being manually cycled.	E.1 Close associated block valves.	1 hour
	AND	
	E.2 Remove power from associated block valves.	1 hour
	AND	
	E.3 Be in MODE 3	6 hours
	AND	
	E.4 Be in MODE 4	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. More than one block valve inoperable.	----------NOTE---------- Required Actions do not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2. --------------------	
	F.1 Place associated PORVs in manual control.	1 hour
	AND	
	F.2 Restore one block valve to OPERABLE status	2 hours
G. Required Action and associated Completion Time of Condition F not met.	G.1 Be in MODE 3.	6 hours
	AND	
	G.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	----------NOTES---------- 1. Not required to be performed with block valve closed in accordance with the Required Action of this LCO. 2. Not required to be performed prior to entry into MODE 3. --------------------	
	Perform a complete cycle of each block valve.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.2	-----------------------------------NOTE----------------------------------- Not required to be performed prior to entry into MODE 3. --- Perform a complete cycle of each PORV.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP) System

LCO 3.4.12 An LTOP System shall be OPERABLE with a maximum of zero safety injection pumps and two charging pumps capable of injecting into the RCS and the accumulators isolated and one of the following pressure relief capabilities:

a. Two power operated relief valves (PORVs) with lift settings within the limits specified in the PTLR, or

b. Two residual heat removal (RHR) suction relief valves with setpoints ≥ 436.5 psig and ≤ 463.5 psig, or

c. One PORV with a lift setting within the limits specified in the PTLR and one RHR suction relief valve with a setpoint ≥ 436.5 psig and ≤ 463.5 psig, or

d. The RCS depressurized and an RCS vent of ≥ 2.98 square inches.

--NOTE--

Accumulator may be unisolated when accumulator pressure is less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

APPLICABILITY: MODE 4, MODE 5,
MODE 6 when the reactor vessel head is on

--NOTE--

The LCO is not applicable when all RCS cold leg temperatures are > 320°F and the following conditions are met:

a. At least one reactor coolant pump is in operation, and

b. Pressurizer level is ≤ 92%, and

c. The plant heatup rate is limited to 60°F in any one hour period.

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable when entering MODE 4.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more safety injection pumps capable of injecting into the RCS.	A.1 Initiate action to verify a maximum of zero safety injection pumps are capable of injecting into the RCS.	Immediately
B. Three charging pumps capable of injecting into the RCS.	B.1 Initiate action to verify a maximum of two charging pumps are capable of injecting into the RCS.	Immediately
C. An accumulator not isolated when the accumulator pressure is greater than or equal to the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	C.1 Isolate affected accumulator.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Increase RCS cold leg temperature to > 320°F. AND Verify at least one reactor coolant pump is in operation. AND Pressurizer level is ≤ 92%. AND The plant heatup rate is limited to 60°F in any one hour period.	12 hours
	OR	
	D.2 Increase RCS average temperature to > 350°F.	12 hours
	OR	
	D.3 Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	12 hours
E. One required RCS relief valve inoperable in MODE 4.	E.1 Restore required RCS relief valve to OPERABLE status.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One required RCS relief valve inoperable in MODE 5 or 6.	F.1 Restore required RCS relief valve to OPERABLE status.	24 hours
G. Two required RCS relief valves inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A, B, D, E, or F not met. <u>OR</u> LTOP System inoperable for any reason other than Condition A, B, C, D, E, or F.	G.1 Depressurize RCS and establish RCS vent of ≥ 2.98 square inches.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	Verify a maximum of zero safety injection pumps are capable of injecting into the RCS.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.2	Verify a maximum of two charging pumps are capable of injecting into the RCS.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.3	Verify each accumulator is isolated when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.4	Verify RHR suction isolation valves are open for each required RHR suction relief valve.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.5	Verify required RCS vent ≥ 2.98 square inches open.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.6	Verify PORV block valve is open for each required PORV.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.7	Not Used.	
SR 3.4.12.8	---------------------------------NOTE--------------------------------- Not required to be performed until 12 hours after decreasing any RCS cold leg temperature to ≤ 350°F. --- Perform a COT on each required PORV, excluding actuation.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.12.9	Perform CHANNEL CALIBRATION for each required PORV actuation channel.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

d. 150 gallons per day primary to secondary LEAKAGE through any one steam generator (SG).

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Pressure boundary LEAKAGE exists. <u>OR</u> Primary to secondary LEAKAGE not within limits	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.13.1	----------NOTES---------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. -------------------- Verify RCS operational LEAKAGE is within limits by performance of RCS water inventory balance.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.13.2	----------NOTE---------- Not required to be performed until 12 hours after establishment of steady state operation. -------------------- Verify primary to secondary LEAKAGE is ≤150 gallons per day through any one SG.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.14 Leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4, except valves in the residual heat removal (RHR) flow path when in, or during the transition to or from, the RHR mode of operation

ACTIONS

-----NOTES-----

1. Separate Condition entry is allowed for each flow path.

2. Enter applicable Conditions and Required Actions for systems made inoperable by an inoperable PIV.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flow paths with leakage from one or more RCS PIVs not within limit.	----------------------NOTE----------------------- Each valve used to satisfy Required Action A.1 and Required Action A.2 must have been verified to meet SR 3.4.14.1 and be in the reactor coolant pressure boundary or the high pressure portion of the system. ---	
	A.1 Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, deactivated automatic, or check valve.	4 hours
	AND	
	A.2.1 Isolate the high pressure portion of the affected system from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve.	72 hours
	OR	
	A.2.2 Restore RCS PIV to within limits.	72 hours
B. Required Action and associated Completion Time for Condition A not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours
C. RHR System interlock function inoperable.	C.1 Isolate the affected penetration by use of one closed manual or deactivated automatic valve.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1	-----------------------------------NOTES---------------------------------- 1. Not required to be performed in MODES 3 and 4. 2. Not required to be performed on the RCS PIVs located in the RHR flow path when in the shutdown cooling mode of operation. 3. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. ---	
	Verify leakage from each RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.	In accordance with the Inservice Testing Program, and in accordance with the Surveillance Frequency Control Program. <u>AND</u> Prior to entering MODE 2 whenever the unit has been in MODE 5 for 7 days or more, and if leakage testing has not been performed in the previous 9 months except for valves 8701A, 8701B, 8702A and 8702B <u>AND</u> Within 24 hours following check valve actuation due to flow through the valve

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.14.2	Verify RHR System interlock prevents the valves from being opened with a simulated or actual RCS pressure signal $\geq$ 442 psig, except when the valves are open to satisfy LCO 3.4.12.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

a. One Containment Sump Level and Flow Monitoring System;

b. One containment atmosphere particulate radioactivity monitor; and

c. One containment air cooler condensate flow rate monitor or one containment atmosphere radioactivity monitor (gaseous).

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required Containment Sump Level and Flow Monitoring System inoperable.	A.1 -------------------NOTE------------------- Not required until 12 hours after establishment of steady state operation. --- Perform SR 3.4.13.1.	 Once per 24 hours
	AND	
	A.2 Restore Containment Sump Level and Flow Monitoring System to OPERABLE status.	30 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required containment atmosphere particulate radioactivity monitor inoperable.	B.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	<u>OR</u>	
	B.1.2 ------------------NOTE------------------ Not required until 12 hours after establishment of steady state operation. -- Perform SR 3.4.13.1.	Once per 24 hours
	<u>AND</u>	
	B.2 Restore required containment atmosphere particulate radioactivity monitor to OPERABLE status.	30 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C Required containment atmosphere gaseous radioactivity monitor inoperable. AND Required containment air cooler condensate flow rate monitor inoperable.	C.1.1 Analyze grab samples of the containment atmosphere. OR C.1.2 ------------------NOTE------------------ Not required until 12 hours after establishment of steady state operation. -- Perform SR 3.4.13.1. AND C.2.1 Restore required containment atmosphere gaseous radioactivity monitor to OPERABLE status. OR C.2.2 Restore required containment air cooler condensate flow rate monitor to OPERABLE status.	Once per 24 hours Once per 24 hours 30 days 30 days
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours
E. All required monitors inoperable.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.15.1	Perform CHANNEL CHECK of the required containment atmosphere particulate and gaseous radioactivity monitors.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.15.2	Perform COT of the required containment atmosphere particulate and gaseous radioactivity monitors.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required Containment Sump Level and Flow Monitoring System.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.15.4	Perform CHANNEL CALIBRATION of the required containment atmosphere particulate and gaseous radioactivity monitors.	In accordance with the Surveillance Frequency Control Program.
SR 3.4.15.5	Perform CHANNEL CALIBRATION of the required containment air cooler condensate flow rate monitor.	In accordance with the Surveillance Frequency Control Program.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 RCS DOSE EQUIVALENT I-131 and DOSE EQUIVALENT XE-133 specific activity shall be within limits.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 not within limit.	-----------------------NOTE------------------------ LCO 3.0.4.c is applicable. ---	
	A.1 Verify DOSE EQUIVALENT I-131 $\leq$ 60 μCi/gm. <u>AND</u>	Once per 4 hours
	A.2 Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. DOSE EQUIVALENT XE-133 not within limit.	B.1 --------------------NOTE-------------------- LCO 3.0.4.c is applicable. --	
	Restore DOSE EQUIVALENT XE-133 to within limit.	48 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met. <u>OR</u> DOSE EQUIVALENT I-131 > 60 μCi/gm.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	-----------------------------------NOTE----------------------------------- Only required to be performed in MODE 1. -- Verify reactor coolant DOSE EQUIVALENT XE-133 specific activity ≤ 500 μCi/gm.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.16.2	----------NOTE---------- Only required to be performed in MODE 1. -------------------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 0.45 μCi/gm.	In accordance with the Surveillance Frequency Control Program. <u>AND</u> Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period
SR 3.4.16.3	DELETED	DELETED

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube plugging criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

-----------------------------------NOTES-----------------------------------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube plugging criteria and not plugged in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND	
	A.2 Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.1 Accumulators

LCO 3.5.1 Four ECCS accumulators shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS pressure > 1000 psig.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One accumulator inoperable due to boron concentration not within limits.	A.1 Restore boron concentration to within limits.	72 hours
B. One accumulator inoperable for reasons other than Condition A.	B.1 Restore accumulator to OPERABLE status.	24 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Reduce RCS pressure to 1000 ≤ psig.	6 hours 12 hours
D. Two or more accumulators inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.5.1.1	Verify each accumulator isolation valve is fully open.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.1.2	Verify borated water volume in each accumulator is ≥ 6119 gallons and ≤ 6597 gallons.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.1.3	Verify nitrogen cover pressure in each accumulator is ≥ 623 psig and ≤ 644 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.1.4	Verify boron concentration in each accumulator is ≥ 2300 ppm and ≤ 2600 ppm.	In accordance with the Surveillance Frequency Control Program. <u>AND</u> ----------NOTE--------- Only required to be performed for affected accumulators --------------------------- Once within 6 hours after each solution volume increase of ≥ 101 gallons that is not the result of addition from the refueling water storage tank

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.5	Verify power is removed from each accumulator isolation valve operator when RCS pressure is > 1000 psig.	In accordance with the Surveillance Frequency Control Program.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS -- Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

---NOTES---

1. In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

2. Operation in MODE 3 with ECCS pumps made incapable of injecting, pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is allowed for up to 4 hours or until the temperature of all RCS cold legs exceeds 375°F, whichever comes first.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One train inoperable because of the inoperability of a centrifugal charging pump.	A.1 Restore pump to OPERABLE status.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more trains inoperable for reasons other than one inoperable centrifugal charging pump. AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	B.1 Restore train(s) to OPERABLE status.	72 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position with power to the valve operator removed. Number / Position / Function 8802 A&B / Closed / SI Pump to Hot Legs 8809 A&B / Open / RHR to Cold Legs 8835 / Open / SI Pump to Cold Legs 8840 / Closed / RHR to Hot Legs 8806 / Open / SI Pump Suction from RWST 8813 / Open / SI Pump Miniflow Valve	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2	Verify each ECCS manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.3	Verify ECCS piping is full of water.	Prior to entry into MODE 3
SR 3.5.2.4	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.5.2.5	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.6	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.7	Verify, for each ECCS throttle valve listed below, each mechanical position stop is in the correct position. <u>Valve Number</u> 8810A 8816A 8822A 8810B 8816B 8822B 8810C 8816C 8822C 8810D 8816D 8822D	In accordance with the Surveillance Frequency Control Program.
SR 3.5.2.8	Verify, by visual inspection, each ECCS train containment sump suction inlet is not restricted by debris and the suction inlet strainers show no evidence of structural distress or abnormal corrosion.	In accordance with the Surveillance Frequency Control Program.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.3 ECCS -- Shutdown

LCO 3.5.3 One ECCS train shall be OPERABLE.

--NOTE--
An RHR train may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned to the ECCS mode of operation.

APPLICABILITY: MODE 4

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable to ECCS Centrifugal Pump subsystem.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required ECCS residual heat removal (RHR) subsystem inoperable.	A.1 Initiate action to restore required ECCS RHR subsystem to OPERABLE status.	Immediately
B. Required ECCS Centrifugal Charging Pump subsystem inoperable.	B.1 Restore required ECCS Centrifugal Charging Pump subsystem to OPERABLE status.	1 hour
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 5.	24 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.5.3.1	The following SRs are applicable for all equipment required to be OPERABLE: SR 3.5.2.1 SR 3.5.2.4 SR 3.5.2.7 SR 3.5.2.8	In accordance with applicable SRs

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.4 Refueling Water Storage Tank (RWST)

LCO 3.5.4 The RWST shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RWST boron concentration not within limits. OR RWST borated water temperature not within limits.	A.1 Restore RWST to OPERABLE status.	8 hours
B. RWST inoperable for reasons other than Condition A.	B.1 Restore RWST to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	------------------------------------NOTE------------------------------------ Only required to be performed when ambient air temperature is < 40°F or > 120°F. -- Verify RWST borated water temperature is ≥ 40°F and ≤ 120°F.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.4.2	Verify RWST borated water volume is ≥ 473,731 gallons.	In accordance with the Surveillance Frequency Control Program.
SR 3.5.4.3	Verify RWST boron concentration is ≥ 2400 ppm and ≤ 2600 ppm.	In accordance with the Surveillance Frequency Control Program.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.5 Seal Injection Flow

LCO 3.5.5 Reactor coolant pump seal injection flow shall be ≤ 40 gpm with RCS pressure ≥ 2215 psig and ≤ 2255 psig and the charging flow control valve full open.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Seal injection flow not within limit.	A.1 Adjust manual seal injection throttle valves to give a flow within limit with RCS pressure ≥ 2215 psig and ≤ 2255 psig and the charging flow control valve full open.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.5.1	-----------------------------------NOTE----------------------------------- Not required to be performed until 4 hours after the Reactor Coolant System pressure stabilizes at ≥ 2215 psig and ≤ 2255 psig. --- Verify manual seal injection throttle valves are adjusted to give a flow within limit with RCS pressure ≥ 2215 psig and ≤ 2255 psig and the charging flow control valve full open.	In accordance with the Surveillance Frequency Control Program.

3.6 CONTAINMENT SYSTEMS

3.6.1 Containment

LCO 3.6.1 Containment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment inoperable.	A.1 Restore containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1	Perform required visual examinations and leakage rate testing except for containment air lock testing, in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEM

3.6.2 Containment Air Locks

LCO 3.6.2 Two containment air locks shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

--NOTES--

1. Entry and exit is permissible to perform repairs on the affected air lock components.

2. Separate Condition entry is allowed for each air lock.

3. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when air lock leakage results in exceeding the overall containment leakage rate.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment air locks with one containment air lock door inoperable.	-----------------------NOTES---------------------- 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit is permissible for 7 days under administrative controls if both air locks are inoperable. ---	
	A.1 Verify the OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	A.2 Lock the OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>	
	A.3 --------------------NOTE--------------------- Air lock doors in high radiation areas may be verified locked closed by administrative means. ---	
	Verify the OPERABLE door is locked closed in the affected air lock.	Once per 31 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more containment air locks with containment air lock interlock mechanism inoperable.	-----------------------NOTES---------------------- 1. Required Actions B.1, B.2, and B.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit of containment is permissible under the control of a dedicated individual. ---	
	B.1 Verify an OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	B.2 Lock an OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>	
	B.3 ---------------------NOTE-------------------- Air lock doors in high radiation areas may be verified locked closed by administrative means. --	
	Verify an OPERABLE door is locked closed in the affected air lock.	Once per 31 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	AND	
	C.2 Verify a door is closed in the affected air lock.	1 hour
	AND	
	C.3 Restore air lock to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.2.1	-----NOTES----- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1. ---------- Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.2.2	Verify only one door in the air lock can be opened at a time.	In accordance with the Surveillance Frequency Control Program.

3.6 CONTAINMENT SYSTEMS

3.6.3 Containment Isolation Valves

LCO 3.6.3 Each containment isolation valve shall be OPERABLE.

--NOTE--
Not applicable to Main Steam Safety Valves (MSSVs), Main Steam Isolation Valves (MSIVs), Feedwater Isolation Valves (FIVs) and Associated Bypass Valves, and Steam Generator Atmospheric Relief Valves (ARVs).

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

--NOTES--
1. Penetration flow path(s) except for 48 inch containment and 12 inch hydrogen purge valve flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by containment isolation valves.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Only applicable to penetration flow paths with two containment isolation valves. ------------------------------------ One or more penetration flow paths with one containment isolation valve inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. <u>AND</u> A.2 --------------------NOTES------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. --- Verify the affected penetration flow path is isolated.	4 hours Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ---------------NOTE------------- Only applicable to penetration flow paths with two containment isolation valves. ------------------------------------- One or more penetration flow paths with two containment isolation valves inoperable except for containment purge, hydrogen purge or containment pressure relief valve leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------------NOTE------------- Only applicable to penetration flow paths with only one containment isolation valve and a closed system. ------------------------------------ One or more penetration flow paths with one containment isolation valve inoperable.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours
	AND	
	C.2 -------------------NOTES-------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. -- Verify the affected penetration flow path is isolated.	Once per 31 days
D. One or more penetration flow paths with one or more containment purge, hydrogen purge or containment pressure relief valves not within leakage limits.	D.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND	24 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	D.2 --------------------NOTES------------------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed or otherwise secured may be verified by administrative means. --- Verify the affected penetration flow path is isolated.	 Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment
	<u>AND</u> D.3 Perform SR 3.6.3.7 for the resilient seal purge valves closed to comply with Required Action D.1.	 Once per 92 days
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. <u>AND</u> E.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.3.1	Verify each 48 inch Containment Purge and 12 inch Hydrogen Purge valve is sealed closed, except for one purge valve in a penetration flow path while in Condition D of this LCO.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.3.2	Not used.	
SR 3.6.3.3	-------------------------------NOTES------------------------------- Valves and blind flanges in high radiation areas may be verified by use of administrative controls. --	
	Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.3.4	-------------------------------NOTES------------------------------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative means. 2. The blind flange on the fuel transfer canal need not be verified closed except after each drainage of the canal. --	
	Verify each containment isolation manual valve and blind flange that is located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.5	Verify the isolation time of each automatic power operated containment isolation valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.3.6	Not used.	
SR 3.6.3.7	-----------------------------------NOTE----------------------------------- This surveillance is not required when the penetration flow path is isolated by a leak tested blank flange. -- Perform leakage rate testing for containment purge, hydrogen purge and containment pressure relief valves with resilient seals.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.3.8	Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.3.9	Not used.	
SR 3.6.3.10	Not used.	
SR 3.6.3.11	Not used.	
SR 3.6.3.12	Not used.	
SR 3.6.3.13	Not used.	

3.6 CONTAINMENT SYSTEMS

3.6.4 Containment Pressure

LCO 3.6.4 Containment pressure shall be ≥ - 0.3 psig and ≤ + 1.3 psig.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment pressure not within limits.	A.1 Restore containment pressure to within limits.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1	Verify containment pressure is within limits.	In accordance with the Surveillance Frequency Control Program.

3.6 CONTAINMENT SYSTEMS

3.6.5 Containment Air Temperature

LCO 3.6.5 Containment average air temperature shall be ≤ 120°F.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment average air temperature not within limit.	A.1 Restore containment average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.5.1	Verify containment average air temperature is within limit.	In accordance with the Surveillance Frequency Control Program.

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System

LCO 3.6.6 Two containment spray trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One containment spray train inoperable.	A.1 Restore containment spray train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 84 hours
C. Two containment spray trains inoperable.	C.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.6.2	Not used.	
SR 3.6.6.3	Not used.	
SR 3.6.6.4	Verify each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.6.6.5	Verify each automatic containment spray valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.6.6	Verify each containment spray pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.6.6.7	Not used.	
SR 3.6.6.8	Verify each spray nozzle is unobstructed.	Following maintenance which could result in nozzle blockage

3.6 CONTAINMENT SYSTEMS

3.6.7 Spray Additive System

LCO 3.6.7 The Spray Additive System shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spray Additive System inoperable.	A.1 Restore Spray Additive System to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Verify the spray additive system ensures an equilibrium sump pH ≥ 7.1 using NaOH.	In accordance with the Technical Requirements Manual

3.7 PLANT SYSTEMS

3.7.1 Main Steam Safety Valves (MSSVs)

LCO 3.7.1 Five MSSVs per steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

--NOTE--
Separate Condition entry is allowed for each MSSV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more steam generators with one MSSV inoperable and the Moderator Temperature Coefficient (MTC) zero or negative at all power levels.	A.1 Reduce THERMAL POWER to ≤68% RTP.	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more steam generators with two or more MSSVs inoperable. <u>OR</u> One or more steam generators with one MSSV inoperable and the MTC positive at any power level.	B.1 Reduce Thermal Power to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	4 hours
	<u>AND</u>	
	B.2 --------------------NOTE--------------------- Only required in MODE 1. --- Reduce the Power Range Neutron Flux-High reactor trip setpoint to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	36 hours
C. Required Action and associated Completion Time not met. <u>OR</u> One or more steam generators with $\geq$ 4 MSSVs inoperable.	C.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	C.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	------------------------------NOTE------------------------------ Only required to be performed in MODES 1 and 2. -- Verify each required MSSV lift setpoint per Table 3.7.1-2 in accordance with the Inservice Testing Program. Following testing, lift setting shall be within ± 1%.	In accordance with the Inservice Testing Program

Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
4	≤ 61
3	≤ 43
2	≤ 26

Table 3.7.1-2 (page 1 of 1)
Main Steam Safety Valve Lift Settings

VALVE NUMBER				LIFT SETTING (psig ± 3%)
STEAM GENERATOR				
#1	#2	#3	#4	
MS-021	MS-058	MS-093	MS-129	1185
MS-022	MS-059	MS-094	MS-130	1195
MS-023	MS-060	MS-095	MS-131	1205
MS-024	MS-061	MS-096	MS-132	1215
MS-025	MS-062	MS-097	MS-133	1235

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs)

LCO 3.7.2 Four MSIVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 except when all MSIVs are closed and deactivated.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSIV inoperable in MODE 1.	A.1 Restore MSIV to OPERABLE status.	8 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2.	6 hours
C. --------------NOTE-------------- Separate Condition entry is allowed for each MSIV. ------------------------------------- One or more MSIV inoperable in MODE 2 or 3.	C.1 Close MSIV. AND C.2 Verify MSIV is closed.	8 hours Once per 7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.2.1	-----------------------------------NOTE----------------------------------- Only required to be performed in MODES 1 and 2. --- Verify the isolation time of each MSIV is within limits.	 In accordance with the Inservice Testing Program
SR 3.7.2.2	-----------------------------------NOTE----------------------------------- Only required to be performed in MODES 1 and 2. --- Verify each MSIV actuates to the isolation position on an actual or simulated actuation signal.	 In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.3 Feedwater Isolation Valves (FIVs) and Feedwater Control Valves (FCVs) and Associated Bypass Valves

LCO 3.7.3 Four FIVs, four FCVs, and associated bypass valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3 except when FIV, FCV or associated bypass valve is either closed and de-activated or isolated by a closed manual valve.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more FIVs inoperable.	A.1 Close or isolate FIV.	72 hours
	AND	
	A.2 Verify FIV is closed or isolated.	Once per 7 days
B. One or more FCVs inoperable.	B.1 Close or isolate FCV.	72 hours
	AND	
	B.2 Verify FCV is closed or isolated.	Once per 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more FIV or FCV bypass valves inoperable.	C.1 Close or isolate bypass valve.	72 hours
	AND	
	C.2 Verify bypass valve is closed or isolated.	Once per 7 days
D. Two valves in the same flowpath inoperable	D.1 Isolate affected flow path.	8 hours
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3.	6 hours
	AND	
	E.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify the isolation time of each FIV, FCV, and associated bypass valves is within limits.	In accordance with the Inservice Testing Program
SR 3.7.3.2	Verify each FIV, FCV, and associated bypass valves actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.4 Steam Generator Atmospheric Relief Valves (ARVs)

LCO 3.7.4 Four ARV lines shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ARV line inoperable.	A.1 Restore required ARV line to OPERABLE status.	7 days
B. Two required ARV lines inoperable.	B.1 Restore at least one ARV line to OPERABLE status.	72 hours
C. Three or more required ARV lines inoperable.	C.1 Restore at least two ARV lines to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 4	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify one complete cycle of each ARV.	In accordance with the Inservice testing Program
SR 3.7.4.2	Verify one complete cycle of each ARV block valve.	In accordance with the Inservice testing Program

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW) System

LCO 3.7.5 Three AFW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

--NOTE--
LCO 3.0.4.b is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One steam supply to turbine driven AFW pump inoperable.	A.1 Restore steam supply to OPERABLE status.	7 days
B. One AFW train inoperable for reasons other than Condition A.	B.1 Restore AFW train to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time for Condition A or B not met. OR Two AFW trains inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 18 hours
D. Three AFW trains inoperable.	D.1 -------------------NOTE------------------- LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one AFW train is restored to OPERABLE status. -- Initiate action to restore one AFW train to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	-----------------------------------NOTE----------------------------------- AFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW mode of operation. ---	
	Verify each AFW manual, power operated, and automatic valve in each water flow path, and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.5.2	-----------------------------------NOTE----------------------------------- Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 532 psig in the steam generator. ---	
	Verify the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice testing Program
SR 3.7.5.3	-----------------------------------NOTE----------------------------------- AFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW mode of operation. ---	
	Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.5.4	-----------------------------------NOTES--------------------------------- 1. Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 532 psig in the steam generator. 2. AFW train(s) may be considered OPERABLE during alignment and operation for steam generator level control, if it is capable of being manually realigned to the AFW operation. -- Verify each AFW pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tank (CST)

LCO 3.7.6 The CST level shall be ≥ 53%.

APPLICABILITY: MODES 1, 2, and 3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CST level not within limit.	A.1 Verify by administrative means OPERABILITY of backup water supply. AND A.2 Restore CST level to within limit.	4 hours AND Once per 12 hours thereafter 7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the CST level is ≥ 53%.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.7 Component Cooling Water (CCW) System

LCO 3.7.7 Two CCW trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CCW train inoperable.	-----------------------NOTE------------------------ Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," for residual heat removal loops made inoperable by CCW. -- A.1 Restore CCW train to OPERABLE status.	 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	-----------------------------------NOTE----------------------------------- Isolation of CCW flow to individual components does not render the CCW System inoperable. --- Verify each CCW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.7.2	Verify each CCW automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.7.3	Verify each CCW pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.8 Station Service Water System (SSWS)

LCO 3.7.8 Two SSWS trains and a SSW Pump on the opposite unit with its associated cross-connects shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required SSW Pump on the opposite unit or its associated cross-connects inoperable.	A.1 Restore a SSW Pump on the opposite unit to OPERABLE status. AND A.2 Restore associated cross-connects to OPERABLE status.	7 days 7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One SSWS train inoperable.	B.1 --------------------NOTES------------------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources -- Operating," for emergency diesel generator made inoperable by SSWS. 2. Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops -- MODE 4," for residual heat removal loops made inoperable by SSWS. -- Restore SSWS train to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	---NOTE--- Isolation of SSWS flow to individual components does not render the SSWS inoperable. --- Verify each SSWS manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.8.2	Verify one complete cycle of each required cross-connect valve that is not locked open.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.8.3	Verify each SSW pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.9 Ultimate Heat Sink (UHS)

LCO 3.7.9 The Safe Shutdown Impoundment (SSI) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SSI level less than required.	A.1 Restore SSI level to within limits.	7 days
B. Required Action and associated Completion Time of Condition A not met. OR SSI inoperable for reasons other than Condition A.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Verify water level of SSI is ≥ 770 ft mean sea level.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.2	Verify station service water intake temperature is $\leq$ 102°F.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.10 Control Room Emergency Filtration/Pressurization System (CREFS)

LCO 3.7.10 Two CREFS trains shall be OPERABLE

-----NOTE-----
The Control Room envelope (CRE) boundary may be opened intermittently under administrative controls.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CREFS train inoperable for reasons other than Condition B.	A.1 Restore CREFS train to OPERABLE status.	7 days
B. One or more CREFS Trains inoperable due to inoperable CRE boundary in MODES 1, 2, 3, and 4.	B.1 Initiate action to implement mitigating actions.	Immediately
	AND	
	B.2 Verify mitigating actions to ensure CRE occupant exposures to radiological, chemical, and smoke hazards will not exceed limits.	24 hours
	AND	
	B.3 Restore CRE boundary to OPERABLE status.	90 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, 3, or 4.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours
D. Required Action and associated Completion Time of Condition A not met in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1 Place OPERABLE CREFS train in emergency recirculation mode. OR D.2.1 Suspend CORE ALTERATIONS. AND D.2.2 Suspend movement of irradiated fuel assemblies.	Immediately Immediately Immediately
E. Two CREFS trains inoperable in MODE 5 or 6, or during movement of irradiated fuel assemblies. OR One or more CREFS trains inoperable due to an inoperable CRE boundary in MODE 5 or 6, or during movement of irradiated fuel assemblies.	E.1 Suspend CORE ALTERATIONS. AND E.2 Suspend movement of irradiated fuel assemblies.	Immediately Immediately
F. Two CREFS trains inoperable in MODE 1, 2, 3, or 4 for reasons other than Condition B.	F.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Operate each CREFS trains Emergency Pressurization Unit for ≥ 10 continuous hours with the heaters operating and Emergency Filtration Unit ≥ 15 minutes.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.10.2	Perform required CREFS testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.10.3	Verify each CREFS train actuates on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.10.4	Perform required CRE unfiltered air inleakage testing in accordance with the Control Room Envelope Habitability Program.	In accordance with the Control Room Envelope Habitability Program

3.7 PLANT SYSTEMS

3.7.11 Control Room Air Conditioning System (CRACS)

LCO 3.7.11 Two CRACS trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CRACS train inoperable.	A.1 Restore CRACS train to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, 3, or 4.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours
C. Required Action and associated Completion Time of Condition A not met in MODE 5, or 6, or during movement of irradiated fuel assemblies.	C.1 Place OPERABLE CRACS train in operation. OR C.2.1 Suspend CORE ALTERATIONS. AND C.2.2 Suspend movement of irradiated fuel assemblies.	Immediately Immediately Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two CRACS trains inoperable in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1.1 Verify at least 100% of the required heat removal capability equivalent to a single OPERABLE train available.	Immediately
	<u>AND</u>	
	D.1.2 Restore the CRACS trains to OPERABLE status.	30 days
	<u>OR</u>	
	D.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	D.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
E. Two CRACS trains inoperable in MODE 1, 2, 3, or 4.	E.1.1 Verify at least 100% of the required heat removal capability equivalent to a single OPERABLE train available.	Immediately
	<u>AND</u>	
	E.1.2 Restore one CRACS train to OPERABLE status.	30 days
	<u>OR</u>	
	E.2 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Verify each CRACS train has the capability to remove the assumed heat load.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.12 Primary Plant Ventilation System (PPVS) - ESF Filtration Trains

LCO 3.7.12 Two PPVS trains shall be OPERABLE

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. With one or more PPVS trains unable to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel Buildings $\geq$ 0.05 inch water gauge.	A.1 Restore PPVS trains to OPERABLE status.	30 days
B. With one or more PPVS trains unable to maintain a negative pressure envelope in the Auxiliary, Safeguards, and Fuel Buildings $\geq$ 0.01 inch water gauge.	B.1 Restore ability of PPVS trains to maintain a negative pressure envelope of $\geq$ 0.01 inch water gauge pressure.	7 days
C. One PPVS train inoperable for any reason except Conditions A or B.	C.1 Restore PPVS train to OPERABLE status.	7 days
D. Required Actions and associated Completion Times not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.12.1	Operate each ESF Filtration train for ≥ 10 continuous hours with the heaters operating.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.12.2	Perform required ESF Filtration Unit filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.12.3	Verify each PPVS train actuates on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.12.4	Verify one PPVS train can maintain a pressure ≤ -0.05 inches water gauge relative to atmospheric pressure during the post accident mode of operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.12.5	Not used.	
SR 3.7.12.6	Verify each PPVS non-ESF fan stops on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.13 Fuel Building Air Cleanup System (FBACS)

NOT USED

3.7 PLANT SYSTEMS

3.7.14 Penetration Room Exhaust Air Cleanup System (PREACS)

NOT USED

3.7 PLANT SYSTEMS

3.7.15 Fuel Storage Area Water Level

LCO 3.7.15 The fuel storage area water level shall be ≥ 23 ft over the top of the storage racks

APPLICABILITY: During movement of irradiated fuel assemblies in a spent fuel storage area.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel storage area water level not within limit.	A.1 ------------------NOTE------------------- LCO 3.0.3 is not applicable. --- Suspend movement of irradiated fuel assemblies in the fuel storage area.	 Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.15.1	Verify the fuel storage area water level is ≥ 23 ft above the top of the storage racks.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.16 Fuel Storage Pool Boron Concentration

LCO 3.7.16 The fuel storage pool boron concentration shall be ≥ 2400 ppm.

APPLICABILITY: When fuel assemblies are stored in the fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel storage pool boron concentration not within limit.	------------------------NOTE------------------------ LCO 3.0.3 is not applicable. --	
	A.1 Suspend movement of fuel assemblies in the fuel storage pool	Immediately
	AND	
	A.2 Initiate action to restore fuel storage pool boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.16.1	Verify the fuel storage pool boron concentration is within limit.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.17 Spent Fuel Assembly Storage

LCO 3.7.17 New or spent fuel assemblies will be stored in compliance with Figure 3.7.17-1.

APPLICABILITY: Whenever any fuel assembly is stored in Region II racks of the spent fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 ------------------NOTE------------------- LCO 3.0.3 is not applicable. --- Initiate action to move fuel as necessary to restore compliance.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.17.1	Verify by administrative means the acceptability of fuel movement plans and the resulting storage configuration in accordance with Figure 3.7.17-1.	Prior to moving a fuel assembly into any Region II storage location.

Figure 3.7.17-1 (page 1 of 3)
Spent Fuel Pool Loading Restrictions

All 2x2 Region II storage cell arrays shall comply with one of the Arrays Definitions below. Each storage location is a corner location for up to 4 separate 2x2 arrays.

A. Arrays II-A through II-E designate the pattern of fuel which may be stored in any 2x2 Array, and are dependent upon Fuel Category.

B. Fuel Categories 1-6 are determined based on Fuel Burnup, Initial Enrichment, Decay Time, and Fuel Group.

C. Fuel Group F1 assemblies have a nominal rod outer diameter of 0.374 inches. Fuel Group F2 assemblies have a nominal rod outer diameter of 0.360 inches.

<table>
<tr><th>Array Definition</th><th colspan="4">Illustration</th></tr>
<tr><td rowspan="2"><u>Array II-A</u>
Category 6 assembly in every cell. Only valid for two rows adjacent to the SFP wall. The two rows adjacent to Array II-A must be Array II-B, and the empty cell in Array II-B must be adjacent to Array II-A.</td><td rowspan="2">W
A
L
L</td><td>6</td><td>6</td><td rowspan="2">Array
II-B</td></tr>
<tr><td>6</td><td>6</td></tr>
</table>

<table>
<tr><td rowspan="2"><u>Array II-B</u>
Cateory 4 fuel assembly in 3 out of 4 cells, with empty cell in the fourth cell.</td><td>4</td><td>4</td></tr>
<tr><td>X</td><td>4</td></tr>
</table>

<table>
<tr><td rowspan="2"><u>Array II-C</u>
Pattern which contains fuel in 3 out of 4 cells, including two diagonally-opposed Category 5 assemblies, one Category 3 assembly, and one empty location. Only Fuel Group F2 assemblies may be stored in Array II-C.</td><td>5</td><td>3</td></tr>
<tr><td>X</td><td>5</td></tr>
</table>

<table>
<tr><td rowspan="2"><u>Array II-D</u>
Checkerboard pattern of two diagonally-opposed Category 2 assemblies with two diagonally-opposed empty cells.</td><td>2</td><td>X</td></tr>
<tr><td>X</td><td>2</td></tr>
</table>

<table>
<tr><td rowspan="2"><u>Array II-E</u>
1 out of 4 storage array, with 3 empty cells.</td><td>X</td><td>X</td></tr>
<tr><td>X</td><td>1</td></tr>
</table>

Figure 3.7.17-1 (page 2 of 3)

Notes:

1. Fuel Categories are ranked in order of relative reactivity, from Category 1 to 6. Fuel Category 1 assemblies have the highest reactivity, and Fuel Category 6 assemblies have the lowest.

2. All Fresh Fuel Assemblies (assemblies with a burnup value of 0.0 MWD/MTU) should be considered Category 1 fuel, independent of Fuel Group or Enrichment.

   a. In Fuel Group F1, Fuel Category 1 is fresh fuel up to 3.5 weight percent U-235 Initial Enrichment.

   b. In Fuel Group F2, Fuel Category 1 is fresh fuel up to 5.0 weight percent U-235 Initial Enrichment.

3. Fuel Category 2 is any Non-Fresh fuel assembly up to 3.5 weight percent U-235 Initial Enrichment (Burnup Requirement is > 0 MWD/MTU).

4. For all other fuel, Fuel Categories are determined as follows:

   a. For Initial Enrichment values below the Minimum Applicable Initial Enrichment values of Table 3.7.17-1, the Fitting Coefficients of Tables 3.7.17-2 and 3.7.17-3 are not applicable. The Minimum Burnup Requirement for the corresponding Category is > 0 MWD/MTU.

   b. For Fuel Group F1 assemblies, determine the Fitting Coefficients A_1 - A_4 using Table 3.7.17-2. Note that Table 3.7.17-2 is only applicable to fuel with $\geq$ 10 years of decay time, and an Initial Enrichment of $\leq$ 3.5 weight percent.

   c. For Fuel Group F2 assemblies, determine the Fitting Coefficients A_1 - A_4 using Table 3.7.17-3.

   d. The required Minimum Burnup value (in MWD/MTU) for each Fuel Category is calculated based on Initial Enrichment (En) and the appropriate fitting coefficients, using the equation below. If the fuel assembly burnup is greater than or equal to the calculated Minimum Burnup value, then the fuel may be classified into this Fuel Category.

      Minimum Burnup = $1{,}000 \times [A_1 \times En^3 + A_2 \times En^2 + A_3 \times En + A_4]$

   e. All relevant uncertainties are explicitly included in the criticality analysis. No additional allowance for burnup uncertainty or initial enrichment uncertainty is required.

Figure 3.7.17-1 (page 3 of 3)

Notes (continued):

f. Conservatively low values of Decay Time may be used to calculate the Minimum Burnup value, or interpolation may be used. If interpolation is used, Minimum Burnup values for tabulated Decay Time values above and below the actual value should first be determined. Next, linear interpolation between these values may be used to determine the Minimum Burnup value. No extrapolation beyond 20 years is permitted.

g. Initial Enrichment (En) is the nominal U-235 weight percent enrichment of the central zone region of fuel, excluding axial blankets, prior to fuel depletion.

h. If the computed Minimum Burnup value $\leq$ 0 MWD/MTU, the Minimum Burnup Requirement is > 0 MWD/MTU.

5. In all Arrays, an assembly with a higher Fuel Category number can be utilized in place of any fuel assembly with a lower Fuel Category Number, with the following exception.

   a. Fuel Group F1 assemblies are not allowed to be stored in Array II-C, regardless of Fuel Category.

6. An empty (water-filled) cell can be substituted for any fuel-containing cell in all storage arrays.

7. Any storage array location designated for a fuel assembly can be replaced with non-fissile hardware. Items other than Fuel Assemblies which contain fissile material are restricted to storage in Region I.

8. Fuel assembly inserts approved for use in the reactor core can be inserted in a stored assembly (in the Spent Fuel Pool) without affecting the fuel category.

Table 3.7.17-1

Minimum Applicable Initial Enrichment for
Table 3.7.17-2 and Table 3.7.17-3 Fitting Coefficients

FUEL CATEGORY	FUEL GROUP F1	FUEL GROUP F2
6	1.25	1.20
5	N/A	1.30
4	1.35	1.45
3	N/A	1.45
2	N/A	3.55

Table 3.7.17-2

Fuel Group F1
Nominal Fuel Rod Outer Diameter of 0.374”

Coefficients to Calculate the Minimum Required Fuel Assembly Burnup (Bu)
as a Function of Decay Time and Initial Enrichment (En)

FUEL CATEGORY	DECAY (YRS)	FITTING COEFFICIENTS			
		A_1	A_2	A_3	A_4
6	10	1.4351	-17.3247	73.3805	-67.4585
6	15	1.7078	-18.7916	74.6322	-67.2637
6	20	0.5289	-9.9969	53.7741	-52.6302
4	10	-0.0444	-1.3474	22.7039	-28.0852
4	15	0.2015	-2.6257	24.1016	-28.2473
4	20	0.4646	-4.1432	26.3891	-29.2170

Note: Fuel must have at least 10 years of decay time and less than or equal to 3.5 weight percent Initial Enrichment to utilize Table 3.7.17-2

Table 3.7.17-3

Fuel Group F2
Nominal Fuel Rod Outer Diameter of 0.360"

Coefficients to Calculate the Minimum Required Fuel Assembly Burnup (Bu)
as a Function of Decay Time and Initial Enrichment (En)

FUEL CATEGORY	DECAY (YRS)	FITTING COEFFICIENTS			
		A_1	A_2	A_3	A_4
6	0	0.5789	-7.4498	42.4056	-41.1591
6	5	0.5247	-6.8992	39.7676	-38.6927
6	10	0.2701	-4.4306	31.9841	-32.4674
6	15	0.3105	-4.5582	31.1825	-31.3916
6	20	0.2374	-3.8754	28.8900	-29.4975
5	0	0.9373	-11.2553	54.7226	-54.1769
5	5	0.6169	-8.1494	44.7801	-45.7968
5	10	0.5380	-7.1852	40.7044	-41.9545
5	15	0.5385	-7.0180	39.2299	-40.3213
5	20	0.5200	-6.7906	38.0244	-39.0979
4	0	0.2553	-3.9826	30.6152	-36.7967
4	5	0.2366	-3.6430	28.2160	-33.9749
4	10	0.4387	-5.6018	33.3609	-37.9327
4	15	0.5450	-6.6302	36.0760	-40.0315
4	20	0.6327	-7.4663	38.2724	-41.7257
3	0	0.5317	-6.1006	32.7118	-36.2263
3	5	0.5228	-5.9434	31.2846	-34.4602
3	10	0.5432	-6.1075	31.1578	-33.9933
3	15	0.5206	-5.8897	30.1768	-32.9600
3	20	0.5158	-5.7796	29.4050	-32.0577
2	0	0.0000	1.6738	-8.5396	9.2206

3.7 PLANT SYSTEMS

3.7.18 Secondary Specific Activity

LCO 3.7.18 The specific activity of the secondary coolant shall be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3. <u>AND</u> A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.18.1	Verify the specific activity of the secondary coolant is ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.19 Safety Chilled Water

LCO 3.7.19 Two safety chilled water trains shall be OPERABLE

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One safety chilled water train inoperable.	A.1 Restore safety chilled water train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.19.1	---------------------------------NOTE--------------------------------- Isolation of safety chilled water flow to individual components does not render the safety chilled water system inoperable. --- Verify each safety chilled water manual, power operated, and automatic valve servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.19.2	Verify each safety chilled water pump and chiller starts on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.7 PLANT SYSTEMS

3.7.20 UPS HVAC System

LCO 3.7.20 Two UPS HVAC System Trains shall be OPERABLE

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One UPS HVAC System train inoperable.	A.1 Verify the affected UPS & Distribution Room is supported by an OPERABLE UPS A/C Train.	Immediately
	AND	
	A.2 Restore the inoperable UPS HVAC train to OPERABLE status.	30 days
B. Two UPS HVAC System trains inoperable. OR Required Action A.1 and associated Completion Time not met.	B.1 Verify air circulation is maintained by at least one UPS A/C Train.	Immediately
	AND	
	B.2 Verify the air temperature in the affected UPS & Distribution Room(s) does not exceed the maximum temperature limit for the room(s).	12 hours AND Once per 12 hours thereafter
	AND	
	B.3 Restore UPS HVAC System train to OPERABLE status.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action B.1 and associated Completion Time not met.	C.1 Restore the required support.	1 hour
D. Required Action and associated Completion Time of Required Action A.2, B.2, B.3 or C.1 not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.20.1	Verify each required UPS & Distribution Room Fan Coil Unit operates ≥ 1 continuous hour.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.20.2	Verify each required UPS A/C train operates for ≥ 1 continuous hour.	In accordance with the Surveillance Frequency Control Program.
SR 3.7.20.3	Verify each required UPS A/C train actuates on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources -- Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System;

b. Two diesel generators (DGs) capable of supplying the onsite Class 1E power distribution subsystem(s); and

c. Automatic load sequencers for Train A and Train B.

APPLICABILITY: MODES 1, 2, 3, and 4

---NOTE---
One DG may be synchronized with the offsite power source under administrative controls for the purpose of surveillance testing.

ACTIONS

--NOTE--
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	A.2 --------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. -- Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	A.3 Restore required offsite circuit to OPERABLE status.	72 hours <u>OR</u> 14 days for a one-time outage on XST1 to complete a plant modification to be completed by March 31, 2017.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One DG inoperable.	B.1 Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	B.2 ---------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. --- Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	 4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	B.3.1 Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	<u>OR</u>	
	B.3.2 -------------------NOTE------------------- The SR need not be performed if the DG is already operating and loaded. --- Perform SR 3.8.1.2 for OPERABLE DG(s).	 24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND	
	B.4 Restore DG to OPERABLE status.	72 hours
C. Two required offsite circuits inoperable.	C.1 --------------------NOTE-------------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. --	
	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND	
	C.2 Restore one required offsite circuit to OPERABLE status.	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required offsite circuit inoperable. AND One DG inoperable.	-----------------------NOTE----------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition D is entered with no AC power source to any train. --- D.1 Restore required offsite circuit to OPERABLE status. OR D.2 Restore DG to OPERABLE status.	 12 hours 12 hours
E. Two DGs inoperable.	E.1 Restore one DG to OPERABLE status.	2 hours
F. One SI sequencer inoperable.	F.1 --------------------NOTE--------------------- One required SI sequencer channel may be bypassed for up to 4 hours for surveillance testing provided the other channel is operable. --- Restore SI sequencer to OPERABLE status.	 24 hours
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1 Be in MODE 3. AND G.2 Be in MODE 5.	6 hours 36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Three or more required AC sources inoperable.	H.1 Enter LCO 3.0.3.	Immediately
I. One Blackout Sequencer inoperable	I.1 Declare associated DG inoperable	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.2	---------------------------------NOTES--------------------------------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. --- Verify each DG starts from standby conditions and achieves steady state voltage ≥ 6480 V and ≤ 7150 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.3	-----------------------------------NOTES----------------------------------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2 or SR 3.8.1.7. --- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 6300 kW and ≤ 7000 kW.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.4	Verify each day tank contains ≥ 1440 gal of fuel oil.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank to the day tank.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.7	-----------------------------------NOTE----------------------------------- All DG starts may be preceded by an engine prelube period. --- Verify each DG starts from standby condition and achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz; and b. steady state, voltage ≥ 6480 V and ≤ 7150 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.8	-----------------------------------NOTE----------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify automatic and manual transfer of AC power sources from the normal offsite circuit to each alternate required offsite circuit.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.9	----------------------------------NOTE---------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. -- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is $\leq$ 66.75 Hz; and b. Within 3 seconds following load rejection, the voltage is $\geq$ 6480 V and $\leq$ 7150 V.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.10	Verify each DG does not trip and voltage is maintained $\leq$ 8280 V during and following a load rejection of $\geq$ 6300 kW and $\leq$ 7000 kW.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. ------------------------------------	
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤10 seconds, 2. energizes auto-connected shutdown loads through automatic load sequencer, 3. maintains steady state voltage ≥ 6480 V and ≤ 7150 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.12	-----NOTE----- All DG starts may be preceded by prelube period. ---------- Verify on an actual or simulated Safety Injection (SI) actuation signal each DG auto-starts from standby condition and; a. in ≤ 10 seconds after auto-start and during tests, achieves voltage ≥ 6480 V and frequency ≥ 58.8 Hz; b. Achieves steady state voltage ≥ 6480 V and ≤ 7150 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; c. Operates for ≥ 5 minutes.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.13	-----NOTE----- For Unit 2, testing need only be performed for LOOP concurrent with SI until startup following 2RFO5. ---------- Verify each DG's automatic trips are bypassed on actual or simulated (i) loss of voltage signal on the emergency bus, and (ii) SI actuation signal, except: a. Engine overspeed; and b. Generator differential current.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.14	----------NOTE---------- Momentary transients outside the load and power factor ranges do not invalidate this test. ------------------------------ Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 6900 kW and ≤ 7700 kW; and b. For the remaining hours of the test loaded ≥ 6300 kW and ≤ 7000 kW.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.15	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 6300 kW and ≤ 7000 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ------------------------------ Verify each DG starts and achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz; and b. steady state, voltage ≥ 6480 V and ≤ 7150 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.16	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. -------------------- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.17	----------NOTE---------- This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. -------------------- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated SI actuation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.18	-----------------------------------NOTE----------------------------------- This Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. ---	
	Verify interval between each sequenced load block is within ± 10% of design interval for each automatic load sequencer.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	------------------------------NOTES------------------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not normally be performed in MODE 1 or 2. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated SI actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in $\leq$ 10 seconds, 2. energizes auto-connected emergency loads through load sequencer, 3. achieves steady state voltage $\geq$ 6480 V and $\leq$ 7150 V, 4. achieves steady state frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	-----NOTE----- All DG starts may be preceded by an engine prelube period. ---------- Verify when started simultaneously from standby condition, each DG achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz, and b. steady state, voltage ≥ 6480 V, and ≤ 7150 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.21	Calibrate BO sequencers.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.1.22	-----NOTES----- 1. Verification of setpoint is not required. 2. Actuation of final devices is not included. ---------- Perform TADOT for SI and BO sequencers.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources -- Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem required by LCO 3.8.10, "Distribution Systems -- Shutdown"; and

b. One diesel generator (DG) capable of supplying one train of the onsite Class 1E AC electrical power distribution subsystems required by LCO 3.8.10.

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	------------------------NOTE----------------------- Enter applicable Conditions and Required Actions of LCO 3.8.10, with the required train de-energized as a result of Condition A. ---	
	A.1 Declare affected required feature(s) with no offsite power available inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	<u>AND</u>	
	A.2.4 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One required DG inoperable.	B.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	B.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	B.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	B.4 Initiate action to restore required DG to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
---NOTE--- The following SRs are not required to be performed: SR 3.8.1.3, SR 3.8.1.9 through SR 3.8.1.11, SR 3.8.1.14, SR 3.8.1.15, and SR 3.8.1.16. ---		
SR 3.8.2.1	For AC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.1.1 SR 3.8.1.5 SR 3.8.1.10 SR 3.8.1.2 SR 3.8.1.6 SR 3.8.1.11 (except c.2) SR 3.8.1.3 SR 3.8.1.7 SR 3.8.1.14 SR 3.8.1.4 SR 3.8.1.9 SR 3.8.1.15 SR 3.8.1.16	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more DGs with fuel level < a 7 day supply and > a 6 day supply in storage tank.	A.1 Restore fuel oil level to within limits.	48 hours
B. One or more DGs with lube oil inventory < a 7 day supply and > a 2 day supply.	B.1 Restore lube oil inventory to within limits.	48 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more DGs with stored fuel oil total particulates not within limit.	C.1 Restore fuel oil total particulates within limit.	7 days
D. One or more DGs with new fuel oil properties not within limits.	D.1 Restore stored fuel oil properties to within limits.	30 days
E. Required Action and associated Completion Time not met. <u>OR</u> One or more DGs diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than Condition A, B, C or D.	E.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each fuel oil storage tank contains ≥ a 7 day supply of fuel.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.2	-----------------------------------NOTE----------------------------------- Not required to be performed until the engine has been shutdown for > 10 hours. --- Verify lubricating oil inventory is ≥ a 7 day supply	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.4	Verify each required DG air start receiver pressure is ≥ 180 psig.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.3.5	Check for and remove accumulated water from each fuel oil storage tank.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources -- Operating

LCO 3.8.4 The Train A and Train B DC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two required battery chargers on one train inoperable.	A.1 Restore affected battery(ies) terminal voltage to greater than or equal to the minimum established float voltage. <u>AND</u> A.2 Verify affected battery(ies) float current $\leq$ 2 amps. <u>AND</u> A.3 Restore required battery charger(s) to OPERABLE status.	2 hours Once per 12 hours 7 days
B. One or two batteries on one train inoperable.	B.1 Restore affected battery(ies) to OPERABLE status.	2 hours
C. One DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore DC electrical power subsystem to OPERABLE status.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and Associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage is greater than or equal to the minimum established float voltage.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.4.2	Verify each battery charger supplies ≥ 300 amps at greater than or equal to the minimum established charger test voltage for ≥ 8 hours. OR Verify each battery charger can recharge the battery to the fully charged state within 24 hours while supplying the largest combined demands of the various continuous steady state loads, after a battery discharge to the bounding design basis event discharge state.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.4.3	-----NOTES----- 1. The modified performance discharge test in SR 3.8.6.6 may be performed in lieu of SR 3.8.4.3. 2. Verify requirement during MODES 3, 4, 5, 6 or with core off-loaded. ---------- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources -- Shutdown

LCO 3.8.5 The Train A or Train B DC electrical power subsystem shall be OPERABLE to support one train of the DC electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems -- Shutdown."

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required DC electrical power subsystems inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	A.2.4 Initiate action to restore required DC electrical power subsystem to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.5.1	-----------------------------------NOTE----------------------------------- The following SRs are not required to be performed: SR 3.8.4.2 and SR 3.8.4.3. ---	
	For DC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.4.1 SR 3.8.4.2 SR 3.8.4.3.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Parameters

LCO 3.8.6 Battery parameters for Train A and Train B batteries shall be within limits.

APPLICABILITY: When associated DC electrical power subsystems are required to be OPERABLE.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two batteries on one train with one or more battery cells float voltage < 2.07 V.	A.1 Perform SR 3.8.4.1	2 hours
	AND	
	A.2 Perform SR 3.8.6.1	2 hours
	AND	
	A.3 Restore affected cell(s) float voltage ≥ 2.07 V.	24 hours
B. One or two batteries on one train with float current > 2 amps.	B.1 Perform SR 3.8.4.1	2 hours
	AND	
	B.2 Restore affected battery(ies) float current to ≤ 2 amps.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------------NOTE------------ Required Action C.2 shall be completed if electrolyte level was below the top of plates. ------------------------------------ One or two batteries on one train with one or more cells electrolyte level less than minimum established design limits.	------------------------NOTE----------------------- Required Actions C.1 and C.2 are only applicable if electrolyte level was below the top of plates. --- C.1 Restore affected cell(s) electrolyte level to above the top of the plates. <u>AND</u> C.2 Verify no evidence of leakage. <u>AND</u> C.3 Restore affected cell(s) electrolyte level to greater than or equal to minimum established design limits.	 8 hours 12 hours 31 days
D. One or two batteries on one train with pilot cell electrolyte temperature less than minimum established design limits.	D.1 Restore battery pilot cell(s) electrolyte temperature to greater than or equal to minimum established design limits.	12 hours
E. One or more batteries in redundant trains with battery parameters not within limits.	E.1 Restore battery parameters for batteries in one train to within limits.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met. OR One or two batteries on one train with one or more battery cells float voltage < 2.07 V and float current > 2 amps.	F.1 Declare associated battery(ies) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	-----------------------------------NOTE----------------------------------- Not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1 --- Verify each battery float current is ≤ 2 amps.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.2	Verify each battery pilot cell voltage is ≥ 2.07 V.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3	Verify each battery connected cell electrolyte level is greater than or equal to minimum established design limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.4	Verify each battery pilot cell temperature is greater than or equal to minimum established design limits.	In accordance with the Surveillance Frequency Control Program.
SR 3.8.6.5	Verify each battery connected cell voltage is $\geq$ 2.07 V.	In accordance with the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.6.6	----------NOTE---------- Verify requirement during MODES 3, 4, 5, 6 or with core off-loaded. ------------------------------ Verify battery capacity is ≥ 80 % of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	In accordance with the Surveillance Frequency Control Program. <u>AND</u> 18 months when battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating <u>AND</u> 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters -- Operating

LCO 3.8.7 The required Train A and Train B inverters shall be OPERABLE.

--NOTE--
Inverters may be disconnected from one DC bus for ≤ 24 hours to perform an equalizing charge on their associated common battery, provided:

a. The associated AC vital bus(es) are energized; and

b. All other AC vital buses are energized from their associated OPERABLE inverters.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required inverter inoperable.	A.1 --------------------NOTE-------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any vital bus de-energized. --- Restore inverter to OPERABLE status.	 24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct inverter voltage, and alignment to required AC vital buses.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 IInverters Shutdown

LCO 3.8.8 The Train A or Train B inverters shall be OPERABLE to support one train of the onsite Class 1E AC vital bus electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems -- Shutdown."

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required inverters inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	
	A.2.4 Initiate action to restore required inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct inverter voltage and alignments to required AC vital buses.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems -- Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours
B. One AC vital bus subsystem inoperable.	B.1 Restore AC vital bus subsystem to OPERABLE status.	2 hours
C. One DC electrical power distribution subsystem inoperable.	C.1 Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours
E. Two trains with inoperable distribution subsystems that result in a loss of safety function.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program.

3.8 ELECTRICAL POWER SYSTEMS

3.8.10 Distribution Systems -- Shutdown

LCO 3.8.10 The necessary portion of the Train A or Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE to support one train of equipment required to be OPERABLE.

APPLICABILITY: MODES 5 and 6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required AC, DC, or AC vital bus electrical power distribution subsystems inoperable.	A.1 Declare associated supported required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Suspend operations involving positive reactivity additions that could result in loss of required SDM or boron concentration.	Immediately
	AND	

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate actions to restore required AC, DC, and AC vital bus electrical power distribution subsystems to OPERABLE status.	Immediately
	<u>AND</u>	
	A.2.5 Declare associated required residual heat removal subsystem(s) inoperable and not in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.10.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.1 Boron Concentration

LCO 3.9.1 Boron concentrations of all filled portions of the Reactor Coolant System, the refueling canal, and the refueling cavity, that have direct access to the reactor vessel, shall be maintained within the limit specified in the COLR.

----------NOTE----------
While this LCO is not met, entry into MODE 6 from MODE 5 is not permitted.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Boron concentration not within limit.	A.1 Suspend CORE ALTERATIONS. AND	Immediately
	A.2 Suspend positive reactivity additions. AND	Immediately
	A.3 Initiate action to restore boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Verify boron concentration is within the limit specified in the COLR.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.2 Unborated Water Source Isolation Valves

LCO 3.9.2 Each valve used to isolate unborated water sources shall be secured in the closed position.

APPLICABILITY: MODE 6.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each unborated water source isolation valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Required Action A.4 must be completed whenever Condition A is entered. ----------------------------------- One or more valves not secured in closed position.	A.1 Suspend CORE ALTERATIONS. AND A.2 Suspend positive reactivity addition. AND A.3 Initiate actions to secure valve in closed position. AND A.4 Perform SR 3.9.1.1.	Immediately Immediately Immediately 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify each valve that isolates unborated water sources is secured in the closed position.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.3 Nuclear Instrumentation

LCO 3.9.3 Two source range neutron flux monitors shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required source range neutron flux monitor inoperable.	A.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
B. Two required source range neutron flux monitors inoperable.	B.1 Initiate action to restore one source range neutron flux monitor to OPERABLE status.	Immediately
	AND	
	B.2 Perform SR 3.9.1.1.	Once per 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program.
SR 3.9.3.2	--------------------------------NOTE------------------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.4 Containment Penetrations

LCO 3.9.4 The containment penetrations shall be in the following status:

a. The equipment hatch closed and held in place by four bolts, or if open, capable of being closed;

b. One door in the emergency air lock closed and one door in the personnel airlock capable of being closed; and

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere either:

1. closed by a manual or automatic isolation valve, blind flange, or equivalent, or

2. capable of being closed by an OPERABLE containment ventilation isolation valve.

---NOTE---
Penetration flow path(s) providing direct access from the containment atmosphere to the outside atmosphere may be unisolated under administrative controls.

APPLICABILITY: During CORE ALTERATIONS,
During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment penetrations not in required status.	A.1 Suspend CORE ALTERATIONS. <u>AND</u> A.2 Suspend movement of irradiated fuel assemblies within containment.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.9.4.1	Verify each required containment penetration is in the required status.	In accordance with the Surveillance Frequency Control Program.
SR 3.9.4.2	-------------------------------NOTE------------------------------- Only required for an open equipment hatch --- Verify the capability to install the equipment hatch.	 In accordance with the Surveillance Frequency Control Program.
SR 3.9.4.3	Verify each required containment ventilation isolation valve actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.5 Residual Heat Removal (RHR) and Coolant Circulation -- High Water Level

LCO 3.9.5 One RHR loop shall be OPERABLE and in operation.

---NOTE--
The required RHR loop may be removed from operation for ≤ 1 hour per 8 hour period, provided no operations are permitted that would cause introduction of coolant into the Reactor Coolant System with boron concentration less than that required to meet the minimum required boron concentration of LCO 3.9.1.

APPLICABILITY: MODE 6 with the water level ≥ 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RHR loop requirements not met.	A.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
	AND	
	A.2 Suspend loading irradiated fuel assemblies in the core.	Immediately
	AND	
	A.3 Initiate action to satisfy RHR loop requirements.	Immediately
	AND	
	A.4 Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	Verify one RHR loop is in operation and circulating reactor coolant at a flow rate of ≥ 3800 gpm.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.6 Residual Heat Removal (RHR) and Coolant Circulation -- Low Water Level

LCO 3.9.6 Two RHR loops shall be OPERABLE, and one RHR loop shall be in operation.

---NOTE---
While this LCO is not met, entry into a MODE or other specified condition in the Applicability is not permitted.

APPLICABILITY: MODE 6 with the water level < 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Less than the required number of RHR loops OPERABLE.	A.1 Initiate action to restore required RHR loops to OPERABLE status.	Immediately
	<u>OR</u>	
	A.2 Initiate action to establish ≥ 23 ft of water above the top of reactor vessel flange.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. No RHR loop in operation.	B.1 Suspend operations that would cause introduction of coolant into the RCS with boron concentration less than required to meet the boron concentration of LCO 3.9.1.	Immediately
	AND	
	B.2 Initiate action to restore one RHR loop to operation.	Immediately
	AND	
	B.3 Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify one RHR loop is in operation and circulating reactor coolant at a flow rate of ≥ 1000 gpm.	In accordance with the Surveillance Frequency Control Program.
SR 3.9.6.2	Verify correct breaker alignment and indicated power available to the required RHR pump that is not in operation.	In accordance with the Surveillance Frequency Control Program.

3.9 REFUELING OPERATIONS

3.9.7 Refueling Cavity Water Level

LCO 3.9.7 Refueling cavity water level shall be maintained ≥ 23 ft above the top of reactor vessel flange.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refueling cavity water level not within limit.	A.1 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify refueling cavity water level is ≥ 23 ft above the top of reactor vessel flange.	In accordance with the Surveillance Frequency Control Program.

4.0 DESIGN FEATURES

4.1 Site Location

The site area is approximately 7,700 acres located in Somervell County in North Central Texas. Squaw Creek Reservoir (SCR), established for station cooling, extends into Hood County. The site is situated along Squaw Creek, a tributary of the Paluxy River, which is a tributary of the Brazos River. The site is over 30 miles southwest of the nearest portion of Fort Worth and approximately 4.5 miles north-northwest of Glen Rose, the nearest community.

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 193 fuel assemblies. Each assembly shall consist of a matrix of Zircaloy or ZIRLO™ clad fuel rods with an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing or that contain Westinghouse ZIRLO™ fuel rod cladding may be placed in non-limiting core regions.

4.2.2 Control Rod Assemblies

The reactor core shall contain 53 control rod assemblies. The control material shall be silver-indium-cadmium as approved by the NRC.

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent;

b. k_{eff} < 1.0 when fully flooded with unborated water which includes an allowance for uncertainties as described in Section 4.3 of the FSAR;

c. $k_{eff} \leq 0.95$ if fully flooded with water borated to 400 ppm, which includes an allowance for uncertainties as described in Section 4.3 of the FSAR;

d. A nominal 9 inch center to center distance between fuel storage locations in Region II fuel storage racks;

e. A nominal 10.65 inch by nominal 11.05 inch center to center distance between fuel assemblies placed in Region I fuel storage racks;

f. New or partially spent fuel assemblies may be allowed restricted storage in a 1 out of 4 configuration in Region II fuel storage racks (as shown in Figure 3.7.17-1, Array II-E) or unrestricted storage in Region I fuel storage racks;

g. Storage of new or spent fuel assemblies in Region II storage racks must comply with 3.7.17 Spent Fuel Assembly Storage.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent;

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 4.3 of the FSAR;

c. $k_{eff} \leq 0.98$ if moderated by aqueous foam, which includes an allowance for uncertainties as described in Section 4.3 of the FSAR; and

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

d. A nominal 21 inch center to center distance between fuel assemblies placed in the storage racks.

4.3.2 Drainage

The spent fuel storage pools are designed and shall be maintained to prevent inadvertent draining of the pool below elevation 854 ft.

4.3.3 Capacity

The spent fuel storage pools are designed and shall be maintained with a storage capacity limited to no more than 3373 fuel assemblies.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The Plant Manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

The Plant Manager or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.

5.1.2 The Shift Manager shall be responsible for the control room command function. During any absence of the Shift Manager from the control room while the unit is in MODE 1, 2, 3, or 4, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the Shift Manager from the control room while the unit is in MODE 5 or 6, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements including the plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be documented in the FSAR;

b. The Plant Manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. A specified corporate officer shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A non-licensed operator shall be assigned to each reactor containing fuel and an additional non-licensed operator shall be assigned if either unit is operating in MODES 1, 2, 3, or 4.

   With both units shutdown or defueled, a total of three non-licensed operators for the two units is required.

5.2 Organization

5.2.2 Unit Staff (continued)

b. Shift crew composition may be one less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.e for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. --- NOTE ---

A single Radiation Protection Technician and a single Chemistry Technician may fulfill the requirements for both units.

A Radiation Protection Technician and Chemistry Technician shall be on site when fuel is in the reactor. The positions may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required positions.

d. The Shift Operations Manager shall hold an SRO license.

e. An individual shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This shall be assigned to both units when either unit is in MODE 1, 2, 3, or 4. The STA position may be filled by the shift manager or an on-shift SRO providing the individuals meet the dual role qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

5.3.1 Each member of the unit staff, with the exception of licensed Senior Reactor Operators (SRO) and licensed Reactor Operators (RO), shall meet or exceed the minimum qualifications of Regulatory Guide 1.8, Revision 2, 1987.

5.3.2 Licensed Senior Reactor Operators (SRO) and licensed Reactor Operators (RO) shall meet or exceed the minimum qualifications of Regulatory Guide 1.8, Revision 3, May 2000.

5.3.3 For the purposes of 10CFR55.4, a licensed Senior Reactor Operator (SRO) and a licensed reactor operator (RO) are those individuals who, in addition to meeting the requirements of TS 5.3.2, perform the functions described in 10CFR50.54(m).

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program implementation; and

e. All programs specified in Specification 5.5.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities, and descriptions of the information that should be included in the Annual Radiological Environmental Operating, and Radioactive Effluent Release Report required by Specification 5.6.2 and Specification 5.6.3.

c. Licensee initiated changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   i. sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   ii. a determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

2. Shall become effective after the approval of the Plant Manager; and

3. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5 Programs and Manuals (continued)

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The systems include the post accident recirculation portion of the Containment Spray System, Safety Injection System, Chemical and Volume Control System, RHR System and RCS Sampling System (Post Accident Sampling System portion only until such time as a modification eliminates the PASS penetration as a potential leakage path). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.3 Not Used

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to 10 times the concentration values in Appendix B, Table 2, Column 2, to 10 CFR 20.1001 - 20.2402;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days;

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the site boundary shall be in accordance with the following:

1. For noble gases: a dose rate of ≤ 500 mrem/yr to the total body and a dose rate of ≤ 3000 mrem/yr to the skin, and

2. For iodine-131, for iodine-133, for tritium, and for all radionuclides in particulate form with half lives greater than 8 days: a dose rate ≤ 1500 mrem/yr to any organ.

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public, beyond the site boundary, from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

k. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Radioactive Effluent Controls program surveillance frequency.

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track the FSAR, Section 3.9N, cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.6 Not used

5.5 Programs and Manuals (continued)

5.5.7 Reactor Coolant Pump Flywheel Inspection Program

This program shall provide for the inspection of each reactor coolant pump flywheel per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975. In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals.

5.5.8 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program shall include the following:

a. Testing frequencies applicable to the ASME Code for Operations and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as follows:

ASME OM Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies and to other normal and accelerated Frequencies specified as 2 years or less in the Inservice Testing Program for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME OM Code shall be construed to supersede the requirements of any TS.

5.5 Programs and Manuals (continued)

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the “as found” condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The “as-found” condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down), all anticipated transients included in the design specification, and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, “RCS Operational LEAKAGE.”

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

1. The following alternate tube plugging criteria shall be applied as an alternative to the 40% depth based criteria:

a. For Unit 2 only, tubes with service-induced flaws located greater than 14.01 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 14.01 inches below the top of the tubesheet shall be plugged upon detection.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. For Unit 1, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria. For Unit 2, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side and that may satisfy the applicable tube plugging criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements below, the inspection scope, inspection methods and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

2. For the Unit 2 model D5 steam generators (Alloy 600 thermally treated) after the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

b. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

c. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

3. For the Unit 1 model Delta-76 steam generators (Alloy 690 thermally treated) after the first refueling outage following SG installation, inspect each SG at least every 72 effective full power months or at least every third refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, c and d below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the

5.5 Programs and Manuals

5.5.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator (SG) Program (continued)

inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a. After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b. During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;

c. During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and

d. During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.

4. For Unit 1, if crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indications shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). For Unit 2, if crack indications are found in any SG tube from 14.01 inches below the top of the tubesheet on the hot leg side to 14.01 inches below the top of the tubesheet on the cold leg side, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indications shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5 Programs and Manuals (continued)

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 2 and in accordance with Regulatory Guide 1.52, Revision 2, ANSI/ASME N509-1980, ANSI/ASME N510-1980, and ASTM D3803-1989.

--NOTE--
ANSI/ASME N510-1980, ANSI/ASME N509-1980, and ASTM D3803-1989 shall be used in place of ANSI 510-1975, ANSI/ASME N509-1976, and ASTM D3803-1979 respectively in complying with Regulatory Guide 1.52, Revision 2.
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a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass < 1.0% for Primary Plant Ventilation System - ESF Filtration units and < 0.05% for all other units when tested in accordance with Regulatory

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate
Control Room Emergency filtration unit	8,000 CFM
Control Room Emergency pressurization unit	800 CFM
Primary Plant Ventilation System – ESF filtration unit	15,000 CFM

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 1.0% for Primary Plant Ventilation System - ESF Filtration units and < 0.05% for all other units when tested in accordance with Regulatory Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%.

ESF Ventilation System	Flowrate
Control Room Emergency filtration unit	8,000 CFM
Control Room Emergency pressurization unit	800 CFM
Primary Plant Ventilation System - ESF filtration unit	15,000 CFM

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of ≤ 30°C and greater than or equal to the relative humidity specified below.

ESF Ventilation Systems	Penetration	RH
Control Room Emergency filtration unit	0.5%	70%
Control Room Emergency pressurization unit	0.5%	70%
Primary Plant Ventilation System – ESF filtration unit	2.5%	70%

d. Demonstrate at least once per 18 months for each of the ESF systems that the pressure drop across the combined HEPA filters, the prefilters, and the charcoal adsorbers is less than the value specified below when tested in

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

accordance with Regulatory Guide 1.52, Revision 2, and ANSI/ASME N510-1980 at the system flowrate specified below ± 10%

ESF Ventilation System	Delta P	Flowrate
Control Room Emergency filtration unit	8.0 in WG	8000 CFM
Control Room Emergency pressurization unit	9.5 in WG	800 CFM
Primary Plant Ventilation System – ESF filtration unit.	8.5 in WG	15000 CFM

e. Demonstrate at least once per 18 months that the heaters for each of the ESF systems dissipate the value specified below when tested in accordance with ANSI/ASME N510-1980.

ESF Ventilation System	Wattage
Control Room Emergency pressurization unit	10 ± 1 kW
Primary Plant Ventilation System - ESF filtration unit	100 ± 5 kW

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Gaseous Waste Processing System, the quantity of radioactivity contained in each Gas Decay Tank, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks.

The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure," Revision 0, July 1981. The liquid radwaste quantities shall be determined in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures," Revision 2, July 1981.

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Gaseous Waste Processing System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

5.5 Programs and Manuals

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

b. A surveillance program to ensure that the quantity of radioactivity contained in each Gas Decay Tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents; and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than the amount that would result in concentrations less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2 to 10 CFR 20.1001 - 20.2402, at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

d. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.13 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. an API gravity or an absolute specific gravity within limits,

2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

3. a clear and bright appearance with proper color or a water and sediment content within limits.

b. Within 31 days following addition of the new fuel oil to the storage tanks, verify that the properties of the new fuel oil, other than those addressed in a., above, are within limits for ASTM 2D fuel oil, and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program.

5.5 Programs and Manuals (continued)

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. a change in the TS incorporated in the license; or

2. a change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of Specification 5.5.14b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e) and exemptions thereto.

5.5.15 Safety Function Determination Program (SFDP)

a. This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

1. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

2. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

3. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

4. Other appropriate limitations and remedial or compensatory actions.

5.5 Programs and Manuals

5.5.15 Safety Function Determination Program (SFDP) (continued)

b. A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

1. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

2. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

3. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

c. The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," Revision 3-A, dated July 2012, and the conditions and limitations specified in NEI 94-01, Revision 2-A, dated October 2008, as modified by the following exceptions:

1. The visual examination of containment concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

2. The visual examination of the steel liner plate inside containment intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B, will be performed in accordance with the requirements of and frequency specified by the ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

5.5 Programs and Manuals

5.5.16 Containment Leakage Rate Testing Program (continued)

b. The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 48.3 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

d. Leakage rate acceptance criteria are:

1. Containment leakage rate acceptance criteria is $\leq$ 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are < 0.60 L_a for the Type B and Type C tests and $\leq$ 0.75 L_a for Type A tests;

2. Air lock testing acceptance criteria are:

i. Overall air lock leakage rate is $\leq$ 0.05 L_a when tested at $\geq P_a$.

ii. For each door, leakage rate is $\leq$ 0.01 L_a when pressurized to $\geq P_a$.

e. The provision of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program, with the exception of the containment ventilation isolation valves.

f. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.5.17 Technical Requirements Manual (TRM)

The TRM contains selected requirements which do not meet the criteria for inclusion in the Technical Specification but are important to the operation of CPNPP. Much of the information in the TRM was relocated from the TS.

Changes to the TRM shall be made under appropriate administrative controls and reviews. Changes may be made to the TRM without prior NRC approval provided the changes do not require either a change to the TS or NRC approval pursuant to 10 CFR 50.59. TRM changes require approval of the Plant Manager.

5.5.18 Configuration Risk Management Program (CRMP)

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for

5.5 Programs and Manuals

5.5.18 Configuration Risk Management Program (CRMP) (continued)

which a risk-informed Completion Time has been granted. The program shall include the following elements:

a. Provisions for the control and implementation of a Level 1, at-power, internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Action for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Action for unplanned entry into the LCO Action.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Action.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues, and external events, qualitatively or quantitatively.

5.5.19 Battery Monitoring and Maintenance Program

This Program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," or of the battery manufacturer for the following:

a. Actions to restore battery cells with float voltage < 2.13 V, and

b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates.

5.5.20 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Filtration System (CREFS), CRE occupants can control the reactor safety under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem whole body or its equivalent to any part of the body for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

5.5 Programs and Manuals

5.5.20 Control Room Envelope Habitability Program (continued)

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, “Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors,” Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

   The following are exceptions to Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0:

   1. C. - Section 4.3.2 “Periodic CRH Assessment” from NEI 99-03 Revision 1 will be used as input to a site specific Self Assessment procedure.

   2. C.1.2 - No peer reviews are required to be performed.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREFS, operating at the flow rate required by the VFTP, at a Frequency of 18 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 18 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.5 Programs and Manuals

5.5.21 Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI-04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 1.

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

5.5.22 Spent Fuel Storage Rack Neutron Absorber Monitoring Program

The Region I storage cells in the CPNPP Spent Fuel Pool utilize the neutron absorbing material BORAL, which is credited in the Safety Analysis to ensure the limitations of Technical Specification 4.3.1.1 are maintained.

In order to ensure the reliability of the Neutron Poison material, a monitoring program is required to routinely confirm that the assumptions utilized in the criticality analysis remain valid and bounding. The Neutron Absorber Monitoring Program is established to monitor the integrity of neutron absorber test coupons periodically as described below.

A test coupon "tree" shall be maintained in each SFP. Each coupon tree originally contained 8 neutron absorber surveillance coupons. Detailed measurements were taken on each of these 16 coupons prior to installation, including weight, length, width, thickness at several measurement locations, and B-10 content (g/cm^2). These coupons shall be maintained in the SFP to ensure they are exposed to the same environmental conditions as the neutron absorbers installed in the Region I storage cells, until they are removed for analysis.

One test coupon from each SFP shall be periodically removed and analyzed for potential degradation, per the following schedule. The schedule is established to ensure adequate coupons are available for the planned life of the storage racks.

5.5 Programs and Manuals

5.5.22 Spent Fuel Storage Rack Neutron Absorber Monitoring Program (continued)

Year	Coupon Number	Year	Coupon Number
2013	1	2028	5
2015	2	2033	6
2018	3	2043	7
2023	4	2053	8

Further evaluation of the absorber materials, including an investigation into the degradation and potential impacts on the Criticality Safety Analysis, is required if:

- A decrease of more than 5% in B-10 content from the initial value is observed in any test coupon as determined by neutron attenuation.
- An increase in thickness at any point is greater than 25% of the initial thickness at that point.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Deleted

5.6.2 Annual Radiological Environmental Operating Report

---NOTE---
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 1 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in a format similar to the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Effluent Release Report

---NOTE---
A single submittal may be made for a multiple unit station. The submittal shall combine sections common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

The Radioactive Effluent Release Report covering the operation of the unit during the previous year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I, Section IV.B.1.

5.6.4 Deleted

5.6 Reporting Requirements (continued)

5.6.5 Core Operating Limits Report (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. Moderator temperature coefficient limits for Specification 3.1.3.

2. Shutdown Rod Insertion Limit for Specification 3.1.5.

3. Control Rod Insertion Limits for Specification 3.1.6.

4. AXIAL FLUX DIFFERENCE Limits and target band for Specification 3.2.3.

5. Heat Flux Hot Channel Factor, K(Z), W(Z), F_Q^{RTP}, and the $F_Q^{c}(Z)$ allowances for Specification 3.2.1.

6. Nuclear Enthalpy Rise Hot Channel Factor Limit and the Power Factor Multiplier for Specification 3.2.2.

7. SHUTDOWN MARGIN values in Specifications 3.1.1, 3.1.4, 3.1.5, 3.1.6 and 3.1.8.

8. Refueling Boron Concentration limits in Specification 3.9.1.

9. Overtemperature N-16 Trip Setpoint in Specification 3.3.1.

10. Reactor Coolant System pressure, temperature, and flow in Specification 3.4.1.

11. Reactor Core Safety Limit (Safety Limit 2.1.1).

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC. When an initial assumed power level of 102 percent of rated power is specified in a previously approved method, 100.6 percent of rated power may be used only when feedwater flow measurement (used as input for reactor thermal power measurement) is provided by the leading edge flowmeter (LEFM√) as described in document number 3 listed below. When feedwater flow measurements from the LEFM√ are not available, the originally approved initial power level of 102 percent of rated thermal power shall be used.

5.6 Reporting Requirements

5.6.5 Core Operating Limits Report (COLR) (continued)

Future revisions of approved analytical methods listed in this technical specification that currently assume 102 percent of rated power shall include the condition given above allowing use of 100.6 percent of rated power in safety analysis methodology when the LEFM√ is used for feedwater flow measurement.

The approved analytical methods are described in the following documents:

1. WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (W Proprietary).

2. WCAP-10216-P-A, Revision 1A, “RELAXATION OF CONSTANT AXIAL OFFSET CONTROL F_Q SURVEILLANCE TECHNICAL SPECIFICATION,” February 1994 (W Proprietary).

3. Caldon, Inc. Engineering Report-80P, “Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power level Using the LEFM√ System,” Revision 0, March 1997 and Caldon Engineering Report – 160P, “Supplement to Topical Report ER-80P; Basis for a Power Uprate With the LEFM√^{tm} System,” Revision 0, May 2000.

4. WCAP-10444-P-A, “Reference Core Report VANTAGE 5 Fuel Assembly,” September 1985.

5. WCAP-15025-P-A, “Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles for Modified LPD Mixing Vane Grids,” April 1999.

6. WCAP-10360-P-A, “Westinghouse Fuel Assembly Reconstitution Evaluation Methodology,” July, 1993.

7. WCAP-11397-P-A, “Revised Thermal Design Procedure,” April 1989.

8. WCAP-8745-P-A, “Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions,” September 1986.

9. WCAP-14565-P-A, “VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis,” October 1999.

10. WCAP-14882-P-A, “RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses,” April 1999.

5.6 Reporting Requirements

5.6.5 Core Operating Limits Report (COLR) (continued)

11. WCAP-10054-P-A, “Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code,” August 1985.

12. WCAP-10054-P-A, Addendum 2, Revision 1, “Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model,” July 1997.

13. WCAP-10079-P-A, “NOTRUMP, A Nodal Transient Small Break and General Network Code,” August 1985.

14. WCAP-16009-P-A, “Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM),” January 2005.

15. WCAP-12472-P-A, “BEACON Core Monitoring and Operations Support System,” August 1994.

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing, and PORV lift settings as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

1. Specification 3.4.3, “RCS Pressure and Temperature (P/T) Limits,” and

2. Specification 3.4.12, “Low Temperature Overpressure Protection (LTOP) System.”

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (continued)

1. WCAP-14040-NP-A; "Methodology used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves."

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.6.7 Not used

5.6.8 PAM Report

When a report is required by the required actions of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each degradation mechanism,

f. The number and precentage of tubes plugged to date, and the effective plugging percentage in each steam generator,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing,

h. For Unit 2, the primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to

5.6 Reporting Requirements

5.6.9 Unit 1 Model D76 and Unit 2 Model D5 Steam Generator Tube Inspection Report (continued)

secondary leakage should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,

i. For Unit 2, the calculated accident induced leakage rate from the portion of the tubes below 14.01 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 3.16 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

j. For Unit 2, the results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601(a) and (b) of 10 CFR Part 20:

5.7.1 High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation:

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment.

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area; or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously, transmits dose rate information and cumulative dose to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure with the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

i. Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

5.7 High Radiation Area

5.7.1 High Radiation Areas with Dose Rates not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation (continued)

ii. Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation:

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the [shift manager], or his or her designee.

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation: (continued)

1. A radiation monitoring device that continuously integrates the radiation rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and,

   i. Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

   ii. Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area.

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the Low As is Reasonably Achievable principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

e. Except for individuals qualified in radiation protection procedures or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them. These continuously escorted personnel will receive a pre-job briefing prior to entry into such areas. This dose rate determination, knowledge, and pre-job briefing does not require documentation prior to initial entry.

f. Such individual areas that are within a larger area , such as PWR containment, where no enclosure exists for the purpose of locking and where

5.7 High Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation: (continued)

no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

TS EFFECTIVE PAGE LISTING

Amendment Record:

Amendment No. 64	July 27, 1999
Amendment No. 65	July 27, 1999
Amendment No. 66	August 31, 1999
Amendment No. 67	September 29, 1999
Amendment No. 68	September 29, 1999
Amendment No. 69	September 30, 1999
Amendment No. 70	September 30, 1999
Amendment No. 71	September 30, 1999
Amendment No. 72	October 7, 1999
Amendment No. 73	December 30, 1999
Amendment No. 74	December 31, 1999
Amendment No. 75	April 23, 2000
Amendment No. 76	April 23, 2000
Amendment No. 77	May 26, 2000
Amendment No. 78	June 29, 2000
Amendment No. 79	September 19, 2000
Amendment No. 80	October 12, 2000
Amendment No. 81	December 8, 2000
Amendment No. 82	Security Plan
Amendment No. 83	March 19, 2001
Amendment No. 84	April 18, 2001
Amendment No. 85	May 18, 2001
Amendment No. 86	July 17, 2001
Amendment No. 87	January 3, 2002
Amendment No. 88	November 1, 2001
Amendment No. 89	October 16, 2001
Amendment No. 90	Operating License
Amendment No. 91	March 13, 2003
Amendment No. 92	March 25, 2002
Amendment No. 93	March 25, 2002
Amendment No. 94	Operating License
Amendment No. 95	April 8, 2002
Amendment No. 96	July 24, 2002
Amendment No. 97	August 15, 2002
Amendment No. 98	October 8, 2002
Amendment No. 99	September 24, 2002
Amendment No. 100	September 24, 2002
Amendment No. 101	October 8, 2002
Amendment No. 102	February 28, 2003
Amendment No. 103	January 15, 2004
Amendment No. 104	Operating License
Amendment No. 105	August 21, 2003
Amendment No. 106	September 18, 2003
Amendment No. 107	TS Bases Revision 31 & FSAR
Amendment No. 108	October 2, 2003
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Amendment No. 113	August 26, 2004
Amendment No. 114	April 7, 2005
Amendment No. 115	April 7, 2005
Amendment No. 116	June 2, 2005
Amendment No. 117	August 4, 2005
Amendment No. 118	August 4, 2005
Amendment No. 119	August 4, 2005
Amendment No. 120	September 22, 2005
Amendment No. 121	December 8, 2005
Amendment No. 122	November 3, 2005
Amendment No. 123	October 11, 2005 (Unit 1)
Amendment No. 123	March 30, 2006 (Unit 2)
Amendment No. 124	April 24, 2006
Amendment No. 125	April 17, 2006
Amendment No. 126	June 15, 2006
Amendment No. 127	November 16, 2006
Amendment No. 128	October 4, 2006
Amendment No. 129	October 17, 2006
Amendment No. 130	Operating License & FSAR
Amendment No. 131	March 30, 2007
Amendment No. 132	March 30, 2007
Amendment No. 133	June 21, 2007
Amendment No. 134	June 21, 2007
Amendment No. 135	March 30, 2007
Amendment No. 136	April 11, 2007
Amendment No. 137	July 24, 2007
Amendment No. 138	July 24, 2007
Amendment No. 139	Operating License
Amendment No. 140	February 28, 2008
Amendment No. 141	February 28, 2008
Amendment No. 142	February 28, 2008
Amendment No. 143	Operating License
Amendment No. 144	April 4, 2008
Amendment No. 145	April 4, 2008
Amendment No. 146	September 11, 2008
Amendment No. 147	November 13, 2008
Amendment No. 148	October 1, 2009
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Amendment No. 163	OL Change Only
Amendment No. 164	April 2, 2015
Amendment No. 165	April 14, 2016

(continued)

(continued)

(continued)

CR A/C SYSTEM DATA SHEET

STEP		OBSERVED	REQUIRED TEST CONDITIONS	INITIALS
6.0	PREREQUISITES MET	N/A	N/A	JR
	AND TIME/DATE	1 hour ago/Today	N/A	JR
8.1	CR A/C UNITS BEING TESTED	3 & 4	N/A	JR
8.2	TIME AND DATE	Now/Today	≥30 MIN PAST STEP 6.0	JR
8.3	RECORD THE FOLLOWING:			
	• X-TR-4123 OUTSIDE TEMPERATURE	______	N/A	______
	• X-TI-5933	______	≥60°F	______
	• X-TI-5734	______	≥60°F	______
	• X-TI-5735	______	≥60°F	______
	• COMPRESSOR DISCHARGE PRESSURES (N/A for shutdown units)			
	CR A/C UNIT 01 (X-PI-3583A)	______	<170 PSIG	______
	CR A/C UNIT 02 (X-PI-3584A)	______	<170 PSIG	______
	CR A/C UNIT 03 (X-PI-3585A)	______	<170 PSIG	______
	CR A/C UNIT 04 (X-PI-3586A)	______	<170 PSIG	______
8.4	ALL ABOVE REQUIRED TEST CONDITIONS MET	N/A	NOTE 1	______

NOTE 1: If test conditions are not met, TERMINATE test at this point. Test shall be restarted when conditions can be met.

CR A/C SYSTEM DATA SHEET

STEP		OBSERVED	INITIALS
8.5	A/C UNIT % UNLOADED (N/A for shutdown units)		
	A/C UNIT 01	________	________
	A/C UNIT 02	________	________
	A/C UNIT 03	________	________
	A/C UNIT 04	________	________
8.6	CALCULATE AVERAGE		
	A/C UNIT NO.________ A/C UNIT NO.________		
	% UNLOADED________ + % UNLOADED________ 2	= ____________ TRAIN AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY	________ ________ VERIFIED
8.7	COMPARE OUTSIDE TEMP (STEP 8.3) AND AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY (STEP 8.6) TO CURVE (FIGURE 1)	OPERATION ABOVE/BELOW CURVE	________
	ACCEPTANCE CRITERIA SAT IF OPERATION IS ABOVE CURVE	SAT/UNSAT	________

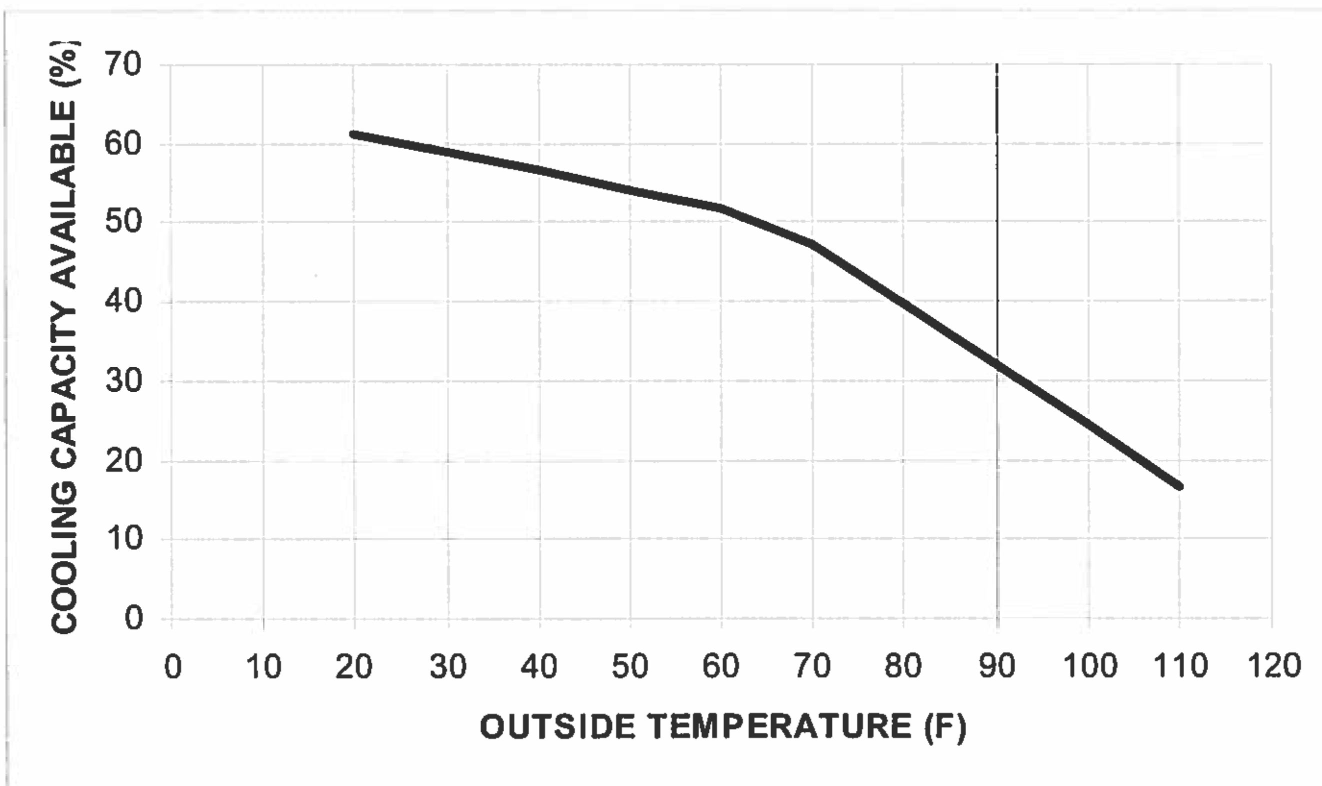
CR A/C SYSTEM DATA SHEET

FIGURE 1

OUTSIDE TEMPERATURE	PERCENT UNLOADED
	16.7
110	24.3
100	32.0
90	39.6
80	47.2
70	51.7
60	54.1
50	56.5
40	58.9
30	61.3
20	

CONTROL ROOM HVAC MINIMUM REQUIRED AVAILABILITY

THE UNLOADED COMBINED AVERAGE OF THE TWO 50% CONTROL ROOM HVAC UNITS MUST BE ABOVE THE CURVE REPRESENTED BELOW:



CR A/C SYSTEM DATA SHEET

COMMENTS/DISCREPANCIES:____

____

____

____

____

____

CORRECTIVE ACTIONS:____

____

____

____

____

____

PERFORMED BY:_________________________________DATE:_______________
SIGNATURE

REVIEWED BY:__________________________________DATE:_______________
OPERATIONS MANAGEMENT

Initial Conditions: **Given the following conditions:**

- **Both Units are operating at 100% power with all controls in Automatic.**
- **Train B Control Room Air Conditioning System is being tested per OPT-116, CR AC SYSTEM**
- **The 30 minute run time since completion of the Prerequisites is complete.**
- **The following parameters are observed:**
  - **CR A/C UNIT 03- X-PI-3585A reads 150 psig and is operating 45% unloaded**
  - **CR A/C UNIT 04 -X-PI-3586A reads 160 psig and is operating 35% unloaded**
  - **X-TR-4123 reads 75°F**
  - **X-TI-5933 reads 63°F**
  - **X-TI-5734 reads 64°F**
  - **X-TI-5735 reads 62°F**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **COMPLETE the Control Room Air Conditioning System surveillance per OPT-116, CR AC SYSTEM**
- **RECORD and COMPLETE all data on OPT-116-1, CR AC System Data Sheet**
- **If required, IDENTIFY any Technical Specification LCO CONDITION, REQUIRED ACTION, and COMPLETION TIME and record in Comments Section of surveillance**

Technical Specification LCO 3.7.11, CRACS

CONDITION A – One CRAC train inoperable

REQUIRED ACTION A.1 – Restore CRAC train to OPERABLE status

COMPLETION TIME – within 30 days

CR A/C SYSTEM DATA SHEET

STEP		OBSERVED	REQUIRED TEST CONDITIONS	INITIALS
6.0	PREREQUISITES MET	N/A	N/A	JR
	AND TIME/DATE	1 hour ago/Today	N/A	JR
8.1	CR A/C UNITS BEING TESTED	3 & 4	N/A	JR
8.2	TIME AND DATE	Now/Today	≥30 MIN PAST STEP 6.0	JR
8.3	RECORD THE FOLLOWING:			
	• X-TR-4123 OUTSIDE TEMPERATURE	75	N/A	
	• X-TI-5933	63	≥60°F	
	• X-TI-5734	64	≥60°F	
	• X-TI-5735	62	≥60°F	
	• COMPRESSOR DISCHARGE PRESSURES (N/A for shutdown units)			
	CR A/C UNIT 01 (X-PI-3583A)	N/A	<170 PSIG	
	CR A/C UNIT 02 (X-PI-3584A)	N/A	<170 PSIG	
	CR A/C UNIT 03 (X-PI-3585A)	150	<170 PSIG	
	CR A/C UNIT 04 (X-PI-3586A)	160	<170 PSIG	
8.4	ALL ABOVE REQUIRED TEST CONDITIONS MET	N/A	NOTE 1	Initials

NOTE 1: If test conditions are not met, TERMINATE test at this point. Test shall be restarted when conditions can be met.

CR A/C SYSTEM DATA SHEET

STEP		OBSERVED	INITIALS
8.5	A/C UNIT % UNLOADED (N/A for shutdown units)		
	A/C UNIT 01	N/A	______
	A/C UNIT 02	N/A	______
	A/C UNIT 03	45%	______
	A/C UNIT 04	35%	______
8.6	CALCULATE AVERAGE A/C UNIT NO. 3 A/C UNIT NO. 4 % UNLOADED 45 + % UNLOADED 35 / 2	= 40 TRAIN AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY	Perform Step 7 Cue VERIFIED
8.7	COMPARE OUTSIDE TEMP (STEP 8.3) AND AVERAGE COMPRESSOR COOLING CAPACITY AVAILABILITY (STEP 8.6) TO CURVE (FIGURE 1)	OPERATION ABOVE/BELOW CURVE	______
	ACCEPTANCE CRITERIA SAT IF OPERATION IS ABOVE CURVE	SAT/UNSAT	______

CPNPP 2017 NRC ADMIN JPM SA3 Key

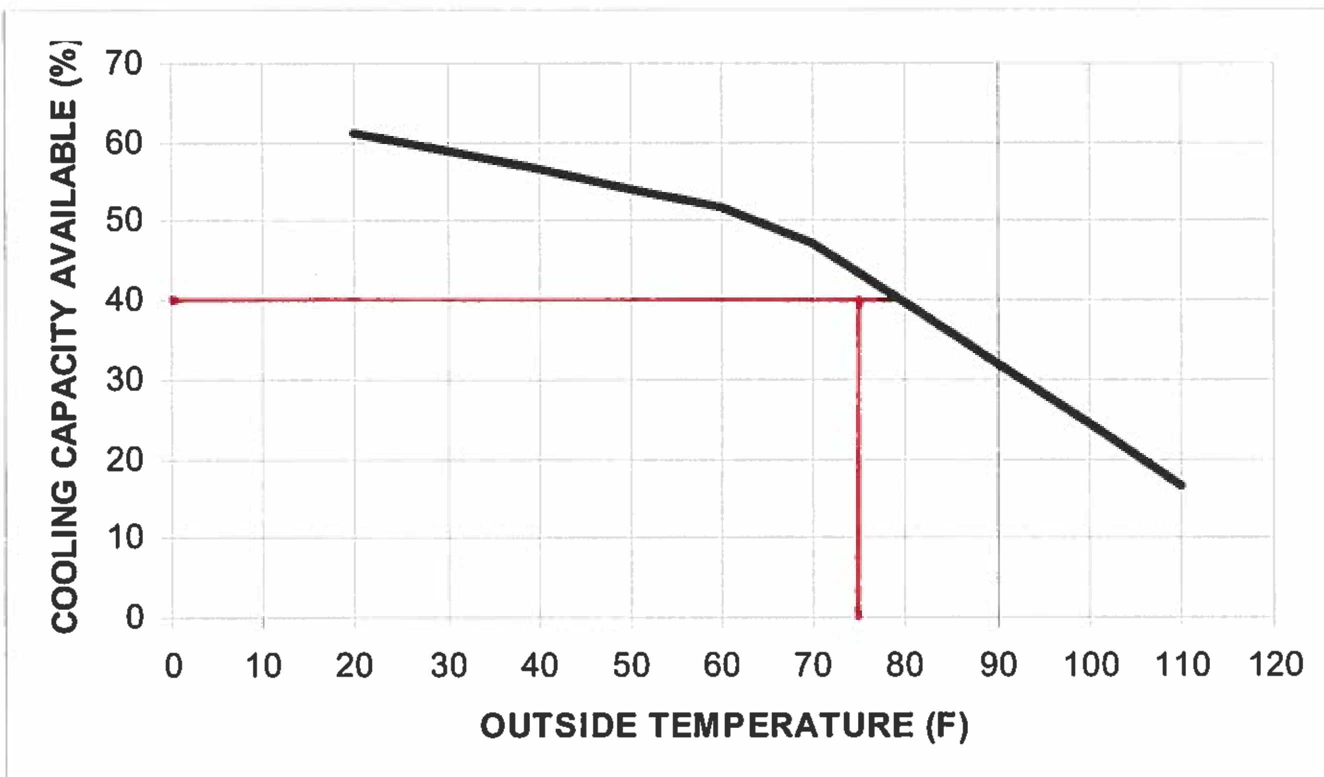
CR A/C SYSTEM DATA SHEET

FIGURE 1

OUTSIDE TEMPERATURE	PERCENT UNLOADED
	16.7
110	24.3
100	32.0
90	39.6
80	47.2
70	51.7
60	54.1
50	56.5
40	58.9
30	61.3
20	

CONTROL ROOM HVAC MINIMUM REQUIRED AVAILABILITY

THE UNLOADED COMBINED AVERAGE OF THE TWO 50% CONTROL ROOM HVAC UNITS MUST BE ABOVE THE CURVE REPRESENTED BELOW:



CR A/C SYSTEM DATA SHEET

COMMENTS/DISCREPANCIES:

CORRECTIVE ACTIONS:

PERFORMED BY: ______________________ DATE: __________
SIGNATURE

REVIEWED BY: ______________________ DATE: __________
OPERATIONS MANAGEMENT

CPNPP 2017 NRC ADMIN JPM SA3 Key

Facility: CPNPP JPM # NRC SA4 Task # SO1112B K/A # 2.3.12 3.2 / 3.7

Title: Determine Radiation Levels and Reporting Requirements

Examinee (Print): ________________________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: JPM Cue Sheet #1

Given the following conditions:

- A high dose maintenance activity is scheduled in the Fuel Building
- The general dose rate in the area is 100 mrem / hour but can be reduced to 25 mrem / hour if lead shielding is installed
- It will take NEOs A & B 30 minutes to install the shielding
- Independent of the shielding, it will take NEO A 2 hours or NEOs A & B 1.5 hours to perform the maintenance

Initiating Cue:

The Work Control Supervisor directs you to PERFORM the following:

- CALCULATE the dose received when performing the maintenance for each of the following conditions:
  - NEO A without shielding. __________ mrem
  - NEOs A & B without shielding. __________ mrem
  - NEO A with shielding. __________ mrem
  - NEOs A & B with shielding. __________ mrem

Initial Conditions: JPM Cue Sheet #2

Given the following conditions:

- The Shift Manager was notified by Radiation Protection that an individual handling radioactive licensed material received 5.5 REM TEDE in a 3 hour period

Initiating Cue:

The Shift Manager directs you to PERFORM the following:

- DETERMINE Oral and Written Reportability Requirements, if any
  - Oral Reporting Requirement ______________
  - Written Reporting Requirement ______________

Task Standard:

UTILIZED STA-657, CALCULATED the dose received when performing maintenance. UTILIZED STA-501, DETERMINED Oral and Written Reporting Requirements for an overexposure event.

Ref. Materials: STA-657, ALARA Job Planning/Debriefing, Rev. 19.
STA-501, Nonroutine Reporting, Rev. 21.

Validation Time: 25 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ____ Date: ________________

CLASSROOM SETUP

EXAMINER:

PROVIDE the examinee JPM Cue Sheet #1.

When JPM Cue Sheet #1 is completed, PROVIDE JPM Cue Sheet #2.

PROVIDE the examinee with a copy of:

- **STA-657, ALARA Job Planning/Debriefing (Procedure 1)**
- **STA-501, Nonroutine Reporting Rev. 21 (Procedure 2)**

√ - Check Mark Denotes Critical Step

START TIME:	

Perform Step: 1√	DETERMINE total dose to NEO Alpha <u>without</u> shielding.
Standard:	DETERMINED total dose to NEO Alpha <u>without</u> shielding as follows: • 100 mrem/hr x 2 hours = 200 mrem total dose
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2√	DETERMINE total combined dose to NEOs Alpha & Bravo <u>without</u> shielding.
Standard:	DETERMINED total combined dose to NEOs Alpha & Bravo <u>without</u> shielding as follows: • 100 mrem/hr x 1.5 hours/NEO x 2 NEOs = 300 mrem total dose
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3	DETERMINE total dose to <u>install</u> shielding.
Standard:	DETERMINED total dose to <u>install</u> shielding as follows: • 100 mrem/hr x 0.5 hours/NEO x 2 NEOs = 100 mrem to install
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4√	DETERMINE total dose to NEO Alpha <u>with</u> shielding.
Standard:	DETERMINED total dose to NEO Alpha <u>with</u> shielding as follows: • 25 mrem/hr x 2 hours =50 mrem + 50 mrem received while installing shielding = 100 mrem total dose
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 5√	DETERMINE total combined dose to NEOs Alpha & Bravo <u>with</u> shielding.
Standard:	DETERMINED total combined dose to NEOs Alpha & Bravo <u>with</u> shielding as follows: • 25 mrem/hr x 1.5 hours/NEO x 2 NEOs + 100 mrem = 175 mrem total dose
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**Provide the examinee with copy of JPM Cue Sheet #2.**
Examiner Note:	**The following steps are from STA-501, Attachment 8.D/4.**
Perform Step: 6√ Attachment 8.D/4 Page 7 of 12	DETERMINE Oral Reporting Requirements per STA-501.
Standard:	DETERMINED Oral Reporting Requirements per STA-501. Attachment 8.D/4 page 7 of 12: "Any event involving licensed material possessed that may have caused or threatens to cause exposure to individual: ≥ 5 rems TEDE" • Oral Report within 24 hours via ENS
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 7√ Attachment 8.D/4 Page 7 of 12	DETERMINE Written Reporting Requirements per STA-501.
Standard:	DETERMINED Oral Reporting Requirements per STA-501. Attachment 8.D/4 page 7 of 12: "Any event involving licensed material possessed that may have caused or threatens to cause exposure to individual: ≥ 5 rems TEDE" • Written Report within 30 days (LER)
Terminating Cue:	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

JPM Cue Sheet #1

- **A high dose maintenance activity is scheduled in the Fuel Building**
- **The general dose rate in the area is 100 mrem / hour but can be reduced to 25 mrem / hour if lead shielding is installed**
- **It will take NEOs A & B 30 minutes to install the shielding**
- **Independent of the shielding, it will take NEO A 2 hours or NEOs A & B 1.5 hours to perform the maintenance**

Initiating Cue: **The Work Control Supervisor directs you to PERFORM the following:**

- **CALCULATE the dose received when performing the maintenance for each of the following conditions:**

  - **NEO A without shielding** ___________ **mrem**
  - **NEOs A & B without shielding** ___________ **mrem**
  - **NEO A with shielding** ___________ **mrem**
  - **NEOs A & B with shielding** ___________ **mrem**

Initial Conditions: **Given the following conditions:**

JPM Cue Sheet #2

- **The Shift Manager was notified by Radiation Protection that an individual handling radioactive licensed material received 5.5 REM TEDE in a 3 hour period**

Initiating Cue: **The Shift Manager directs you to PERFORM the following:**

- **DETERMINE Oral and Written Reportability Requirements, if any**
  - **Oral Reporting Requirement** __________________
  - **Written Reporting Requirement** __________________

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS_________________/__________LATEST PCN/EFFECTIVE DATE ___1___ / 02/21/2017

LEVEL OF USE:
INFORMATION USE

QUALITY-RELATED

ALARA JOB PLANNING/DEBRIEFING

PROCEDURE NO. STA-657

REVISION NO. 19

SORC MEETING NO.: 15-015 **DATE:** 06/25/2015

EFFECTIVE DATE: 07/01/2015

PREPARED BY (Print): Shari Mosty EXT: 5204

TECHNICAL REVIEW BY (Print): Gerald W. Mandrell II EXT: 6711

APPROVED BY: *John Dreyfuss* DATE: 06/25/2015

PLANT MANAGER

1.0 PURPOSE

The purpose of this procedure is to provide guidance for the consideration, incorporation, and documentation of ALARA concepts and radiological work practices into the job planning and completion process in accordance with STA-651.

1.1 The forms listed below do not require SORC review when being modified and issued per STA-202:

- STA-657-1, RWP Request
- STA-657-2, ALARA Post-Job Debriefing
- STA-657-5, ALARA Attendance Record

2.0 APPLICABILITY

This procedure is applicable to work performed under a Radiation Work Permit. This procedure may also apply to work performed under a General Access Permit at the direction of the Radiation Protection Manager or designee. Exposure action levels in this procedure are based on Total Effective Dose Equivalent (TEDE).

3.0 REFERENCES

3.1 RPI-608, Control of Temporary Shielding

3.2 RPI-629, Radiological Risk Management

3.3 STA-123, Pre-Job and Post-Job Briefs

3.4 STA-302, Station Records

3.5 STA-606, Work Requests and Work Orders

3.6 STA-651, ALARA Program

3.7 STA-654, Personnel and Discrete Radioactive Particle Contamination Control

3.8 STA-656, Radiation Work Control

3.9 STA-659, Respiratory Protection Program

3.10 STA-660, Control of High Radiation Areas

3.11 STI-604.01, Integrated Risk Management

3.12 USNRC Regulatory Guide 8.8, Rev. 3, Information Relevant to Ensuring That Occupational Radiation Exposures at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable

3.13 Comanche Peak Technical Specifications

3.14 Significant Operating Experience Report 2001-1, Unplanned Radiation Exposures

3.15 IERL2 11-41, Unplanned Personnel Exposure from Highly Radioactive In-Core Components

3.16 Radiation Protection Best Practices, Identification and Controls for Work with Radiological Risk
[CR-2011-007501]

3.17 WCI-203, Weekly Surveillances / Work Scheduling

3.18 INPO Significant Operating Experience Report (SOER) 82-1, Radiation Overexposure of Maintenance Personnel

4.0 DEFINITIONS/ACRONYMS

4.1 Job Planning Meeting – A meeting (formal or informal) between Radiation Protection and the Responsible Work Organization to discuss the extent of job planning.

4.2 Post-job Debriefing – A special briefing to review job activities, procedural problems, or other occurrences which may affect personnel radiation exposure.

4.3 Pre-job Brief – An interactive preparatory meeting or discussion conducted before performing a task, designed to ensure the safe and efficient execution of the task. It consists of a review of the critical elements of the task, the role of team members in task accomplishment, hazards characteristic of the task and defenses employed to protect against the hazards, and a discussion of human performance tools to minimize errors, including error traps, assumptions, potential consequences of errors, and contingencies to mitigate consequences.

4.4 RWT – Radiation Worker Training

4.5 Responsible Work Organization (RWO) – The lead department that has responsibility for resolution of a work request and completion of the work order.

4.6 Work Supervisor – The individual responsible for coordinating the performance and completion of a defined task.

4.7 High Risk Activity (HRA) per WCI-203 – Any activity (e.g., test, surveillance or maintenance), that places the plant in a configuration that could significantly degrade the level of nuclear safety or presents a serious industrial safety hazard.

4.8 Radiological High Risk Activity – Radiological work where detailed planning and multiple diverse barriers are essential to prevent radiological events involving significant radiation levels, threats to regulatory radiation exposure limits, or may result in unanalyzed effluent release pathways to the environment or exposure to members of the public.

4.9 Radiological Medium Risk Activity – Radiological work where planned barriers are desirable to prevent inadequately controlled radiation levels, reduce threats for unplanned/unmonitored dose, minimize potential for level 2 or 3 personnel contamination events or potential contamination of non-radiological facilities or the environment within the protected area.

5.0 RESPONSIBILITIES

5.1 Responsible Work Organization is responsible for:

5.1.1 Providing an ALARA Representative.

5.1.2 Determining projected dose for jobs with assistance from Radiation Protection.

5.1.3 Coordinating and participating in Job Planning Meetings, Pre-Job Briefings, and Post Job Debriefings.

5.1.4 Evaluating and implementing recommendations and corrective actions that result from the Post-Job Debriefing process.

5.2 Work Supervisor is responsible for:
[CR-2011-012459]

5.2.1 Reviewing current radiation exposure reports for qualified personnel within the work group.

5.2.2 Assigning workers to equally distribute radiation dose among work group personnel when practical.

5.2.3 Participating in the Responsible Work Organization's ALARA job planning.

5.2.4 Providing oversight for Radiological High Risk Work.

5.2.5 Participating in Radiologically Significant pre-job briefs.

5.2.6 Participating in Radiological High Risk Work planning meetings.

5.2.7 Providing compensatory actions for Radiological High Risk Work.

5.3 Radiation Protection is responsible for:

5.3.1 Assisting the RWO in determining projected total effective dose equivalent for jobs.

5.3.2 Assisting the RWO in coordinating and participating in Job Planning Meetings, Pre-Job Briefings, and Post Job Debriefings.

5.3.3 Assisting the RWO in coordinating the implementation of recommendations and corrective actions.

5.4 ALARA Coordinator is responsible for:

5.4.1 Assisting Radiation Protection personnel in estimating the total effective dose equivalent for RWPs with exposure estimated to be equal to or greater than 1 person-rem.

5.4.2 Ensuring Radiation Protection participation in Job Planning, Pre-Job and Post-Job Debriefings.

5.4.3 Coordinating responses to ALARA suggestions.

5.5 ALARA Committee is responsible for:

5.5.1 Reviewing planning and debriefing for RWPs with TEDE greater than or equal to 5 person-rem.

5.6 Director, Nuclear Training is responsible for:

5.6.1 Providing RWT training to Radiation Workers.

5.7 Radiation Protection Manager is responsible for: **[CR-2011-012459]**

5.7.1 Maintaining this procedure current.

5.7.2 Reviewing and approving all Radiological High Risk Work.

5.7.3 Providing oversight for High Risk Radiological Work activities.

5.8 Radiation Protection Supervisor is responsible for: **[CR-2011-012459]**

5.8.1 Reviewing and approving Radiological Medium Risk Work RWP's Activities.

5.8.2 Providing oversight for Radiological Medium Risk Work activities.

5.9 Department ALARA Representative is responsible for:

5.9.1 Assisting in incorporating ALARA concepts into job performance activities.

5.9.2 Reviewing the ALARA Condition Reports and Site Critique Issues applicable to that representative's work organization.

6.0 INSTRUCTIONS

[C] 6.1 ALARA Job Planning
[27375][27376][27374]

The projected radiation exposure to complete a job primarily determines the degree of ALARA planning performed. Based on current survey data, accurate person-hour estimates, and any applicable historical data, the RWO and Radiation Protection should develop a dose estimate for the job.

6.1.1 All RWPs require documentation of job planning in accordance with RPI-606. ALARA initiates the STA-657-1 with input from the RWO during the generation of the RWP.

6.1.2 Planning should consist of RWP preparation and approval in accordance with STA-656 as well as the general radiation protection specifications and instructions for minimizing exposure (e.g., location of radiation sources and hot spots).

6.1.3 Radiological Medium Risk activities should be included in ALARA planning documents. For activities identified as medium risk, planning should include:

- A well-formulated estimate of the radiation levels when actual levels are unknown.
- Workers should document their understanding of the radiological risk with applicable pre-job briefings and work documents using STA-657-5.
- The pre-job briefings should include all aspects of work to be performed, clearly defined contingencies, and stop-work criteria.

[C] 6.1.4 Activities identified as High Risk in Attachment 2, page 3 shall incorporate the requirements in section 6.1.5 and 6.1.6 into applicable work authorizing documents such as work orders, procedures, radiation work permits, and ALARA packages.
[4307029][4307030][4765751][4765752]

6.1.5 Activities identified as High Risk in Attachment 2, page 2 should incorporate the following into applicable work authorizing documents such as work orders, procedures, radiation work permits, and ALARA packages:

- Direct involvement by the RP staff and the work supervisor in planning, preparing, and performing these high-risk work activities.
- Specific radiological protection instructions to prevent unplanned exposures. The instructions must include survey requirements, dose rate stop-work criteria, and cautions or radiological hold points prior to steps that could cause a significant increase in work area dose rates.

6.1.6 Ensure planning processes for high-risk activities require the following:

- A well-formulated estimate of the radiation levels when actual levels are unknown.
- Workers should document their understanding of the radiological risk with applicable pre-job briefings and work documents using STA-657-5.
- The pre-job briefings should include all aspects of work to be performed, clearly defined contingencies, and stop-work criteria.
- Pre-job briefings to be attended by all workers and RP technicians involved, as well as line and RP supervision
- Reliable communications between workers and RP technicians who monitor radiological conditions.
- Perform a challenge review board with the ALARA Committee to review the radiological controls for the high-risk work prior to the approval of the RWP.
- Approval of the work plan by the work group and Radiation Protection manager (or designees), as a minimum.

[C] 6.1.7 In-service inspection of steam generator tubing shall include the following:

- Pre-job planning should be undertaken to make provisions for steam generator tube inspections that ensure that personnel radiation exposure is maintained ALARA.
  [08326]

6.1.8 A Job Planning Meeting should be held with Radiation Protection, the Responsible Work Organization, and any other work groups as necessary.

6.1.9 The Job Planning Meeting should address problems and concerns associated with job performance. Action items should be identified, responsibilities assigned, and STA-657-1 completed.

NOTE: A Job Planning Meeting can be performed face-to-face, electronic or via phone. Meeting should be in sufficient detail to address all radiological concerns associated with the work activity and mitigate to extent possible.

6.1.10 Prior to the Job Planning Meeting, Radiation Protection should consider the following:

- Related Work History (e.g., RWP files, surveys, etc.).
- Applicable sketches, photos, and other related documentation of work area and equipment.
- Applicable procedures written for the task to determine the need for radiological hold points and to identify any other radiological concerns.
- Methods to mitigate radiological risks
- Radiation Protection Technician performing job coverage involved in work planning and pre-job briefings.
- Operating Experiences.

6.1.11 Prior to the Job Planning Meeting, the RWO should consider the following:

- Related Work History (e.g., Recurring problems, etc.).
- Applicable sketches, photos, and other related documentation of work area and equipment
- Applicable procedures
- Person hours (total vs. actual time on component)
- Other stakeholders

6.1.12 Mock-ups may be utilized in establishing person-rem estimates. In addition, they are useful in identifying potential problems with the work procedures. The following are other factors that should be considered during the Job Planning Meeting:

- Training
- Work Experience

6.1.13 The following Engineering Controls (and a comparison of dose saved) should be considered during the Job Planning Meeting:

- Use of portable and remote ventilation equipment
- Contamination enclosures and glove boxes
- Shielding (RPI-608)
- Draining, flushing, or filling a source pipe

6.1.13 Continued

- Removal of equipment to lower exposure areas
- Removal of sources of radiation
- Decontamination
- Perform work under water

[C] 6.1.14 Special Tools and remote handling devices to reduce time and increase distance from the source shall be utilized when practical.
[10885]

6.1.15 Other factors to consider at the Job Planning Meeting include the following:

- Rescheduling of the job to take advantage of reduction of dose rates and contamination from decay after shutdown.

- Alternatives to respiratory protection such as decontamination, glove boxes, and wet work should be used when appropriate. If respirators must be used, selection should be based on requirements specified in STA-659.

- Manpower requirements should be considered with respect to the most efficient number of workers, use of tool handlers and helpers in adjacent lower dose rate areas, and accumulated exposure of each individual worker.

- Potential problems such as radioactive material spills and equipment failures should be considered and response actions planned.

- Other job-specific considerations should include items such as additional lighting, communication equipment and remote video surveillance.

- Alternate work methods should be analyzed based on mock-up training and historical data.

6.2 <u>ALARA Committee Review</u>

6.2.1 RWPs with projected collective total effective dose equivalent of 5 person-rem or greater should have an additional review by the ALARA Committee. Exposure estimate revisions to such RWPs that would result in a cumulative exposure increase of greater than or equal to 25% require a supplemental ALARA Committee review.

6.2.2 The Responsible Work Organization should present the RWP planning package to the ALARA Committee for review.

6.2.3 The ALARA Committee Meeting number should be documented on the job-planning form(s).

6.2.4 The RP Supervisor or ALARA Coordinator should schedule a meeting for the ALARA Committee to review the ALARA Job Planning forms. This review should be documented in the ALARA Committee Meeting Minutes.

6.3 ALARA Post-Job Debriefing

[C] 6.3.1 An ALARA Post-Job debriefing shall be conducted for an RWP when unplanned events develop which affect total effective dose equivalent.
[06603]

6.3.2 An ALARA Post-Job Debriefing should be conducted for an RWP when any of the following conditions apply:

6.3.2.1 The Power Operations RWP collective total effective dose equivalent is greater than or equal to 0.100 person-rem and varies by 25% from the pre-job estimate that is not clearly identified (e.g., scope change, known change in radiological conditions, etc.).

6.3.2.2 The Outage RWP collective total effective dose equivalent varies by 25% from the pre-job estimate that is not clearly identified (e.g., scope change, known change in radiological conditions, etc.).

6.3.2.3 Whenever requested by an employee involved in the task/RWP or RP Supervisor.

NOTE: A post-job review letter may be used in lieu of a post-job debriefing for RWPs with actual collective total effective dose equivalent less than 1 person-rem if any deviations from the estimate are clearly identified, RP Supervision or ALARA coordinator approval is obtained, and no significant information is expected from a post-job debriefing. See Attachment 1 for an example Post-Job Review Letter.

6.3.3 When an ALARA Post-Job Debriefing is required, Radiation Protection should notify the Responsible Work Organization.

6.3.3.1 The ALARA Post-Job Debriefing should be scheduled with Radiation Protection and the Responsible Work Organization and integrated into the work group's post-work review process when possible.

[C] 6.3.3.2 The ALARA Post-Job Debriefing Checklist, STA-657-2, shall be completed during the meeting. Observed problems and recommended solutions should be documented on the form or attached pages.
[07368][06603]

6.3.3.3 When a Post-Job Debriefing is required, the minimum attendance should include workers directly involved with the job. In addition, the Radiation Protection job coverage technician and the Responsible Work Organization's Work Supervisor can be debriefed as a group or individually.

6.3.3.4 When the total effective dose equivalent of any RWP equals or exceeds 5 person-rem the ALARA Committee should review the Post-Job Debriefing results or the ALARA Outage Report.

6.3.3.5 All ALARA Post-Job Debriefings should include a discussion of the following:
[CR-2005-005028]

- ***C***<u>hanges</u> – Does the procedure or work instructions governing the task/job need to be changed prior to next performance?
- ***L***<u>essons Learned</u> – Are there lessons learned or improvement opportunities from this task/job that should be recorded and passed along to others?
- ***E***<u>rrors Left Uncorrected</u> – Did conditions exist that if left uncorrected could lead to a human error the next time the task is performed?
- ***A***<u>dequate Resources</u> – Were resources, such as schedules, tools, materials, people, training and support organizations, adequate to support task achievement?
- ***R***<u>esults not expected</u> – Was the task or job completed with unexpected results?

6.3.3.6 The Post-Job Debriefing should provide a summary of the RWP's performance. In the ALARA RWP Analysis section of the STA-657-2, provide applicable information for the following:

- An exposure performance evaluation of actual exposure against expected exposure.

- An assessment of actual work hours as well as those used in the evaluation of the ALARA Job Planning dose estimate.

- Where a detailed task breakdown existed as part of the ALARA Job Planning for the work, the exposure performance evaluation should be conducted at the task level whenever possible for RWP's greater than 1 Rem.

- Assessment of Personnel Contamination Events to determine if RWP controls were adequate.

6.3.3.6 Continued

- Identification of the strengths and weaknesses encountered during the planning and performance of the work.

- Identification of improvements that should be incorporated into future work.

- Evaluation of the effectiveness of the ALARA Job Planning.

6.4 Lessons Learned

6.4.1 Lessons learned contain facts that can be used during subsequent work or planning activities in order to avoid exposure or to enhance the work process.

6.4.2 Lessons learned are captured from in-process reviews and post-job debriefs, ALARA concerns and suggestions, and Site Critique Issues in accordance with STA-651.

6.4.3 When capturing lessons learned, the following factors should be considered:

- Issues involving safety
- Recurring issues
- Issues that contribute directly to exposure
- Issues involving work area set-up
- Issues involving tooling and equipment reliability
- Scheduling Conflicts

6.4.4 Lessons learned (e.g., Condition Reports, etc.) should be documented in the respective RWP folder.

7.0 FIGURES

None

8.0 ATTACHMENTS/FORMS

8.1 Attachments

8.1.1 Attachment 1, Post-Job Review Letter (Example)

8.1.2 Attachment 2, Radiological Medium/High Risk Activities

8.2 Forms

8.2.1 STA-657-1, RWP Request

8.2.2 STA-657-2, ALARA Post-Job Debriefing

8.2.3 STA-657-5, ALARA Attendance Record

9.0 RECORDS

When completed, the following forms, reports, or other documents generated in response to this procedure shall be dispositioned in accordance with STA-302.

9.1 STA-657-1, RWP Request

9.2 STA-657-2, ALARA Post-Job Debriefing

9.3 STA-657-5, ALARA Attendance Record

ATTACHMENT 1
PAGE 1 OF 1

POST-JOB REVIEW LETTER (EXAMPLE)

POST-JOB REVIEW LETTER FOR RWP -
RWP TITLE:

Estimated Exposure Person-Rem
Actual Exposure Person-Rem

NOTE: This form can be used when actual collective total effective dose equivalent is < 1 person-Rem and deviations from the estimate are clearly identified (i.e., change in radiological conditions, work scope changes, etc.) and authorized by ALARA supervision.

Comments:

ALARA Technician: ______________________________ Date: __________________

ALARA Supervisor: ______________________________ Date: __________________

ATTACHMENT 2
PAGE 1 OF 3

RADIOLOGICAL MEDIUM/HIGH RISK ACTIVITIES

NOTE: The Radiological Medium/High Risk activities may also be found in RPI-629.

Medium Risk Activities
[CR-2011-007501]

- Worker exposed to 100 mrem per hour and expected dose to individual is > 200 mrem.
- Potential for airborne exposure greater than 2 DAC or for an individual to receive

  4 DAC-hours in a single entry.
- Work in contamination areas where the general area is greater than

  200,000 dpm/100 cm^2.
- Work activities involving abrasive or aggressive mechanical action such, as grinding, machining or flapping and welding on contaminated material with transferable beta gamma contamination levels greater than 50,000 dpm/100 cm^2 OR any potential fixed alpha contamination.
- Work performed in a Category 3 or Category 4 discrete radioactive particle control zone.
  - Category 3 - > 25mrad/hr to < 50 mrad/hr
  - Category 4 - > 10,000 ncpm to < 25 mrad/hr
- Work in non-uniform radiation fields where multiple dosimetry is used OR where the worker's primary dosimeter is moved to a location other than the front of the torso OR any use of effective dose equivalent-external (EDEex) OR any use of extremity dosimetry.
- Radiological work outdoors or in buildings not designed for radiological work
- Entry into alpha level II areas.
- Activities subject to changing and elevated radiological conditions.
- Any work determined by Radiation Protection Supervision or Management.

ATTACHMENT 2
PAGE 2 OF 3

RADIOLOGICAL MEDIUM/HIGH RISK ACTIVITIES

High Risk Activities
[CR-2011-007501]

- Under water diving operations in spent fuel pool or reactor cavity.
- Worker exposed to 1500 mRem/hr OR expected dose to be received is ≥ 500 mRem.
- Jobs with the potential for airborne radioactivity in excess of 10 DAC or an individual could receive 40 DAC-hours in a single entry. 1
- Entry into loop rooms at Mode 1 past labyrinth
- Potential for shallow dose equivalent rate to skin in excess of 10 rads per hour or individual directly handling items with contact dose equivalent rate (beta plus gamma) exceeding 10 rads per hour.
- Work area contamination > 1 Rad per hour on a smear.
- Work performed in a Category 1 or Category 2 discrete radioactive particle control zone.
  - Category 1 - > 100 mrad/hr
  - Category 2 - > 50 mrad/hr to < 100 mrad/hr
- Radiography
- Entry into alpha level III areas.
- Source Transfer or handling of sources > 1 Rem/hr
- Incore thimbles removal and cutting
- Maintenance and removal of irradiated flux detectors
- Activities under vessel
- Any work determined by Radiation Protection Supervision or Management.

IER L2-11-41 identified High Risk Activities – See Page 3

ATTACHMENT 2
PAGE 3 OF 3

RADIOLOGICAL MEDIUM/HIGH RISK ACTIVITIES

IER L2-11-41 identified High Risk Activities:

[C] Activities to consider when evaluating the applicability of IER L2-11-41 include the following: **[4307028]**

- Replacement or repair of in-core detectors, or repair of in-core drive units that could result in the inadvertent movement of the detectors.
- Activities associated with the disassembling or reassembling of the seal table that could result in a worker moving or retracting a thimble prior to establishing controls in undervessel areas.
- Retracting in-core thimbles.
- Removing irradiated hardware from the water/shielding in the reactor vessel, cavity or spent fuel pool (this does not apply to moving fuel unless the fuel is damaged).
- Accessing areas under the vessel or seal table room during periods when incore detectors could be operated.
- Handling equipment or tools after they are used to cut or repair irradiated hardware or components (for example, a crusher-shearer).

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS____________/_____________ LATEST PCN/EFFECTIVE DATE ___________

LEVEL OF USE:
INFORMATION USE

QUALITY-RELATED

NONROUTINE REPORTING

PROCEDURE NO. STA-501

REVISION NO. 21

SORC MEETING NO. 16-07 DATE: 04/20/16

EFFECTIVE DATE: 04/28/16

PREPARED BY (Print): Gary Merka EXT: 6613

TECHNICAL REVIEW BY (Print): Jim Barnette EXT: 5866

APPROVED BY: John Dreyfuss DATE: 4/20/16
PLANT MANAGER

1.0 PURPOSE

The purpose of this procedure is to identify the nonroutine reporting requirements applicable to CPNPP, and to identify the process and responsibilities for nonroutine report preparation, review, and approval.

2.0 APPLICABILITY

This procedure is applicable to those groups with responsibilities related to the nonroutine reporting requirements imposed on CPNPP by the Nuclear Regulatory Commission (NRC), other Federal regulatory agencies, and the State of Texas.

3.0 REFERENCES

3.1 Facility Operating License (OL) No. NPF-87 for CPNPP Unit 1 and OL No. NPF-89 for CPNPP Unit 2

3.2 CPNPP Final Safety Analysis Report (FSAR)

3.3 CPNPP Emergency Response Plan (EP)

3.4 CPNPP Environmental Protection Plan (EPP)

3.5 CPNPP Technical Requirements Manual (TRM)

3.6 CPNPP Technical Specifications (T/S)

3.7 CPNPP Offsite Dose Calculation Manual (ODCM)

3.8 Code of Federal Regulation (CFR), Title 10, Energy

3.9 Code of Federal Regulation (CFR), Title 40, Protection of Environment

3.10 Code of Federal Regulation (CFR), Title 49, Transportation

3.11 NUREG-0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, Revision 1 (11/80)

3.12 NUREG-0775, Final Environment Statement Related to the Operation of CPSES Units 1 and 2 (9/81)

3.13 NUREG-0797, Safety Evaluation Report (SER) including supplements Related to the Operation of Comanche Peak Steam Electric Station

3.14 NUREG-1022, Revision 3, Event Report Guidelines 10 CFR 50.72 and 50.73 (01/13)

3.15 NUREG-1216, Safety Evaluation Report Related to the Operability and Reliability of Emergency Diesel Generators Manufactured by Transamerica Delaval, Inc. (8/86)

3.16 NUREG-1304, Reporting of Safeguards Events (2/88)

3.17 NUREG-1385, Fitness for Duty in the Nuclear Power Industry: Responses to Implementation Questions (10/89)

3.18 Texas Administrative Code Rule 289.257, Packaging and Transportation of Radioactive Material

3.19 RG-1.108, Periodic Testing of Diesel Generators Used as Onsite Electric Power Systems at Nuclear Power Plants, Rev. 1 (8/77)

3.20 RG-1.133, Loose-Part Detection Program for Primary System of Light-Water Cooled Reactors (9/77)

3.21 Generic Letter (GL) 91-02, Reporting Mishaps Involving LLW Forms Prepared for Disposal (12/90)

3.22 Procedure EPP-121, Re-entry, Recovery and Closeout

3.23 Procedure EPP-203, Notifications

3.24 Procedure STA-104, Duty Manager

3.25 Procedure STA-401, Station Operations Review Committee

3.26 Procedure STA-421, Initiation of Condition Reports

3.27 Procedure STA-422, Processing Condition Reports

3.28 Procedure STA-502, Routine Reporting

3.29 Procedure STA-709, Radioactive Waste Management Program

3.30 Procedure STA-910, Fitness for Duty Program

3.31 TCEQ-TPDES Wastewater Discharge Permit No. 01854

3.32 Quick Reference Guide for Environmental Matters, Luminant Power Environmental Services

3.33 Federal Register, Volume 56, Number 147, July 31, 1991, Criteria and Procedures for the Reporting of Defects and Conditions of Construction Permits

3.34 Licensing Guideline 12-01, Reportability Evaluations

3.35 CPNPP Security Plan

3.36 Procedure STA-913, Cyber Security Program

3.37 Holtec International 10 CFR Part 72 Certificate of Compliance 1014 for the HI-STORM 100 System, Amendment 7.

3.38 Procedure STA-125, Luminant Corporate Compliance Procedure Control

3.39 NEI 13-01, Reportable Action Levels for Loss of Emergency Preparedness Capabilities

3.40 RG 5.83, Cyber Security Event Notifications (7/15)

3.41 NEI 15-09, Cyber Security Event Notifications

4.0 DEFINITIONS/ACRONYMS

4.1 Adversary - Individual, group or organization that has adversely impacted or is attempting to adversely impact a CDA.

4.2 Adverse impact - A direct deleterious effect on a Critical Digital Asset (CDA) (e.g., loss or impairment of function, reduction in reliability, reduction in the ability to detect, delay, assess or respond to malevolent activities, reduction of ability to call for or communicate with offsite assistance, and the reduction in emergency response ability to implement appropriate protective measures in the event of a radiological emergency). In the case where the direct or indirect compromise of a support system causes a safety-related, important-to-safety, security or emergency preparedness system or support system to actuate or “fail safe” and not result in radiological sabotage (i.e., causes the system to actuate properly in response to established parameters and thresholds) this is not considered to be an adverse impact in the context of 10 CFR 73.54(a).

4.3 Alert And Notification System (ANS) - The system that demonstrates compliance with the public alerting and notification planning standard described in 10CFR50.47(b)(5) and the associated requirements of section IV.D of 10CFR50, Appendix E.

4.4 Alternate Facility - A temporary location that may serve as a Technical Support Center (TSC) or Emergency Operations Facility (EOF) in support of a planned work activity. An acceptable Alternate Facility must have sufficient capability to support effective direction and control of an emergency response; however, it need not meet the same design or operating requirements applied to a normally used ERF (e.g., it may not possess a protected ventilation system).

4.5 Backup Emergency Response Facility (ERF) - A facility that may serve as the TSC or EOF in the event that the primary facility is unavailable, as described in the emergency plan or a procedure described in the emergency plan. An acceptable Backup ERF must meet the requirements of 10CFR 50, Appendix E, sections IV.E.8.a and 8.c, and be functionally equivalent to the primary facility.

4.6 By-Product Materials - Any radioactive material (except special nuclear material) yielded in or made radioactive by exposure to the radiation incident to the process of producing or utilizing special nuclear material.

4.7 Compensatory Measure - A temporary means, established as part of a planned activity, to perform a given emergency response function during a period when the normally used methods are unavailable such that, when implemented, there is a reasonable expectation that the function would be accomplished during an actual emergency, albeit in a possibly degraded manner. A Compensatory Measure need not meet the same design or operating requirements as the normally used methods but must be sufficient to support effective implementation of the site emergency plan. Also refer to the related term “Viable”.

4.8 Compromise - Disclosure of information to unauthorized persons, or a violation of the security policy of a system in which unauthorized intentional or unintentional disclosure, modification, destruction, or loss of an object may have occurred.

4.9 Contraband - Includes any dangerous weapon, explosive, or other dangerous instrument or material likely to produce substantial injury or damage to persons or property. (Safety flares carried on vehicles as emergency road equipment need not be considered incendiary devices for the purposes of reportability).

4.10 Credible - Information received from a source determined to be reliable (e.g., law enforcement, government agency, etc.) or has been verified to be true. A threat can be verified to be true or considered credible when: Physical evidence supporting the threat exists; Information independent from the actual threat message exists that support the threat; OR a specific known group or organization claims responsibility for the threat.

4.11 Credible Threat - A threat where: (1) physical evidence supporting the threat exists, (2) information independent from the actual threat messages exists that supports the threat, or (3) a specific group or organization claims responsibility for the threat.

4.12 Critical Digital Asset (CDA) - A digital computer, communication system, or network that has been identified through site-specific analysis required in 10 CFR 73.54(b)(1) as requiring protection against a cyber attack. A CDA may be:

- a component of a critical system (this includes assets that perform safety, security, or emergency preparedness functions; provide support to, protect, or provide a pathway to Critical Systems); OR
- a support system asset whose failure or compromise as the result of a cyber attack would result in an adverse impact to a safety, security, or emergency preparedness function.

4.13 Critical system (CS) - A system that is associated with or provides safety-related functions; important-to-safety functions; security functions; emergency preparedness function, including offsite communications; or support systems and equipment which, if compromised, would adversely impact safety, security, or emergency preparedness functions.

4.14 Cyber Attack - Any event in which there is reason to believe that an adversary has committed or caused, or attempted to commit or cause, or has made a credible threat to commit or cause malicious exploitation of a CDA.

4.15 Emergency Action Level (EAL) - A pre-determined, site-specific, observable threshold for an Initiating Condition that, when met or exceeded, places the plant in a given emergency classification level, as described in the emergency plan or an implementing procedure described in the emergency plan.

4.16 Emergency Assessment - The evaluation of plant information such as operational and radiological indications and data, and reports from onsite and offsite sources, to determine the consequences of an accident or other emergency-related event, and the appropriate measures for mitigation and protection of the public. Radiological Assessment is a sub-function of Emergency Assessment.

4.17 Emergency Notification System (ENS) - A telephonic communications system designed to allow a licensee to provide timely notifications to the NRC Operations Center of off-normal incidents affecting a facility, and information concerning the operation and status of the plant.

4.18 Emergency Response Data System (ERDS) - The direct near real-time electronic data link between a licensee's onsite computer system and the NRC Operations Center that provides for the automated transmission of a limited data set of selected parameters as required by section VI of 10CFR50, Appendix E.

4.19 Emergency Response Facility (ERF) - A licensee facility that demonstrates compliance with planning standard 10CFR50.47(b)(8) and is staffed by members of the licensee's Emergency Response Organization during an emergency.

4.20 Emergency Response Organization (ERO) - The organization of qualified licensee personnel that demonstrates compliance with planning standard 10CFR50.47(b)(2).

4.21 Event Discovery Date - The date or time which starts the clock for reports due to regulatory agencies. Typically, it is the date that a CPNPP worker identifies a problem or an issue. However, if the problem requires an engineering evaluation to determine operability or significance of the problem, the Event Discovery Date is the date the engineering evaluation is completed.

4.22 Federal Emergency Management Agency (FEMA) - The federal government agency with responsibility for reviewing and assessing offsite emergency plans and preparedness for adequacy, and making findings and determinations as to whether offsite emergency plans are adequate and can be implemented.

4.23 Health Physics Network (HPN) - A telephonic communications system designed to allow a licensee to provide health physics (radiological) and environmental monitoring information to the NRC Operations Center during an emergency.

4.24 Immediate Notification - Verbal communication with the NRC or other outside agencies as required by regulations, and/or the operating license.

4.25 Initiating Condition (IC) - An event or condition that aligns with the definition of one of the four emergency classification levels by virtue of the potential or actual effects or consequences, as described in the emergency plan or an implementing procedure described in the emergency plan. An IC provides one or more EALs which, when met, will require an emergency declaration.

4.26 Integrity - Quality of a system reflecting the logical correctness and reliability of the operation of the system; the logical completeness of the hardware and software implementing the protection mechanisms; and the consistency of the data structures and occurrence of the stored data. Additionally, integrity includes protection against unauthorized modification or destruction of information.

4.27 Interim Compensatory Measures (ICM) Event - An event that is driven by violation, incursion or deviation from current ICM, special Regulatory Information Summary (RIS) or other regulatory requirement(s) associated with elevated security levels as identified by the NRC or Office of Homeland Security. This includes the necessity to implement required actions noted for a given event.

4.28 Independent Spent Fuel Storage Installation (ISFSI) - A complex designed and constructed for the interim storage of spent nuclear fuel, solid reactor-related GTCC (Greater than Class C) waste, and other radioactive materials associated with spent fuel and reactor-related GTCC waste storage. An ISFSI which is located on the site of another facility licensed under 10CFR50 and which shares common utilities and services with that facility or is physically connected with that other facility should still be considered independent. Comanche Peak operates its ISFSI under the general license provisions of 10CFR72, Subpart K.

4.29 Licensed Material - Those source materials, special nuclear materials, or by product materials received, possessed, used, or transferred under a general or specific license issued by the NRC.

4.30 Method - A means that could be employed to perform an emergency response function as described in the emergency plan or an implementing procedure described in the emergency plan. Site emergency plans and implementing procedures typically describe primary and one or more alternate Methods for performing a given function. Provided that at least one Method is available, then the ability to perform the associated function has not been lost.

4.31 Non-Emergency Event - Any of those conditions specified in 10CFR50.72(b).

4.32 Nonroutine Report - A required report to the NRC, or other regulatory agency, that is prompted by an unplanned/unexpected/unusual event, situation, or condition at CPNPP or related to CPNPP.

4.33 Offsite Response Organization (ORO) - Those state, local and tribal agencies with primary responsibility for coordinating and implementing offsite emergency measures.

4.34 Plant Incident - A significant variation from normal plant operations or equipment performance that is of interest to plant management, including those events requiring a report to a regulatory agency.

4.35 Prompt Notification - Notification of a regulatory agency within the specific time requirements of a particular regulation, technical specification, or license condition. Typically within 24 hours.

4.36 Radiological Assessment - An evaluation of plant parameters and radiological data performed to determine potential or actual offsite doses during an emergency. This function is sometimes referred to as "dose assessment" and supports the performance of Emergency Assessment.

4.37 Reactor Coolant System (RCS) - The system used to remove energy from the reactor core.

4.38 Reportable Action Level (RAL) - A predetermined, site-specific, observable threshold that, when met or exceeded, requires notification of the associated event to the NRC in accordance with 10CFR50.72(b)(3)(xiii).

4.39 Reportable Event - Any operation, event or condition requiring submittal of a nonroutine report.

4.40 Restoration Time - The time available for restoring a lost structure or piece of equipment to service. Where allowed, Restoration Times are specified in the RALs.

4.41 Routine Report - A required report to the NRC or other regulatory agency which is required on a periodic basis (e.g., monthly, annually, per fuel cycle, etc.); which is prompted by planned or normally expected events or situations (e.g., changes to an emergency plan, nuclear material transactions, waste shipments, etc.); or which is prompted by a request (e.g., personnel exposure request, operators' medical history request from the NRC, etc.); or information from periodic reviews which will be maintained in a file to support a future inspection.

The routine reports are further identified by numbering with the following prefix codes:

Routine Periodic (RP) - a routine report which is required on a periodic basis.

Routine Non-periodic (RN) - a routine report which is prompted by expected events or upon request by an agency.

Routine Record (RR) - information from periodic reviews that are retained as records for future inspections.

4.42 Safeguards Event - Any incident representing and attempted, threatened, or actual breach of the safeguards system or reduction of the operational effectiveness of that system.

4.43 Source Materials - (i) Uranium or thorium, or any combination thereof, in any physical or chemical form; or (ii) ores which contain by weight one-twentieth of one percent (0.05%) or more of (a) uranium, (b) thorium or (c) any combination thereof. Source material does not include special nuclear material.

4.44 Special Nuclear Material (SNM) -(i) Plutonium, uranium 233, uranium enriched with the isotope 233 or in the isotope 235, and any other material which the Commission, pursuant to the provisions of section 51 of the act, determines to be special nuclear material, but does not include source material; or (ii) any material artificially enriched by any of the foregoing but does not include source material.

4.45 Special Report - A nonroutine written report to the NRC required by a particular Technical Specification or Technical Requirement Manual or Offsite Dose Calculation Manual requirement and made pursuant to 10CFR50.36(c)(2).

4.46 TCEQ – Texas Commission On Environmental Quality

4.47 TPDES – Texas Pollution Discharge Elimination System

4.48 Viable - A Compensatory Measure that (1) can restore a required function in a reasonably comparable manner and (2) is proceduralized prior to an event. Proceduralized means that the necessary instructions to perform a function exist in a document (e.g., a procedure, a user aid, a night or standing order, etc.) that will be followed by response personnel should an emergency occur. Further, individuals expected to implement the Compensatory Measure must be aware of the measure, in advance of its potential or actual implementation. A Viable Compensatory Measure does not include reliance upon “skill-of-the-craft” or individual judgment.

5.0 RESPONSIBILITIES

5.1 The Senior Vice President & Chief Nuclear Officer, is responsible for the overall control and management of activities necessary to satisfy the nonroutine reporting requirements imposed on CPNPP by federal and state agencies.

5.2 The Site Vice President, Vice President of Nuclear Engineering and Support, Manager, Regulatory Affairs and Director, Organizational Effectiveness are responsible for ensuring that resources are available and responsibilities are assigned for activities related to the identification and evaluation of potentially reportable events and conditions; the notifications required by various federal and state agencies; and the preparation, approval, and submittal of required written reports, as applicable, as assigned in Attachment 8.D.

5.3 The Shift Manager is responsible for:

5.3.1 Making initial reportability determinations and, when required, notifying the proper outside agencies within the specified time limit; and

5.3.2 Advising plant management of existing plant conditions for potential reportability considerations.

5.3.3 Promptly advising the Duty Manager when a 24-hour notification is required.

5.4 The Duty Manager's responsibilities are detailed in STA-104. The Duty Manager normally shall perform the activities of the Plant Manager on back shift and weekends. The Duty Manager is responsible for ensuring that required notifications are made within the specified time limit and to make those 24-hour notifications assigned to plant management.

5.5 The Manager, Regulatory Affairs is responsible for:

5.5.1 Maintaining cognizance of the nonroutine reporting requirements of each federal and state agency with jurisdiction over CPNPP.

5.5.2 Assisting plant management in the determination and resolution of potential reportable incidents, and

5.5.2 Maintaining a log of assigned Licensee Event Report and Special Report numbers, and

5.5.3 Maintaining this procedure current.

5.6 The Manager, Environmental is responsible for preparation, review, approval and submittal of nonroutine reports assigned to Environmental Services in Attachment 8.D.

5.7 Responsible Managers delineated in Attachment 8.D are responsible for ensuring their respective organizations execute reporting duties and actions as defined in this procedure within the specific time limits.

5.8 The responsibilities of the Station Operations Review Committee are defined in STA-401 and Attachment 8.D.

5.9 The responsibilities of the Operations Review Committee are defined in the ORC Manual and Attachment 8.D.

6.0 <u>INSTRUCTIONS</u>

6.1 <u>Event Identification and Documentation</u>

6.1.1 Personnel discovering a potentially reportable event or condition should ensure that the following actions are taken:

- the Shift Manager is immediately notified of the details of the event or condition,
- the individual's direct supervisor is notified, and
- a Condition Report is initiated in accordance with STA-421.

6.1.2 The Shift Manager should make the initial determination of reportability in accordance with STA-422 and ensure that the following actions are initiated for any event determined to be reportable:

- if the event or condition involves a security system or cyber security element, notify the Security Shift Supervisor
- notify plant management in accordance with Operations department policy,
- make the required notifications to offsite agencies in accordance with Section 6.2 and the Emergency Plan.

6.2 <u>Notifications</u>

6.2.1 Responsibility for notifications is defined in Attachment 8.D.

6.2.2 Notification of the NRC Operations Center shall be made using the Emergency Notification System (ENS). Events and conditions requiring notification of the NRC Operations Center are listed in Attachments 8.B and 8.D If the ENS is unavailable, then notification should be made using commercial telephone service (or any available alternate method) at the following numbers:

Primary	(301) 816-5100
Backup	(301) 951-0550
Second Backup	(301) 415-0550
Emergency Response Data System (ERDS)	(301) 816-5160
Facsimiles	(301) 816-5151

6.2.3 Notification of the NRC Region IV Administrator should be made using commercial telephone service at the following number: 1-817-860-8100.

6.2.4 If telegram, facsimile, e-mail or mailgram confirmation of the notification is required, the notification should be addressed to the notified agency, and contain the details of the notification.

6.2.5 Notification made following declaration of an emergency classification shall be made in accordance with the requirements of the CPNPP Emergency Plan.

6.2.6 Notification to the Federal Aviation Administration (FAA) and/or the Federal Bureau of Investigation (FBI) may be necessary for events associated with air vehicles (e.g., aircraft, parachutes, balloons) as they are associated with potential violations or deviation from current ICM, special RIS or other regulatory requirements(s) associated with elevated security levels. In addition to telephone notifications as indicated in 6.2.2 and 6.2.3, the following telephone numbers are available for making notifications for events and conditions requiring notification of the FAA/FBI listed in Attachments 8.B and 8.D:

FAA (24 hours)	(817) 858-7503
FAA Backup	(817) 541-3423
FBI (Days M-F)	(254) 772-1627
FBI Backup	(210) 225-6741
Somervell County Sheriff	(254) 897-2242

6.3 Preparation, Review and Approval of Non-Routine Reports

6.3.1 The responsibility for report preparation is assigned in Attachment 8.D. The Manager assigned responsibility for nonroutine report preparation (responsible manager) should ensure that the report is prepared in accordance with applicable procedural and regulatory requirements.

6.3.2 Attachment 8.B provides a listing of the source requirements for nonroutine reporting. The applicable sources should be reviewed to ensure the summary of the specific requirements as described in Attachment 8.D are current.

6.3.3 Preparation should include sufficient review to ensure accuracy and thoroughness of information.

6.3.4 Reports required to be submitted to the NRC should be transmitted to the Manager, Regulatory Affairs by the responsible manager, allowing sufficient time for processing.

6.3.5 The SORC shall review all events submitted pursuant to 10CFR50.73 or as a result of an accidental, unplanned or uncontrolled radioactive release. Other nonroutine reports may be reviewed at the discretion of the SORC Chairman or responsible manager.

7.0 FIGURES

None

8.0 ATTACHMENTS/FORMS

8.1 Attachments

8.A Telephone Notification Guidelines

8.B Summary of Nonroutine Reports

8.C Keyword Listing

8.D Nonroutine Report Descriptions

8.2 Forms

None

9.0 RECORDS

None

ATTACHMENT 8.A
PAGE 1 OF 3

TELEPHONE NOTIFICATION GUIDELINES

I. 10CFR50 Notifications

The following information should be included as applicable with a 10CFR50 notification:

1. Reporting requirement
2. CPNPP Unit No.
3. Event description
4. Date and time of the event (including CST/CDT)
5. Location (Room number)/Elevation
6. Personnel involved (utility/contractor)
7. Reactor power/mode (in percent at the time of the event)
8. Reactor power/mode (in percent at the time of the report)
9. Anything unusual or not understood (including secondary side)
10. Status of safety systems/function as required
11. ESF actuation (including Diesel Generators)
12. LCO statement
13. SI or ECCS (initiating signal)
14. Resident inspector informed (or will be)

TELEPHONE NOTIFICATION GUIDELINES

15. Cause of the event (call back if not known)

    - mechanical
    - electrical
    - personnel error
    - procedural inadequacy
    - other

16. Sequence of actions or system interactions

17. Plans for reactor operations/mode until corrected/restart

18. For fitness for Duty Events

    - amount and type of illegal drug or alcohol involved
    - activities of the person(s) involved
    - duration on duty

19. Other external notifications

TELEPHONE NOTIFICATION GUIDELINES

II. Part 72 Notifications

The following information shall be identified in making an initial Part 72 telephone report under 10CFR72.75(a), (b), (c) or (d):

1. The emergency class declared; or

2. For non-emergency events, the applicable paragraph, (b), (c), or (d), of 10 CFR 72.75 that applies to the event.

3. The caller's name and call-back telephone number.

4. A description of the event, including date and time.

5. The exact location of the event.

6. The quantities and chemical and physical forms of the spent fuel, high-level waste (HLW), or reactor-related greater-than-class-C (GTCC) waste involved in the event.

7. Any personnel radiation exposure data.

Telephone notifications should use the appropriate NRC form which should then be scanned and electronically attached to the respective Condition Report. FFD events are an exception, they use the appropriate NRC form but are not documented on a Condition Report. NRC forms (e.g. NRC forms 361 and 366) are available from the NRC's website (www.nrc.gov).

ATTACHMENT 8.B

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Excessive radioactive contamination or levels on package of radioactive material received ● removable > limits of 10CFR71.87 (i) ● external > limits of 10CFR 71.47	10CFR20.1906 (d) (1) 10CFR20.1906 (d) (2)	Immediately	NR-01
Report of trace investigation where waste shipment receipt is not acknowledged within 20 days	10CFR20 App F III.E.2	Written report within 2 weeks following completion of investigation	NR-02
Theft, missing or loss of licensed material in aggregate quantities equal to or greater than 1000 times the quantity specified in Appendix C to 10CFR20.1001-20.2401	10CFR20.2201(a)(1)(i)	Immediately after determining that a loss or theft has occurred (within one hour)	NR-03
Theft, missing or loss of licensed material in quantities greater than 10 times the quantity specified in 10CFR20.1001-20.2401 and the lost or stolen material is still missing 30 days after occurrence becomes known to the licensee	10CFR20.2201(a) (1) (ii)	Within 30 days after the occurrence becomes known to the licensee	NR-03
Follow-up written report on theft or loss of licensed material	10CFR20.2201(b)	Within 30 days after making telephone report of the loss or theft of licensed material	NR-03
Additional substantive information on theft or loss of nuclear material	10CFR20.2201(d)	Within 30 days of receipt of new information	NR-03
Attempt to commit a theft or unlawful diversion of more than 10 curies of tritium at any one time or 100 curies in one calendar year	10CFR30.55(c)	Promptly, to be followed within 15 days by written report	NR-03
Substantive information on attempt to commit a theft or unlawful diversion of more than 10 curies of tritium at any one time or 100 curies in one calendar year	10CFR30.55(c)	Promptly	NR-03
Loss of theft of a sealed radioactive source with an activity greater than the Reportable Quantity as described in 40 CFR 302.5	40CFR302.5	Immediately after determining that a loss of theft has occurred (within one hour)	NR-03

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Event involving byproduct, source or special nuclear material that may cause: ● Exposure (rem) >= 25 TEDE, >= 75 DE (eye), >= 250 rads (skin or any one extremity) ● Release to provide intake > 5X the ALI values of 10CFR20 App. B Table 1, Col. 2	10CFR20.2202(a)	Immediately	NR-04
Event involving loss of control of licensed material by the licensee that may cause: ● Exposure (rem over 24 hrs) > 5 TEDE, > 15 DE (eye), > 50 SDE (skin or any one ext.) ● Release to provide intake > 1X the ALI values of 10CFR20 App. B Table 1, Col. 2	10CFR20.2202(b)	Within 24 hours and 30 day written report	NR-04
Radiological exposure/release in excess of: ● Adult occupational exposure limits (rem): > 5 TEDE, > 50 DDE + CDE (50 years)(any organ except the eye), > 15 DE (eye), > 50 SDE (skin or any one extremity) ● Minor exposure > 10% annual adult occupational exposure limits ● Dose to embryo/fetus of a declared pregnant woman > 0.50 TEDE	10CFR20.2203(a)(2) 10CFR50.73	30 day written report	NR-04
Radiological exposure/release in excess of: ● Dose to member of public > limits of 10CFR20.1301 ● Unrestricted area, Radiation/concentration levels > 10X 10CFR20 or License Limits ● Restricted area, Radiation/concentration levels > License Limits	10CFR20.2203 (a)(2) 10CFR20.2203 (a)(3) 10CFR50.73(a)(2)(viii)	30 day written report	NR-04
Levels of releases of radioactive material in excess of 40 CFR Part 190 limits, in excess of 10 CFR Part 50, Appendix I ALARA design objective exposure limits, or as allowed by the license (See Table NR-4c)	10CFR20.2203(a)(4) 10CFR50.73 10CFR50 App I IV.A.3 ODCM 3.11.1.2 ODCM 3.11.2.2 ODCM 3.11.2.3 ODCM 3.11.4(a) 40CFR190.10 T/S 5.5	Within 30 days after learning of the occurrence; Special Report required by T/S satisfies this requirement	NR-04

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Manufacture, transfer, receipt, disassembly, or disposal of a nationally tracked source as defined in App. E to 10CFR20.	10CFR20.2207(a) thru (g)	Submit a report by the close of the next business day after the transaction.	NR-42
Report of radioactivity in environmental sampling medium at a specified location exceeding levels specified in ODCM Table 3.12-2 (see Table NR-4c)	T/S 5.5 ODCM 3.12.1(b)	Within 30 days after exceeding reporting levels when averaged over any calendar quarter	NR-04
Submit a 30 day report to the NRC for any water sample result for onsite groundwater that is or may be used as a source of drinking water that exceeds the criteria in the Radiological Environmental Monitoring Program for 30 day reporting of offsite water sample results. Copies of the report shall also be provided to the appropriate state agency.	CDF 27408	Within 30 days.	NR-04
Discharge of radioactive material to the environment in excess of ODCM effluent limits and the quantity released in a 24 hour period is > the EPA Reportable Quantity (see Table NR-4c)	ODCM 3.11.1.3(a)	Within 30 days	NR-04
Discharge of radioactive material to the environment in excess of ODCM effluent limits and the quantity released in a 24 hour period is > the EPA Reportable Quantity (see Table NR-4c)	40CFR302 ODCM 3/4.11.1.1 ODCM 3/4.11.1.2 ODCM 3/4.11.2.1 ODCM 3/4.11.2.2 ODCM 3/4.11.2.3	Immediately	NR-04
Discharge of radioactive gaseous waste without treatment and in excess of specified limits (see Table NR-4c)	ODCM 3/4.11.2.4	Within 30 days	NR-04

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Bodily injury or property damage out of or in connection with the possession or use of the radioactive material at the location or in transportation or in the event any insurance claim is made.	10CFR140.6 (a)	As promptly as practical	NR-04
Failure to comply or existence of a defect causing a substantial safety hazard	10CFR21.21(a)(2)	Interim report within 60 days of discovery. Notify Resp Officer within 5 days of Eval completion. Fax/Call NRC Ops Center within 2 days of notifying Resp Officer. Final report within 30 days of notifying Resp Officer.	NR-05
Failure to comply or existence of a deviation discovered by CPNPP in a basic component sold to other utilities.	10CFR21.21(b)	If the capability to perform the evaluation does not exist, CPNPP shall inform purchasers within 5 working days of this determination.	NR-05
Significant Fitness-for-Duty events: ● Sale, use, possession in protected area ● Licensed operator/supervisor involved in sale, use, possession of alcohol or illegal drugs	10CFR26.719	Within 24 hours of the discovery	NR-06
Drug and alcohol testing errors: ● false positive error on blind performance specimen or false negative on QA validity check ● unsatisfactory performance testing result	10CFR26.719(c)	Within 24 hours of the discovery (false positive or negative) or 30 days (unsatisfactory performance test results)	NR-06

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
NRC employee believed to be under the influence of any substance or otherwise unfit for duty	10CFR26.77(c)	Immediately	NR-07
Notification of information, having a significant impact on public health and safety or common defense and security.	10CFR50.9(b) 10CFR30.9(b) 10CFR40.9(b) 10CFR54.13(b) 10CFR55.9 10CFR70.9(b) 10CFR71.7(b) 10CFR72.11(b) 10CFR110.7a(b)	Within 2 working days of identification.	NR-08
Sealed source or fission detector leakage report	ODCM 4.7.15.3	Annually (with annual Radioactive Effluent Report)	NR-09
Failure Damage to Source Shielding/On-Off Mechanism or indicator	10CFR31.5(c)(5)	30 day written report	NR-09
Changes or errors in ECCS evaluation model, or in the application of ECCS model that affects Peak Fuel Cladding Temperature (FCT) calculation	10CFR50.46(a)(3)(ii)	Written report at least annually. Written report within 30 days if calculated Peak FCT changes more than 50 degrees F.	NR-10
Reactor is in a safe stable condition (after damage)	10CFR50.54(w)(4)(ii)	Prompt written notification	NR-11
Cleanup plan to decontaminate reactor	10CFR50.54(w)(4)(ii) 10CFR50.2	Written report within 30 days of restoring reactor to a safe and stable condition	NR-11

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Close out or reduction of emergency classification	NUREG-0654 App I	Written report 8 or 24 hours, depending on classification	NR-11
Declaration of an Emergency to State and Local Agencies	10CFR50 App E IV.D.3	Within 15 minutes after declaration	NR-13
Declaration of any Emergency class specified in the CPNPP Emergency Plan to NRC	10CFR50.72(a)(1)(i)	Immediately following notification of appropriate state/local agencies; no later than 1 hour after declaration of an emergency class.	NR-13
EPP-201, "Assessment of Emergency Action Levels, Emergency Classification and Plan Activation,"	10CFR72.32(a)(8)	Within 1 hour	NR-13
Failure of a PORV or Safety Valve to close	NUREG 0694	Within 1 hour after valve failure	NR-13
Notification of certain emergency events described in 10CFR50.72(a)(i) ● The declaration of any of the Emergency Classes specified in the licensee's approved Emergency Plan ● Those non-emergency events specified in paragraph (b) of this section that occurred within three years of the date of discovery.	10CFR50.72(a)(i) 10CFR72.75(a)	Immediately via ENS, less than 1 hour of occurrence	NR-13

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Notification of certain non-emergency events described in 10CFR50.72(b) (1): ● If not reported as a declaration of an Emergency Class under paragraph (a), NRC shall be notified as soon as practical and in all cases within one hour of the occurrence of any deviation from the plant's TS authorized pursuant to 10CFR50.54(X)	10CFR50.72(b)(1)	Within 1 hour	NR-13
Notification of certain events, conditions and releases described in 10CFR50.72(b) (2): • Initiation of any nuclear plant shutdown required by TS i.e., performance of any action to start reducing power to achieve an operational condition or mode that requires the reactor to subcritical, as a result of a TS requirement (e.g., LCO 3.0.3)	10CFR50.72(b)(2)(i)	Within 4 hours of occurrence via ENS	NR-13
• Any event that results or should have resulted in emergency core cooling system (ECCS) discharge into the reactor coolant system (RCS)as a result of a valid signal except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation.	10CFR50.72(b)(2)(iv)(A)	Within 4 hours of occurrence via ENS	NR-13
• Any event or condition that results in actuation of the reactor protection system (RPS) when the reactor is critical except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation.	10CFR50.72(b) (2) (iv) (B)	Within 4 hours of occurrence via ENS	NR-13

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Notification of certain events, conditions and releases described in 10CFR50.72(b) (2): • Any event or situation, related to the health and safety of the public or onsite personnel, or protection of the environment, for which a news release is planned or notification to other government agencies has been or will be made. Such an event may include an onsite fatality or inadvertent release of radioactively contaminated materials.	10CFR50.72(b)(2)(xi)	Within 4 hours of occurrence via ENS	NR-13
Notification of certain events, conditions and releases described in 10CFR50.72(b) (3):			
• Any event or condition that results in: The condition of the nuclear power plant, including its principal safety barriers, being seriously degraded; or the nuclear power plant being in an unanalyzed condition that significantly degrades plant safety.	10CFR50.72(b)(3)(ii)(A) and (B)	Within 8 hours via ENS	NR-13
• Any event or condition that results in <u>valid</u> actuation of any of the systems listed below, except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation: - Reactor protection system (RPS) including: reactor scram and reactor trip. Actuation of the RPS when the reactor is critical is reportable within 4 hours per 10CFR50.72(b)(2)(iv)(B). - General containment isolation signals affecting containment isolation valves in more than one system or multiple main steam isolation valves (MSIVs). - Emergency core cooling systems (ECCS) for pressurized water reactors (PWRs) including: high-head, intermediate-head, and low-head injection systems and the low pressure injection function of residual (decay) heat removal systems. - PWR auxiliary or emergency feedwater system.	10CFR50.72(b)(3)(iv)(A) and (B)	Within 8 hours via ENS	NR-13

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
(Continued from previous page) - Containment heat removal and depressurization systems, including containment spray and fan cooler systems. - Emergency ac electrical power systems, including: emergency diesel generators (EDGs)	10CFR50.72(b) (3)(iv)(A) and (B)	Within 8 hours via ENS	NR-13
• Any event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident.	10CFR50.72(b)(3)(v) 10CFR50.72(b)(3)(vi)	Within 8 hours via ENS	NR-13
• [Events covered in paragraph (b)(3)(v) of this section may include one or more procedural errors, equipment failures, and/or discovery of design, analysis, fabrication, construction, and/or procedural inadequacies. However, individual component failures need not be reported pursuant to paragraph (b)(3)(v) of this section if redundant equipment in the same system was operable and available to perform the required safety function.]			NR-13
• Any event requiring the transport of a radioactively contaminated person to an offsite medical facility for treatment.	10CFR50.72(b)(3)(xii)	Within 8 hours via ENS	NR-13
• event that results in a major loss of emergency assessment capability, offsite response capability, or offsite communications capability (e.g., significant portion of control room indication, emergency notification system, or offsite notification system).	10CFR50.72(b) (3) (xiii)	Within 8 hours via ENS	NR-13

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Follow-up to the phone notification made under 10CFR50.72 (a) and (b), report: ● Any further degradation in the level of safety of the plant or worsening plant conditions including: ● Declaration of Emergency Classes ● Changes in Emergency Class ● Termination of Emergency Class	10CFR50.72(a)(1)	Immediately via ENS	NR-13
Follow-up to the phone notification made under 10CFR50.72(a) and (b), report: ● Results of evaluations or assessments of the plant conditions ● Effectiveness of response or protective measures taken ● Plant Behavior that is not understood.	10CFR50.72(c)(2)	Immediately via ENS	NR-13
Notification of Events in 10CFR50.73(a)(2):			
● T/S required shutdown completion (to Mode 3)	10CFR50.73(a)(2)(i)(A)	60 day written report	NR-13
● Operation/condition prohibited by T/S	10CFR50.73(a)(2)(i)(B)	60 day written report	NR-13
● Deviation from T/S to 10CFR50.54(x)	10CFR50.73(a)(2)(i)(C)	60 day written report	NR-13
● Serious degradation in plant/safety barriers	10CFR50.73(a)(2)(ii)(A)	60 day written report	NR-13
● Plant in condition unanalyzed, that significantly degraded plant safety	10CFR50.73(a)(2)(ii)(B)	60 day written report	NR-13
● Natural phenomenon or condition which threatened safe plant operation	10CFR50.73(a)(2)(iii)	60 day written report	NR-13

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Notification of events in 10CFR50.73(a)(2) ***(continued):***			
• Event/Condition resulted in manual/automatic actuation of the listed systems	10CFR50.73(a)(2)(iv)(A/B)	60 day written report	NR-13
• Condition/Event which could prevent shutdown, residual heat removal, control of releases, or mitigation of an accident	10CFR50.73(a)(2)(v)	60 day written report	NR-13
• Any event where a single cause or condition caused at least one independent train or channel to become inoperable in multiple systems or two independent trains or channels to become inoperable in a single system designed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident	10CFR50.73(a)(2)(vii)	60 day written report	NR-13
Notification of events in 10CFR50.73(a) (2): • Airborne releases in unrestricted area >20X 10CFR20, Appendix B, Table 2 Column 1 • Liquid releases > 20X 10CFR20, Appendix B, Table 2, Column 2 except H3 and dissolved noble gases • Actual threat to plant safety or hampers site personnel	10CFR50.73(a)(2)(viii)	60 day written report	NR-13
• Any event or condition that as a result of a single cause could have prevented the fulfillment of a safety function for two or more trains or channels in different systems that are needed to: *(1)* Shut down the reactor and maintain it in a safe shutdown condition; *(2)* Remove residual heat; *(3)* Control the release of radioactive material; or *(4)* Mitigate the consequences of an accident	10CFR50.73(a)(2)(ix)(A)	60 day written report	NR-13

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
• Events covered in paragraph (ix)(A) of this section may include cases of procedural error, equipment failure, and/or discovery of a design, analysis, fabrication, construction, and/or procedural inadequacy. However, it is not required to report an event pursuant to paragraph (ix)(A) of this section if the event results from: *(1)* A shared dependency among trains or channels that is a natural or expected consequence of the approved plant design; or *(2)* Normal and expected wear or degradation.	10CFR50.73(a)(2)(ix)(B)	60 day written report	NR-13
Submit supplemental information as a supplement to a previously submitted LER	10CFR50.73(c)	As specified in the LER	NR-13
Notification of change in licensed operator status (reassignment, termination or permanent disability)	10CFR50.74(a) 10CFR50.74(b) 10CFR50.74(c) 10CFR55.21 10CFR55.25	Written report within 30 days of learning of or change of diagnosis	NR-14
Felony conviction of a licensed operator	10CFR55.53(g) 10CFR55.5(b)(2)(iv)	Written report within 30 days	NR-15
Accidental criticality or loss or theft or attempted theft of special nuclear material.	10CFR70.52(a) 10CFR73.71(a) 10CFR74.11(a) 10CFR72.74(a)	Within 1 hour after discovery and written report within 60 days	NR-16
Accidental criticality or loss or theft or attempted theft of special nuclear material.	10CFR72.74(a)	Within 1 hour after discovery	NR-16

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Accident notification required by DOT on transportation of hazardous or licensed material (including loading, unloading, temporary storage). Note: If material is radioactive waste within the state of Texas, notification of the Texas Department of State Health Services and local emergency planning committee where the accident occurred is also required. As a direct result of a hazardous material— • A person is killed; • A person receives an injury requiring admittance to a hospital; • The general public is evacuated for one hour or more; • A major transportation artery or facility is closed or shut down for one hour or more; or • The operational flight pattern or routine of an aircraft is altered; Fire, breakage, spillage, or suspected radioactive contamination occurs involving a radioactive material A situation exists of such a nature (*e.g.* , a continuing danger to life exists at the scene of the incident) that, in the judgment of the person in possession of the hazardous material, it should be reported to the National Response Center (NRC) even though it does not meet the criteria of paragraphs above.	10CFR71.5(a)(1)(v) 40CFR302.6 49CFR171.15 49CFR171.16 25TAC289.257	Earliest practicable moment but not later than 12 hours and 30 day written report	NR-17
Any instance of significant reduction in the effectiveness of authorized packaging during use or details of any defects with safety significance in nuclear material packaging	10CFR71.95	Written report within 60 days of occurrence	NR-18
Reporting of Mishaps to Low-Level Radioactive Waste (LLW) Forms prepared for disposal (Voluntary reports requested by NRC)	GL 91-02 STA-709, Sec. 6.8	Within 30 days of the incident	NR-18

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Advance notification of certain shipments of nuclear waste (see exceptions in rule)	10CFR71.97(c) 10CFR71.97(a) 10CFR71.97(b) 10CFR71.97(d)	If by mail, shall be postmarked 7 days prior to beginning of 7 day period of expected shipment. If by messenger, shall arrive 4 days prior to the 7 day period.	NR-19
Revised schedule information concerning shipment of nuclear waste	10CFR71.97(e) 10CFR71.97(f)	As schedule changes	NR-19
Notice of cancellation of shipment (if noticed in advance) of nuclear waste	10CFR71.97(f)	Upon cancellation of shipment	NR-19
Advance notification of shipment of spent fuel within or through a state	10CFR73.37(f)	If sent by mail, postmarked 7 days before the shipment. If delivered by messenger, 4 days before the shipment.	NR-19
Notification of schedule changes of more than six hours for transportation of spent fuel	10CFR73.37(f)(4)	Immediately upon determination of schedule change	NR-19
Notice of change of shipment itinerary for special nuclear materials	10CFR73.72(a)(5)	Immediately	NR-19
Security arrangements for shipments of SNM	10CFR73.26(b)(3) 10CFR73.72 (a)(2)	Prior to 10 day advance notice of shipment	NR-19
Notify the NRC of any shipment of low or moderate strategic SNM determined to be lost or unaccounted for. Notify the NRC after recovery of or accounting for the shipment.	10CFR73.67(e)(3)(vi) 10CFR73.67(e)(3)(vii) 10CFR73.67(g)(3)(iii) 10CFR73.71(a)	Within 1 hour of discovery; and within 1 hour after recovery of or accounting for the shipment; followed by a written report within 30 days of the initial telephone notification	NR-20

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Significant supplementary information arising after initial NRC notification or written report; revised reports	10CFR73.71(a)(5) 10CFR73.71(b)(2)	Immediately	NR-20
Notification of failure to receive periodic calls during SNM shipment by road or rail	10CFR73.26(i)(6) 10CFR73.26(k)(4) 10CFR72.3	Immediately	NR-20
Notification that shipment of SNM of moderate strategic significance has arrived at its destination (purpose is to confirm the integrity of the shipment at time of receipt or exit from the U.S.)	10CFR73.67(e)(7)(ii)	Within 24 hours after arrival of shipment at final destination	NR-21
Actual or credible threat to commit or cause a theft or unlawful diversion of special nuclear material	10CFR73.71(b) 10CFR73 App G I.a.1 10CFR73 App G I.a.2	Within 1 hour of discovery	NR-22
Actual or credible threat to commit or cause damage to the plant or transportation system.	10CFR73.71(b)	Within 1 hour of discovery	NR-22
Actual or credible threat to commit or cause interruption of normal operation of the plant	10CFR73.71(b) 10CFR73 App G I.a.3	Within 1 hour of discovery	NR-22
Actual entry of unauthorized person into a protected area, material access area, controlled access area, vital area, or transport	10CFR73.71(b) 10CFR73 App G I.b	Within 1 hour of discovery	NR-22
Any failure, degradation or discovered vulnerability in a safeguard system that could allow unauthorized or undetected access to a protected area, material access area, controlled access area, vital area, or transport	10CFR73.71(b) 10CFR73 App G I.c	Within 1 hour of discovery	NR-22
Actual or attempted introduction of contraband (dangerous weapon, explosive or other dangerous instrument/material) into a protected area, material access area, controlled access area, vital area, or transport	10CFR73.71(b) 10CFR73 App G I.d	Within 1 hour of discovery	NR-22

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Follow-up report (Safeguard Event) on NRC Form 366 (Form 366 available from www.nrc.gov)	10CFR73.71(2)(d) 10CFR73.71(a)(4) 10CFR73 App G I.a 10CFR73 App G I.b 10CFR73 App G I.c 10CFR73 App G I.d 10CFR50.73	Within 60 days	NR-22
TCEQ-TPDES Non-Compliance 24-hour reporting	TCEQ-TPDES Permit	24 hours and written report within 5 working days after occurrence	NR-23
Environmental Matters ● Air emission upset ● Dam inspection ● Fish die-off/impingement ● Oil/chemical spill ● Water discharge permit excursion ● PCB spills ● Asbestos releases	LP Env Svc QRGFEM	As soon as practical (verbal and/or written notification)	NR-23
Environmental Matters ● Renovations and demolition of friable asbestos ● Drinking water exceeding maximum contaminant level for Coliform bacteria ● Discharge of oil or hazardous substance into navigable waterways	LP Env Svc QRGFEM	As soon as practical (verbal and/or written notification)	NR-23
Accident Monitoring Instrumentation-Cnt area rad mon (with one (two) inoperable, restore the inoperable channel to operable w/I 30 (7) days or prepare report)	T/S 3.3.3 T/S 5.6.8	14 days	NR-24
Accident Monitoring Instrumentation - RVLIS (with one (two) channel inoperable, restore w/I 30 (7) days or prepare report)	T/S 3.3.3 T/S 5.6.8	Within 30 days	NR-24
S/G Tube Inspection Report (Model D76 & D5 SGs)	T/S 5.6.9	Within 180 days of entering Mode 4.	NR-24

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Site access for gas/oil exploration/drilling	NPF-87, 2.F(3) NPF-89, 2.F(3) FSAR 2.1.2 SER 2.1.2 10CFR50.71(a)	Promptly	NR-26
Unusual or important environmental events such as: ● Excessive bird impactions ● Plant or animal disease ● Outbreaks, unusual occurrences of protected species ● Fish kills	EPP 4.1 EPP 5.4.2	24 hours and 30 day written report	NR-27
Unusual or important environmental events such as: ● Increase in nuisance organisms or conditions ● Unanticipated/Emergency discharge or waste water/chemical substance	EPP 4.1 EPP 5.4.2	24 hours and 30 day written report	NR-27
Water treatment facility outages exceeding 30 days	EPP 4.2.2	As Required (Within 15 days after a determination of the extended outage is made)	NR-28
Information required when dome lights are inoperable or become operable (a notification to the NRC is not required)	FAA Clearance #76-SW-1433-OE	Within 30 minutes of occurrence	NR-29
Accident to Nuclear Boiler	Texas Dept. Of Licensing & Regulation -Boiler Division, Title 16, Part 4, Chapter 65, Rule 65.100(j)(10) of the Texas Admin Code	Immediately	NR-31
Bankruptcy	10 CFR 50.54(cc)	Immediately	NR-34

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Test methods for supplemental fracture toughness tests.	10CFR50 App G III.B	Requires submittal to and approval by the Director, NRR prior to testing.	NR-35
Update of projected values for reference temperature for pressurized thermal shock for reactor vessel beltline materials.	10CFR50.61(b) (1)	Following a significant change in projected values.	NR-36
Application for use of respiratory protection equipment that has not been tested or certified by NIOSH/MSHA	10CFR20.1703(a) (2)	As needed, requires prior authorization/approval from NRC before equipment use.	NR-37
Analytical evaluations of exam results as required by IWB/IWC 3132.4 shall be submitted to the regulatory authority.	ASME Section XI IWB-3134(b) IWC-3134(b)	As promptly as practical	NR-38
An event that is driven by violation, incursion or deviation from current ICM, special Regulatory Information Summary (RIS) or other regulatory requirement(s) associated with elevated security levels as identified by the NRC or Office of Homeland Security. This includes the necessity to implement required actions noted for a given event identified below:	14 CFR 99.7 or FDC 1/3352 or A0069/02	Within 1 hour and development of a written Security Field Report and logging in the Security Log as required in NR-39. Contact the FAA, FBI and Somervell Sheriff Department as required by NR-39.	NR-39

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Loggable Event • If the aircraft seems to be too low (<500 feet) or close to a facility structure (< 1000 feet) or is circling, loitering or not meeting the FAA advisory(s) for less than 3 to 5 minutes, *and* does not meet the Deminimus criteria noted in NR-39. • If the pipeline flyover flight is not done on its regular schedule *and* occurs without prior notification.	Memorandum of Understanding between NRC, Region IV, and Luminant Power	Within 1 hour develop a Security Field Report as required by NR-39	NR-39
Reportable Event • If the vehicle performs outwardly potentially threatening actions or functions, or continues to loiter, circle or reduces altitude/speed. • An aircraft lands via affixed flotation devices or crashes into Squaw Creek Reservoir. • If the flight seems to be too low or close to a facility structure (within 500 feet), a call to the FAA should be made to report the aircraft flight pattern not consistent with FAA flight rules/restrictions *and* no outward threatening action on the part of the aircraft was noted.	14CFR99.7 or FDC-V3352 or A0069/02	Within 1 hour contact the NRC, FAA, FBI, and Somerville Sheriff's Department as required by NR-39	NR-39

REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Suspension of Security Measures due to Inclement Weather	CPNPP Security Plan	CPNPP shall notify the NRC Ops Center as soon as practical and in all cases within one hour of the occurrence. The affected NRC Regional Office shall be notified as soon as practical. Upon restoration of the affected security measures, the NRC Ops Center and the affected NRC Regional Office shall be notified as soon as practical.	NR-40
ERCOT/NERC/DOE Reports			NR-41
Reportable events are: 1. Total generation loss, within one minute, of ≥ 1,000 MW in the ERCOT Interconnection [i.e., a reactor trip]. 2. Damage or destruction of its Facility that results from actual or suspected intentional human action; or 3. Physical threat to its Facility, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility; or 4. Suspicious device or activity at a facility. Do not report theft unless it degrades normal operation of a Facility.	Luminant Corporate Procedure G-3025	The Control Room shall notify the Qualified Scheduling Entity (QSE) at 214-875-9778 as soon as practicable for items 1 through 10.	

(Continued on next page)

REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
5. Failure to Trip During Fault - Any failure of a Protection System to operate for a Fault within the zone it is designed to protect. The failure of a protection System components is not a Misoperation as long as the overall performance of the protection System for the Element is designed to protect is correct; 6. Failure to Trip Other Than Fault - A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct; 7. Slow Trip During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect; 8. Slow Trip Other than Fault - A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate; 9. Unnecessary Trip During a Fault - Any unnecessary Protection System operation for a fault not within the intended zone of protection; 10. Unnecessary Trip Other Than Fault – Any unnecessary Protection System operation when no fault or other abnormal condition has occurred;	Luminant Corporate Procedure G-3035	The Control Room shall notify Oncor at 214-743-6920/6921 as soon as practicable for items 5 through 10 per Att. 2 of IPO-009A/B. The Control Room shall notify Meter & Relay of a potential NERC relay misoperation for items 5 through 10 per Att. 2 of IPO-009A/B.	NR-41

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Provide verbal and e-mail notification to the designated Luminant Generation Compliance contacts below upon notification of a suspected ERCOT Restricted Systems access violation per STA-913, Attachment 8.C and copy the Manager, Regulatory Affairs. Email Address/Phone Number Rick.Terrill@Luminant.com 214-875-8750 Duane.Steward@Luminant.com 214-875-8726 Bobby.Crump@Luminant.com 214-875-8745	ERCOT Protocol 16.14	As soon as possible.	NR-43
Any of the fuel specifications or loading conditions in CoC Appendix B, Section 2.1 are violated.	HI-STORM 100 System CoC 1014, Appendix B, Section 2.2.2	Within 24 hours	NR-44
Any of the fuel specifications or loading conditions in CoC Appendix B, Section 2.1 are violated.	HI-STORM 100 System CoC 1014, Appendix B, Section 2.2.3	Within 30 days	NR-44
Declaration of an emergency as specified in the emergency plan.	10CFR72.75(a)	Within 1 hour	NR-13

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
An action taken in an emergency that departs from a condition or a technical specification contained in a license or certificate of compliance issued under this part when the action is immediately needed to protect the public health and safety, and no action consistent with license or certificate of compliance conditions or technical specifications that can provide adequate or equivalent protection is immediately apparent.	10CFR72.75(b)(1)	Within 4 hours	NR-45
Any event or situation related to the health and safety of the public or onsite personnel, or protection of the environment, for which a news release is planned or notification to other Government agencies has been or will be made. Such an event may include an onsite fatality or inadvertent release of radioactively contaminated materials.	10CFR72.75(b)(2)	Within 4 hours	NR-46
A defect in any spent fuel, HLW, or reactor-related GTCC waste storage structure, system, or component that is important to safety.	10CFR72.75(c)(1)	Within 8 hours	NR-47

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
A significant reduction in the effectiveness of any spent fuel, HLW, or reactor-related GTCC waste storage confinement system during use	10CFR72.75(c)(2)	Within 8 hours	NR-48
Any event requiring the transport of a radioactively contaminated person to an offsite medical facility for treatment.	10CFR72.75(c)(3)	Within 8 hours	NR-49

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
An event in which important to safety equipment is disabled or fails to function as designed when: (i) The equipment is required by regulation, license condition, or certificate of compliance to be available and operable to prevent releases that could exceed regulatory limits, to prevent exposures to radiation or radioactive materials that could exceed regulatory limits, or to mitigate the consequences of an accident; and (ii) No redundant equipment was available and operable to perform the required safety function.	10CFR72.75(d)(1)	Within 24 hours*	NR-50

* For notifications made under this paragraph, CPNPP may delay the notification to the NRC if the end of the 24-hour period occurs outside of the NRC's normal working day (i.e., 7:30 a.m. to 5:00 p.m. Eastern time), on a weekend, or a Federal holiday. In these cases, the licensee shall notify the NRC before 8:00 a.m. Eastern time on the next working day.

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
Unauthorized entry to the security zone for Category 1 or 2 quantities of radioactive material resulting in attempted theft, sabotage or diversion of the radioactive material.	10 CFR 37.57(a)(c)	Immediately following notification of LLEA and in no case greater than 4 hours and 30 day written report.	NR-51
As appropriate, assessment results of suspicious activity related to possible theft, sabotage or diversion of Category 1 or 2 radioactive materials.	10 CFR 37.57(b)	Immediately following notification of LLEA and in no case greater than 4 hours.	NR-51
Determination that a shipment of Category 1 quantity of Radioactive Material is lost or missing.	10 CFR 37.81(a) (g)	Within 1 hour and 30 day written report.	NR- 51
Determination that a shipment of Category 2 quantity of Radioactive Material is lost or missing.	10 CFR 37.81(b) (g)	Within 4 hours and 30 day written report.	NR- 51
Discovery of any actual or attempted theft or diversion of a shipment or suspicious activities related to the theft or diversion of a shipment of a category 1 quantity of radioactive material.	10 CFR 37.81(c) (g)	As soon as possible and 30 day written report. Suspicious activity does not require written report.	NR- 51
Discovery of any actual or attempted theft or diversion of a shipment or suspicious activities related to the theft or diversion of a shipment of a category 2 quantity of radioactive material.	10 CFR 37.81(d) (g)	As soon as possible and 30 day written report. Suspicious activity does not require written report.	NR- 51
Recovery of any lost or missing Category 1 or 2 Radioactive Material	10 CFR 37.81(e) (f)	As soon as possible	NR- 51
Additional substantive information on loss or theft or category 1 or 2 radioactive materials.	10 CFR 37.81(h)	Within 30 days of learning of additional information.	NR-51
Work-related fatality.	29CFR1904.39	Within 8 hours.	NR-52

REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
After discovery of a cyber attack that adversely impacted safety-related or important-to-safety functions, security functions, or emergency preparedness functions (including off-site communications); or that compromised support systems and equipment resulting in adverse impacts to safety, security or emergency preparedness functions within the scope of 10 CFR 73.54.	10 CFR 73.77(a)(1) 10 CFR 73.77(d) 10 CFR 73.77(d)(3)	Within 1 hour and written security report within 60 days (using Form 366/366A)	NR-53
After discovery of a cyber attack that could have caused an adverse impact to safety-related or important-to-safety functions, security functions, or emergency preparedness functions (including offsite communications); or that could have compromised support systems and equipment, which if compromised, could have adversely impacted safety, security, or emergency preparedness functions within the scope of 10 CFR 73.54	10 CFR 73.77(a)(1) 10 CFR 73.77(d) 10 CFR 73.77(d)(3)	Within 4 hours and written security report within 60 days (using Form 366/366A)	NR-53
After discovery of a suspected or actual cyber attack initiated by personnel with physical or electronic access to digital computer and communication systems and networks within the scope of 10 CFR 73.54.	10 CFR 73.77(a)(1) 10 CFR 73.77(d) 10 CFR 73.77(d)(3)	Within 4 hours and written security report within 60 days (using Form 366/366A)	NR-53
After notification of a local, State, or other Federal agency of an event related to implementation of the licensee's cyber security program for digital computer and communication systems and networks within the scope of 10 CFR 73.54 that does not otherwise meet a notification under 10 CFR 73.77(a).	10 CFR 73.77(a)(2)(iii)	Within 4 hours	NR-53

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REPORT	SOURCE OF REQUIREMENT	TIMING	REFER TO NONROUTINE REPORT DESCRIPTION
After receipt or collection of information regarding observed behavior, activities, or statements that may indicate intelligence gathering or pre-operational planning related to a cyber attack against digital computer and communications systems and networks within the scope of 10 CFR 73.54.	10 CFR 73.77(a)(3)	Within 8 hours	NR-53
Use corrective action program (CAP) to record vulnerabilities, weaknesses, failures, and deficiencies in the cyber security program as well as record notifications made under paragraph (a) of 10 CFR 73.77.	10 CFR 73.77(b)	Within 24 hours	NR-53

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ATTACHMENT 8.C

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ATTACHMENT 8.D/1

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NONROUTINE REPORT - 1

TITLE: External Contamination on Packages of Radioactive Material

FORMAT: Immediate notification by telephone and telegraph, mailgram, or facsimile to the Administrator of the NRC Region IV office and to the final delivering carrier.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR20.1906

(a) Each licensee who expects to receive a package containing quantities of radioactive material in excess of a Type A quantity, as defined in 10CFR 71.4 and Appendix A to Part 71 of this chapter, shall make arrangements to receive--

(1) The package when the carrier offers it for delivery; or

(2) Notification of the arrival of the package at the carrier's terminal and to take possession of the package expeditiously.

(b) Each licensee shall monitor the external surfaces of a package known to contain radioactive contamination and radiation levels if the package--

(1) Is labeled as containing radioactive material; or

(2) Has evidence of potential contamination, such as packages that are crushed, wet, or damaged.

(c) The licensee shall perform the monitoring required by paragraph (b) of this section as soon as practicable after receipt of the package, but not later than 3 hours after the package is received at the licensee's facility if it is received during the licensee's normal working hours, or not later than 3 hours from the beginning of the next working day if it is received during the licensee's normal working hours, or not later than 3 hours from the beginning of the next working day if it is received after working hours.

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(d) The licensee shall immediately notify the final delivery carrier and, by telephone and telegram, mailgram, or facsimile, the Administrator of the appropriate NRC Regional Office listed in appendix D to 10CFR20.1001-20.2401 when:

(1) Removable radioactive surface contamination exceeds the limits of 10CFR71.87(i) of this chapter; or

(e) Each licensee shall:

From 10CFR20.1906

(1) Establish, maintain, and retain written procedures for safely opening packages in which radioactive material is received; and

(2) Ensure that the procedures are followed and that due consideration is given to special instructions for the type of package being opened.

(f) Licensees transferring special form sources in licensee-owned or licensee-operated vehicles to and from a work site are exempt from the contamination monitoring requirements of paragraph (b) of this section, but are not exempt from the survey requirement in paragraph (b) of this section for measuring radiation levels that are required to ensure that the source is still properly lodged in its shield.

CONTENT: As requested during notification.

ADDITIONAL INFORMATION: RPI-202, "Receipt of Radioactive Material," provides instruction for notifying the Shift Manager if radiation or contamination levels exceed those specified.

CONTROL ROOM ACTIONS: The Shift Manager shall perform immediate telephone notification and telegraph, mailgram or facsimile to Region IV Administrator and to final delivering carrier.

FOLLOWUP ACTIONS: None

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NONROUTINE REPORT -2

TITLE:	Failure to Receive Waste Shipment Receipt Acknowledgment
FORMAT:	Written report to be filed with NRC Region IV within two (2) weeks of completion of trace investigation.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	This is a paraphrased summary only. Refer to source documents listed in Attachment 8.B. From 10CFR20 Appendix F(E) Any shipment or part of a shipment for which acknowledgment is not received within the times set forth in this section must: (1) Be investigated by the shipper if the shipper has not received notification of receipt within 20 days after transfer; and (2) Be traced and reported. The investigation shall include tracing the shipment and filing a report with the nearest Commission Regional Office listed in appendix D to this part. Each licensee who conducts a trace investigation shall file a written report with the appropriate NRC Regional office within 2 weeks of completion of the investigation.
CONTENT:	The written report shall provide information resulting from the investigation.
ADDITIONAL INFORMATION:	None
CONTROL ROOM ACTIONS:	None

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NONROUTINE REPORT -2

FOLLOWUP ACTIONS: The Radiation Protection Manager shall ensure the written report is prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 3

TITLE: Theft, Loss, or Missing Licensed Material

FORMAT: Notification of the NRC Operation Center via the ENS immediately after the determination.

Written followup report within 30 days; additionally, subsequent to filing the written report, report in writing any substantive additional information on the loss or theft which becomes available within 30 days after learning of such information.

Immediate telephone notification to EPA National Response Center for 40CFR requirements.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR20.2201(a)

(i) Each licensee shall report to the Commission, by telephone immediately after its occurrence becomes known to the licensee, any lost, stolen, or missing licensed material in an aggregate quantity equal to or greater than 1,000 times the quantity specified in appendix C to 10CFR20.1001-20.2401, under such circumstances that it appears to the licensee that an exposure could result to persons in unrestricted areas.

(ii) Within 30 days after the occurrence of any lost, stolen, or missing licensed material becomes known to the licensee, all licensed material in a quantity greater than 10 times the quantity specified in appendix C to 10CFR20.1001-20,2401 that is still missing at this time.

From 10CFR20.2201(b)

Each licensee who makes a report under Paragraph (a) of this section shall, within 30 days after learning of the theft or loss, make a report in writing to the NRC.

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From 10CFR20.2201(d)

Subsequent to filing the written report, the licensee shall also report any additional substantive information on the loss or theft within 30 days after the licensee learns of such information.

From 10CFR30.55(c)

Except as specified in paragraph (d) of this section, each licensee who is authorized to possess tritium shall report promptly to the appropriate NRC Regional Office listed in appendix D of part 20 of this chapter by telephone and telegraph, mailgram, or facsimile any incident in which an attempt has been made or is believed to have been made to commit a theft or unlawful diversion of more than 10 curies of such material at any one time or more than 100 curies of such material in any one calendar year. The initial report shall be followed within a period of fifteen (15) days by a written report submitted to the appropriate NRC Regional Office which sets forth the details of the incident and its consequences. Copies of such written report shall be sent to the Director, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555. Subsequent to the submission of the written report required by this paragraph, the licensee shall promptly inform the Office of Nuclear Material Safety and Safeguards by means of a written report of any substantive additional information, which becomes available to the licensee, concerning an attempted or apparent theft or unlawful diversion of tritium.

From 10CFR74.11(a)

Each licensee who possesses one gram or more of contained uranium-235, uranium-233, or plutonium shall notify the NRC Operations Center within one hour of discovery of any loss or theft or other unlawful diversion special nuclear material which the licensee is licensed to possess, or any incident in which an attempt has been made to commit a theft or unlawful diversion of special nuclear material. The requirement does not pertain to measured discards or inventory difference quantities.

From 40CFR302

Notify the EPA National Response Center immediately after the determination of the loss or theft of a sealed radioactive source with an activity greater than the EPA Reportable Quantity (RQ) as defined in 40CFR302.5.

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CONTENT: From 10CFR20.2201(b)
The report shall include the following information:

1) A description of the licensed material involved, including kind, quantity, chemical and physical form;
2) A description of the circumstances under which the loss or theft occurred;
3) A statement of disposition or probable disposition of the licensed material involved;
4) Exposure of individuals to radiation, circumstances under which the exposure(s) occurred, and the possible total effective dose equivalent to persons in unrestricted areas.
5) Actions which have been taken, or will be taken, to recover the material; and
6) Procedures or measures which have been or will be adopted to prevent a recurrence of the loss or theft of licensed material.

From 10CFR20.2201(c)

Any report filed with the Commission pursuant to this section shall be so prepared than names of individuals who may have received exposure to radiation are stated in a separate and detachable part of the report.

ADDITIONAL INFORMATION: From 10CFR74.11

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(b) This notification must be made to the NRC Operations Center via the Emergency Notification System if the licensee is party to that system. If the Emergency Notification System is inoperative or unavailable, the licensee shall make the required notification via commercial telephonic service or other dedicated telephonic system or any other method that will ensure that a report is received by the NRC Operations Center within one hour. The exemption of 10CFR73.21(g)(3) [protection of Safeguards information under emergency conditions] applies to all telephonic reports required by this section.

(c) Reports required under 10CFR73.71 need not be duplicated under requirements of this section.

Events reported in accordance with 10CFR50.73 need not be reported by duplicate report under 10CFR20.2201 Subpart M-Reports.

This report also meets the reporting requirements of 10CFR75.36 if CPNPP is designated by written notification from the Commission as an International Atomic Energy Agency safeguards facility pursuant to 10CFR75.41.

EPA National Response Center telephone numbers:
(800) 424-8802
(202) 267-2675 (backup)

STA-652, "Radioactive Material Control," RPI-212, "Radioactive Source Control," and NUC-020, “Special Nuclear Material Accountability Plan,” provide instructions for notifying the Shift Manager in the event of a loss or theft of licensed material.

CONTROL ROOM ACTIONS:

The Shift Manager shall notify the NRC immediately (within 1 hour) after discovery of the theft or loss and ensure that plant management is notified of the event.

FOLLOWUP ACTIONS:

The Manager, Regulatory Affairs shall ensure the written followup report and any subsequent reports are prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 4

TITLE: Incident Involving Byproduct, Source, or Special Nuclear Material

FORMAT: Notification of the NRC Operation Center via the ENS within specified time limits and/or written report within 30 days as specified in the tables provided.

APPLICABILITY: CPNPP is subject to this reporting requirement as delineated below and in Tables NR-4a through NR-4c.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR20.2202(a)

Each licensee shall immediately report any events involving byproduct, source, or special nuclear material possessed by the Licensee that may have caused or threatens to cause:

1) An individual to receive:
   a) TEDE $\geq$ 25 rems
   b) DE $\geq$ 75 rems (eye)
   c) SE $\geq$ 250 rads (skin or extremity)

2) The release of radioactive material in concentrations which, if averaged over a period of 24 hours, would exceed 5 times the occupational annual limit or intake for radioactive material in appendix B, Table 1, Column 2 of 10CFR20; or

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From 10CFR20.2202(b)

Each Licensee shall within 24 hours of discovery of the event, report any event involving licensed material possessed by the Licensee that may have caused or threatens to cause:

1) An individual to receive, in a period of 24 hours:
   a) TEDE $\geq$ 5 rems
   b) DE $\geq$ 15 rems (eye)
   c) SE $\geq$ 50 rems (skin or extremity)

2) The release of radioactive material, inside or outside of a restricted area, so that, had an individual been present for 24 hours, could have received an intake in excess of one occupational annual limit on intake from 10CFR20, appendix B, Table 1, Column 2.

From 10CFR20.2203(a)(1)and(2)

Report in writing within 30 days of occurrence the following types of incidents:

1. Any incident for which notification is required by 10CFR20.2202.

2. Doses in excess of any of the following:

   (i) The occupational dose limits for adults in 10CFR20.1201; or
   (ii) The occupational dose limits for a minor in 10CFR20.1207; or
   (iii) The limits for an embryo/fetus of a declared radiation worker in 10CFR20.1208; or

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(iv) The limits for an individual member of the public in 10CFR20.1301; or
(v) Any applicable limit in the license; or
(vi) The ALARA constrains for air emissions under 10CFR20.1101(d)

3. Levels of radiation or concentrations of radioactive material.

   (i) Restricted area in excess of any applicable limit in the license.
   (ii) An unrestricted area in excess of 10 times any applicable limit set forth in this part or in the license.

4. Radiation levels or releases of radioactive material in access of 40CFR190.

From 10CFR50 Appendix I.IV.A

If the quantity of radioactive material actually released in effluents to unrestricted areas from a light-water-cooled nuclear power reactor during any calendar quarter is such that the resulting radiation exposure, calculated on the same basis as the respective design objective exposure, would exceed one-half the design objective annual exposure derived pursuant to Sections II and III, the licensee shall:

1. Make an investigation to identify the causes for such release rates;

2. Define and initiate a program of corrective action; and

3. Report these actions as specified in 10CFR50.4 [Written Communications] within 30 days from the end of the quarter during which the release occurred.

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From 10CFR140.6(a)

In the event of bodily injury or property damage arising out of or in connection with the possession or use of the radioactive material at the location or in the course of transportation or in the event any claim is made therefore, written notice containing particulars sufficient to identify the licensee and reasonably obtainable information with respect to the time, place and circumstances thereof, or the nature of the claim shall be furnished by or for the licensee to the Director of NRR or Director of Nuclear Material Safety and Safeguards as appropriate, as promptly as practicable.

From 10CFR20.2201(e)

Any report filed with the Commission pursuant to [10CFR20.2201] shall be prepared so that names of individuals who have received exposure to radiation are stated in a separate and detachable part of the report.

From 10CFR20.2203(b)(1)

CONTENT: Each report required under [10CFR20.2203(a)] must describe the extent of exposure of individuals to radiation or to radioactive material, including, as appropriate:

(i) Estimates of each individual's dose; and
(ii) Levels of radiation and concentrations of radioactive material involved; and
(iii) The cause of the elevated exposures, dose rates or concentrations; and
(iv) Corrective steps taken or planned to ensure against a recurrence, including the schedule for achieving conformance with applicable limits, generally applicable environmental standards, and associated license conditions.

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From 10CFR20.2203(b)(2)

Each report filed with the Commission pursuant to [10CFRF20.2203(a)] must include for each individual exposed: the name, social security account number, and date of birth. The report must be prepared so that this information is stated in a separate and detachable part of the report. The separate personal information must be clearly labeled with "Privacy Act Information: Not for Public Disclosure."

From 10CFR20.2203(c)

Occurrences included in 10CFR20.2203(a) must be reported in accordance with procedures described in 10CFR50.73(b), (c), (d), (e) and (g) and must also include the information required in 10CFR20.2203(b). Occurrences reported in accordance with 10CFR50.73 need not be reported by a duplicate report under 10CFR20.2203(a).

ADDITIONAL INFORMATION: The following tables provide a brief summary of the requirements listed above:

Table NR-4a:	Summary of Radiological Exposure Reporting Requirements
Table NR-4b:	Summary of Airborne Intake Reporting Requirements
Table NR-4c:	Summary of Release of Radioactive Material Reporting Requirements
Table NR-4d:	Summary of Miscellaneous Events Involving Licensed Material

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CONTROL ROOM ACTIONS:

The Shift Manager shall notify the NRC of events determined to require 1-hour and 4-hour notification and notify plant management of the event.

The Shift Manager shall notify plant management of the event if a 24-hour notification report may be necessary.

FOLLOWUP ACTIONS:

Plant management shall ensure the NRC is notified of events determined to require 24-hour notification.

The Responsible Manager as assigned in accordance with STA-422, shall ensure the information for the written report is gathered.

The Radiation Protection Manager shall ensure the written report is prepared in accordance with the applicable regulatory and procedural requirements.

The Radiation Protection Manager should ensure that the Risk and Reliability Supervisor is notified at the earliest practical time of any event reportable pursuant to 10CFR140.6(a) to allow participation in report preparation.

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TABLE NR-4a:SUMMARY OF RADIOLOGICAL EXPOSURE REPORTING REQUIREMENTS

CONDITION	EXPOSURE	SOURCE	TYPE OF REPORT
Occupational Dose Limits for Minors	The annual occupational dose limit for minors is 10% of the annual dose limit specified for adult workers in 10CFR20.1201	Requirement: 10CFR20.1207 Report: 10CFR20.2203(a)(2)(ii)	30 day LER (OL)
Individual exposed to licensed material within a restricted area	(1) Annual Limit, whichever is more limiting: 5 rem TEDE or 50 rem CDE (organ or tissue)	Requirement: 10CFR20.1201(a) Report: 10CFR20.2203(a)(2) (i)	30 day LER (OL)
	(2) Annual Limit 15 rem (eye) 50 rem (skin or any one extremity		
	(3) Individual's accumulated occupational dose is documented with licensee		
Any event involving licensed material possessed that may have caused or threatens to cause exposure to individual	$\geq$ 5 rem TEDE $\geq$15 rem (eye) $\geq$50 rem (skin or any one extremity)	Requirement: 10CFR20.2202 Report: 10CFR20.2203	24 hour notification via ENS, AND 30 day LER (OL)
Event involving byproduct, source, or special nuclear material that may have caused or threatens to cause exposure to individual	$\geq$ 25 rem TEDE $\geq$ 75 rem (eye) $\geq$250 rad (skin or any one extremity)	Requirement: 10CFR20.2202 Report: 10CFR20.2203	Immediate notification via ENS, AND 30 day LER (OL)
Limits for members of the public	Annual Limit: 100 mrem TEDE Unrestricted Area Dose: 2 mrem in any one hour	Requirement: 10CFR20.1301 Report: 10CFR20.2203	30 day LER (OL)
Limits for Embryo/Fetus of a declared pregnant radiation worker	Gestation Period Limit: 500 mrem TEDE (with a uniform monthly exposure rate)	Requirement: 10CFR20.1208 Report: 10CFR20.2203	30 day LER (OL)

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TABLE NR-4b: SUMMARY OF AIRBORNE INTAKE REPORTING REQUIREMENTS

CONDITION	INTAKE	SOURCE	TYPE OF REPORT
Individual in a restricted area	INTAKE BY INHALATION. If the only intake of radionuclides is by inhalation, the total effective dose equivalent limit is not exceeded if the sum of the deep-dose equivalent divided by the total effective dose equivalent limit, and the sum of the calculated committed effective dose equivalents to all significantly irradiated organs or tissues (T) calculated from bioassay data using appropriate biological models and expressed as a fraction of the annual limit. INTAKE BY ORAL INGESTION. If the occupationally exposed individual also receives an intake of radionuclides by oral ingestion greater than 10 percent of the applicable oral ALI, the licensee shall account for this intake and include it in demonstrating compliance with the limits. INTAKE THROUGH WOUNDS OR ABSORPTION THROUGH SKIN. The licensee shall evaluate and, to the extent practical, account for intakes through wounds or skin absorption.	Requirement: 10CFR20.1202 Report: 10CFR20.2203	30 day LER (OL)
Individual in a restricted area	In addition to the annual dose limits, the licensee shall limit the soluble uranium intake by an individual to 10 milligrams in a week in consideration of chemical toxicity (see footnote 3 of appendix B to 10CFR20.1001-2401).	Requirement: 10CFR20.1201(e) Report: 10CFR20.2203(a)	30 day LER (OL)
Individual in an unrestricted area	The annual average concentrations of radioactive material released in gaseous and liquid effluents at the boundary of the unrestricted area do not exceed the values specified in 10CFR20, appendix B, Table 2.	Requirement: 10CFR20.1302(b)(2) (i) Report: 10CFR20.2203(a)	30 day LER (OL)

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TABLE NR-4c: SUMMARY OF RELEASE OF RADIOACTIVE MATERIAL REPORTING REQUIREMENTS

CONDITION	INTAKE	SOURCE	TYPE OF REPORT
Airborne release to unrestricted areas.	Airborne release in unrestricted area >20 times 10CFR20 limits in Appendix B, Table 2, Column 1	Requirement: 10CFR50.73(a)(2)(viii)(A) Report: 10CFR50.73(a)(2)(viii)(A)	(OL): 60 day LER
Liquid release to unrestricted areas.	Liquid release, when averaged over 1 hour, exceeds 20 times the concentration in 10CFR20, Appendix B, Table 2, Column 2, at the point of entry into the receiving waters, except tritium and the dissolved noble gases.	Requirement: 10CFR50.73(a)(2)(viii)(B) Report: 10CFR50.73(a)(2)(viii)(B)	(OL): 60 day LER
Event involving licensed material that may have caused or threatens to cause release to unrestricted areas.	Release in concentration which, if averaged over 24 hours, would exceed 5 times the Annual Limit on Intake from 10CFR20, Appendix B, Table 1, Column 2.	Requirement: 10CFR20.2202(a)(2) Report: 10CFR20.2203(a)(i)	(OL): 1 hour notification via ENS; 30 day written report
Event involving licensed material that may have caused or threatens to cause release to unrestricted areas.	Release in concentration which, if averaged over 24 hours, would exceed 1 times the Annual Limit on Intake from 10CFR20, Appendix B, Table 1, Column 2.	Requirement: 10CFR20.2202(b)(2) Report: 10CFR20.2203(a)(c)	(OL): 24 hour notification via ENS; 30 day written report
Unrestricted area.	Levels of radiation or concentrations of radioactive material in an unrestricted area in excess of 10 times the applicable limit in 10CFR20 or in license.	Requirement: 10CFR20.2203(a)(3)(ii) Report: 10CFR20.2203(a)(3)(ii)	(OL): 30 day written report
Radiation doses received by members of the public in the general environment.	Annual dose or dose commitment to member of the public due to releases and radiation from Uranium fuel cycle sources: >25 mrem/year whole body >25 mrem/year any organ >75 mrem/year thyroid or in excess of license conditions to 10CFR190.	Requirement: 40CFR190.10(a) ODCM Control 3.11.4 Action A Report: 10CFR20.2203(a)(4)	30 day written report per ODCM
Radiation doses received by any real individual who is located beyond the controlled area of the ISFSI.	Annual dose or dose commitment to any real individual who is located beyond the controlled area of the ISFSI: >25 mrem/year whole body >25 mrem/year any critical organ >75 mrem/year thyroid as a result of exposure to: (1) Planned discharges of radioactive materials, radon and its decay products excepted, to the general environment, (2) Direct radiation from ISFSI or MRS operations, and (3) Any other radiation from uranium fuel cycle operations within the region. .	Requirement: 72.11(b)	2 working Days

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TABLE NR-4c: SUMMARY OF RELEASE OF RADIOACTIVE MATERIAL REPORTING REQUIREMENTS

CONDITION	INTAKE	SOURCE	TYPE OF REPORT
Radioactive materials entering the general environment from the entire uranium fuel cycle, per gigawatt-year of electrical energy produced by the fuel cycle.	The total quantity contains less than 50,000 curies of krypton-85, 5 millicuries of iodine-129, and 0.5 millicuries combined of plutonium-239 and other alpha-emitting transuranic radionuclides with half-lives greater than one year.	Requirement: 40CFR190.10(b) Report: 10CFR20.2203(a)(4)	30 day written report (after learning of excessive levels) per ODCM
Restricted area.	Restricted area radiation level or concentrations of radioactive material in excess of license limits.	Requirement: 10CFR20.2203(a)(3) (i) Report: 10CFR20.2203(a)(3) (i)	30 day written report
Unrestricted area	Excess of 10 times any applicable limit set forth in 10CFR20 or in the license.	Requirement: 10CFR20.2203(a)(3)(ii) Report: 10CFR20.2203(a)(3)(ii)	30 day written report
Dose or dose commitment to a member of the public in liquid effluents released to unrestricted areas.	Calculated dose is: >1.5 mrem/quarter whole body >5 mrem/quarter any organ >3 mrem/year whole body >10 mrem/year any organ	Requirement: ODCM Control 3.11.1.2 10CFR50, Appendix I.IV.A Report: ODCM Control 3.11.1.2 10CFR50, Appendix I.IV.A	30 day special report
Radioactive material is released to the environment in excess of ODCM effluent release limits and the quantity released in a 24 hour period exceeds the EPA Reportable Quantity (RQ) Air dose due to noble gases released in gaseous effluents at and beyond site boundary	Radioactive material in releases is in excess of ODCM radiological Effluent Control 3/4.11.1.1, 3/4.11.1.2, 3/4.11.2.1, 3/4.11.2.2 and 3/4.11.2.3; and is in excess of the ODCM limits by more than the RQ in a 24 hour period. Calculated air dose: >5 mrads/quarter Gamma >10 mrads/quarter Beta >10 mrads/year Gamma >20 mrads/year Beta	Requirement: 40CFR302 Requirement: ODCM Control 3.11.2.2 Action A 10CFR50 Appendix I.IV.A Report: ODCM Control 3.11.2.2 Action A 10CFR50 Appendix I.IV.A	Immediate telephone notification to the EPA National Response Center (800)424-8802 (primary) or (202)267-2675 (backup) 30 day special report

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TABLE NR-4c: SUMMARY OF RELEASE OF RADIOACTIVE MATERIAL REPORTING REQUIREMENTS

CONDITION	INTAKE	SOURCE	TYPE OF REPORT
Dose to a member of the public from I-131, I-133, tritium, and all radionuclides with half-lives >8 days in gaseous effluents released at and beyond site boundary	Calculated dose released: >7.5 mrem/quarter any organ >15 mrem/year any organ	Requirement: ODCM Control 3.11.2.3 Report: ODCM Control 3.11.2.3 Action A	30 day special report
Radioactive gaseous waste discharged without treatment	Radioactive gaseous waste discharged without treatment; AND >0.2 mrad to air from Gamma >0.4 mrad to air from Beta >0.3 mrem any organ of member of public	Requirement: ODCM Control 3.11.2.4 Report: ODCM Control 3.11.2.4 Action A	30 day special report
Radiological Environmental Monitoring Program results	Plant effluents in an environmental sampling medium exceeds reporting levels of ODCM Table 3.12-2 when averaged over calendar quarter	Requirement: ODCM Table 3.12-1 Report: ODCM Control 3.12.1 Action B	30 day special report
Projected dose due to liquid effluent released to restricted areas	Radioactive liquid waste discharged without treatment; AND projected dose is: >0.06 mrem/31 days whole body, OR >0.2 mrem/31 days any organ; AND any portion of Liquid Radwaste System not in operation	Requirement: ODCM Control 3.11.1.3 Action A Report: ODCM Control 3.11.1.3 Action B	30 day special report

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TABLE NR-4c: SUMMARY OF RELEASE OF RADIOACTIVE MATERIAL REPORTING REQUIREMENTS

Bodily injury or property damage arising out of or in connection with the possession or use of the radioactive material at the location or in transportation or in the event any insurance claim is made.	Requirement: 10CFR140.8(a)	Prompt written notification to the NRC
Submit a 30 day report to the NRC for any water sample result for onsite groundwater that is or may be used as a source of drinking water that exceeds the criteria in the Radiological Environmental Monitoring Program for 30 day reporting of offsite water sample results. Copies of the report will also be provided to the appropriate state agency. The 30-day special report should include: i. A statement that the report is being submitted in support of the GPI, ii. A list of the contaminant(s) and the verified concentration(s)iii. Description of the action(s) taken iv. An estimate of the potential or bounding annual dose to a member of the public, and v. Corrective action(s), if necessary, that will be taken to reduce the projected annual dose to a member of the public to less than the limits in 10CFR50 Appendix I.	Requirement: CDF 27408	30 day special report

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TITLE: Failure to Comply or Existence of a Defect

FORMAT: Initial notification by facsimile or by telephone to the NRC within 2 days following receipt of evaluation results by the responsible corporate officer if evaluation results indicate that the condition could create a substantial safety hazard.

Written report to the NRC within 30 days following receipt of evaluation results by the responsible corporate officer if evaluation results indicate that the condition could create a substantial safety hazard.

If an evaluation of a condition cannot be completed within 60 days from discovery, an interim report shall be submitted within 60 days of the discovery.

If the deviation or failure to comply involves basic components that CPNPP supplied to another entity, and CPNPP does not have the capability to perform the evaluation to determine if a defect exists, then CPNPP shall notify the purchasers within 5 working days of this determination.

APPLICABILITY: CPNPP is subject to this reporting requirement as delineated in the “REQUIREMENT” and “ADDITIONAL INFORMATION” sections.

DEFINITIONS: Basic component - A structure, system, or component, or part thereof that affects its safety function necessary to assure: (A) The integrity of the reactor coolant pressure boundary; (B) The capability to shut down the reactor and maintain it in a safe shutdown condition; or (C) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10CFR50.34(a)(1), 10CFR50.67(b)(2), or 10CFR100.11. Basic components are items designed and manufactured under a quality assurance program complying with appendix B to part 50 of this chapter, or commercial grade items which have successfully completed the dedication process. Basic component includes safety-related design, analysis, inspection, testing, fabrication, replacement of parts, or consulting services that are associated with the component hardware, design certification, design approval, or information in support of an early site permit application under part 52 of this chapter, whether these services are performed by the component supplier or others.

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Commercial grade item - A structure, system, or component, or part thereof that affects its safety function, that was not designed and manufactured as a basic component. Commercial grade items do not include items where the design and manufacturing process require in-process inspections and verifications to ensure that defects or failures to comply are identified and corrected (i.e., one or more critical characteristics of the item cannot be verified).

Commission - The Nuclear Regulatory Commission or its duly authorized representatives.

Constructing or construction - The analysis, design, manufacture, fabrication, placement, erection, installation, modification, inspection, or testing of a facility or activity which is subject to the regulations in this part and consulting services related to the facility or activity that are safety related.

Critical characteristics - Critical characteristics are those important design, material, and performance characteristics of a commercial grade item that, once verified, will provide reasonable assurance that the item will perform its intended safety function.

Dedicating entity - The organization that performs the dedication process. Dedication may be performed by the manufacturer of the item, a third-party dedicating entity, or the licensee itself. The dedicating entity, pursuant to 10CFR21.21(c) of this part, is responsible for identifying and evaluating deviations, reporting defects and failures to comply for the dedicated item, and maintaining auditable records of the dedication process.

Dedication - An acceptance process undertaken to provide reasonable assurance that a commercial grade item to be used as a basic component will perform its intended safety function and, in this respect, is deemed equivalent to an item designed and manufactured under a 10CFR Part 50, App. B, quality assurance program. This assurance is achieved by identifying the critical characteristics of the item and verifying their acceptability by inspections, tests, or analyses performed by the purchaser or third-party dedicating entity after delivery, supplemented as necessary by one or more of the following: commercial grade surveys; product inspections or witness at hold points at the manufacturer's facility, and analysis of historical records for acceptable performance. In all cases, the dedication process must be conducted in accordance with the applicable provisions of 10CFR Part

50, App. B. The process is considered complete when the item is designated for use as a basic component.

Defect - A deviation in a basic component delivered to a purchaser for use in a facility or an activity subject to the regulations in this part if, on the basis of an evaluation, the deviation could create a substantial safety hazard; or the installation, use, or operation of a basic component containing a defect as defined in this section; or a deviation in a portion of a facility subject to the early site permit, standard design certification, standard design approval, construction permit, combined license or manufacturing licensing requirements of part 50 or part 52 of this chapter, provided the deviation could, on the basis of an valuation, create a substantial safety hazard and the portion of the facility containing the deviation has been offered to the purchaser for acceptance; or a condition or circumstance involving a basic component that could contribute to the exceeding of a safety limit, as defined in the technical specifications of a license for operation issued under part 50 or part 52 of this chapter; or an error, omission or other circumstance in a design certification, or standard design approval that, on the basis of an evaluation, could create a substantial safety hazard.

Deviation - A departure from the technical requirements included in a procurement document, or specified in early site permit information, a standard design certification or standard design approval.

Director - An individual, appointed or elected according to law, who is authorized to manage and direct the affairs of a corporation, partnership or other entity. In the case of an individual proprietorship, director means the individual.

Discovery - The completion of the documentation first identifying the existence of a deviation or failure to comply potentially associated with a substantial safety hazard within the evaluation procedures discussed in 10CFR21.21(a).

Evaluation - The process of determining whether a particular deviation could create a substantial hazard or determining whether a failure to comply is associated with a substantial safety hazard.

Notification - Telephonic communication to the NRC Operations Center or written transmittal of information to the NRC Document Control Desk.

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Operating or operation - The operation of a facility or the conduct of a licensed activity which is subject to the regulations in this part and consulting services related to operations that are safety related.

Procurement document - A contract that defines the requirements which facilities or basic components must meet in order to be considered acceptable by the purchaser.

Responsible officer - The president, vice-president or other individual in the organization of a corporation, partnership, or other entity who is vested with executive authority over activities subject to this part. At CPNPP the Site Vice President is the Responsible Officer.

Substantial safety hazard - A loss of safety function to the extent that there is a major reduction in the degree of protection provided to public health and safety for any facility or activity licensed or otherwise approved or regulated by the NRC, other than for export, under parts 30, 40, 50, 52, 60, 61, 63, 70, 71, or 72 of this chapter.

Supplying or supplies - Contractually responsible for a basic component used or to be used in a facility or activity which is subject to the regulations in this part.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR21.21

(a)(1) Each individual, corporation, partnership, dedicating entity, or other entity subject to the regulations in this part shall adopt appropriate procedures to evaluate deviations and failures to comply to identify defects and failures to comply associated with substantial safety hazards as soon as practicable, and, except as provided in paragraph (a)(2) of this section, in all cases within 60 days of discovery, in order to identify a reportable defect or failure to comply that could create a substantial safety hazard, were it to remain uncorrected.

(a)(2) Ensure that if an evaluation of an identified deviation or failure to comply potentially associated with a substantial safety hazard cannot be completed within 60 days from discovery of the deviation or failure to comply, an interim report is prepared and submitted to the Commission through a director or responsible officer or designated

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person as discussed in 10CFR21.21(d)(5). The interim report should describe the deviation or failure to comply that is being evaluated and should also state when the evaluation will be completed. This interim report must be submitted in writing within 60 days of discovery of the deviation or failure to comply.

(a)(3) Ensure that a director or responsible officer subject to the regulations of this part is informed as soon as practicable, and, in all cases, within the 5 working days after completion of the evaluation described in paragraphs (a)(1) or (a)(2) of this section if the manufacture, construction, or operation of a facility or activity, a basic component supplied for such facility or activity, or the design certification or design approval under part 52 of this chapter fails to comply with the Atomic Energy Act of 1954, as amended, or any applicable rule, regulation, order, or license of the Commission or standard design approval under part 52 of this chapter, relating to a substantial safety hazard, or contains a defect.

(b) If the deviation or failure to comply is discovered by a supplier of basic components, or services associated with basic components, and the supplier determines that it does not have the capability to perform the evaluation to determine if a defect exists, then the supplier must inform the purchasers or affected licensees within five working days of this determination so that the purchasers or affected licensees may evaluate the deviation or failure to comply, pursuant to 10CFR21.21(a).

(c)(1) A dedicating entity is responsible for identifying and evaluating deviations and reporting defects and failures to comply associated with substantial safety hazards for dedicated items; and maintaining auditable records for the dedication process.

(d)(1) A director or responsible officer subject to the regulations of this part or a person designated under 10CFR21.21(d)(5) must notify the Commission when he or she obtains information reasonably indicating a failure to comply or a defect affecting the manufacture, construction or operation of a facility or an activity within the United States that is subject to the licensing requirements under parts 30, 40, 50, 52, 60, 61, 63, 70, 71, or 72 of this chapter and that is within his or her organization's responsibility; or a basic component that is within his or her organization's responsibility and is supplied for a facility or an activity within the United States that is subject to the licensing, design certification, or approval requirements under parts 30, 40, 50, 52, 60, 61, 63, 70, 71, or 72 of this chapter.

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(d)(2) The notification to NRC of a failure to comply or of a defect under paragraph (d)(1) of this section and the evaluation of a failure to comply or a defect under paragraphs (a)(1) and (a)(2) of this section, are not required if the director or responsible officer has actual knowledge that the Commission has been notified in writing of the defect or the failure to comply.

(d)(3) Notification required by paragraph (d)(1) of this section must be made as follows: Initial notification by facsimile, which is the preferred method of notification, to the NRC Operations Center at (301) 816 - 5151 or by telephone at (301) 816 - 5100 within two days following receipt of information by the director or responsible corporate officer under paragraph (a)(1) of this section, on the identification of a defect or a failure to comply. Verification that the facsimile has been received should be made by calling the NRC Operations Center. This paragraph does not apply to interim reports described in 10CFR21.21(a)(2). Written notification to the NRC at the address specified in 10CFR21.5 within 30 days following receipt of information by the director or responsible corporate officer under paragraph (a)(3) of this section, on the identification of a defect or a failure to comply.

(d)(5) The director or responsible officer may authorize an individual to provide the notification required by this paragraph, provided that, this shall not relieve the director or responsible officer of his or her responsibility under this paragraph.

(e) Individuals subject to this part may be required by the Commission to supply additional information related to a defect or failure to comply. Commission action to obtain additional information may be based on reports of defects from other reporting entities.

CONTENT: From 10CFR21.21(d)(4)

The written report required by this paragraph shall include, but need not be limited to, the following information, to the extent known:

(i) Name and address of the individual or individuals informing the Commission.

(ii) Identification of the facility, the activity, or the basic component supplied for such facility or such activity within the United States which fails to comply or contains a defect.

(iii) Identification of the firm constructing the facility or supplying the basic component which fails to comply or contains a defect.

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(iv) Nature of the defect or failure to comply and the safety hazard which is created or could be created by such defect or failure to comply.

(v) The date on which the information of such defect or failure to comply was obtained.

(vi) In the case of a basic component which contains a defect or fails to comply, the number and location of these components in use at, supplied for, being supplied for, or may be supplied for, manufactured, or being manufactured for one or more facilities or activities subject to the regulations in this part.

(vii) The corrective action which has been, is being, or will be taken; the name of the individual or organization responsible for the action; and the length of time that has been or will be taken to complete the action.

(viii) Any advice related to the defect or failure to comply about the facility, activity, or basic component that has been, is being, or will be given to purchasers or licensees.

ADDITIONAL INFORMATION:

From NUREG 1022, Rev 2: 10 CFR Part 21, "Reporting of Defects and Noncompliance," as amended during 1991, encourages licensees of operating nuclear power plants to reduce duplicate evaluation and reporting effort by evaluating deviations in basic components under the 10 CFR 50.72, 50.73, and 73.71 reporting criteria. As indicated in 10 CFR 21.2(c) "For persons licensed to operate a nuclear power plant under Part 50 of this chapter, evaluation of potential defects and appropriate reporting of defects under 10 CFR 50.72, 50.73. or 73.71 of this chapter satisfies each person's evaluation, notification, and reporting obligation to report defects under this part ...." As discussed in the Statement of Considerations for 10 CFR 21 (56 FR 36081, July 31, 1991), the only case where a defect in a basic component of an operating reactor might be reportable under Part 21, but not under 10 CFR 50.72, 50.73, or 73.71 would involve Part(s) on the shelf. This type of defect, if it does not represent a condition reportable under 10 CFR 50.72 or 50.73, might still represent a condition reportable under 10 CFR Part 21. For an LER, if the defect meets one of the criteria of 10 CFR 50.73, check the applicable paragraph in Item 11 of NRC Form 366 (LER Form). Licensees are also encouraged to check the "Other" block and indicate "Part 21" in the space immediately below if the defect in a basic component could create a substantial safety hazard. The wording in Item 16 ("Abstract") and Item 17 ("Text") should state that the report constitutes a Part 21 notification. If the defect is applicable to other facilities at a multi-unit site, a single LER may be used by indicating the other involved facilities in Item 8 on the LER Form.

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CONTROL ROOM ACTIONS: None

LUMINANT POWER GUIDANCE

To eliminate possible confusion and dual evaluation of events/conditions at Comanche Peak Nuclear Power Plant (CPNPP), the following guidance is being provided to describe the relationship between 10CFR50.72 and 10CFR50.73 and 10CFR21.

The criterion for reporting a defect under 10CFR21 (part 21) for nuclear reactors is that a deviation in a basic component under reasonably expected operational circumstances, including expected normal operation, transients, and design basis accidents, could create a substantial safety hazard. Basic components are plant structures, systems, or components necessary to ensure the (i) integrity of the reactor coolant boundary; (ii) capability to shut down the reactor and keep it in a safe condition; or (iii) prevent or mitigate the consequences of an accident which could result in potential offsite exposures comparable to those referred to in 10CFR100.11.

At CPNPP events or conditions are reported under 10CFR50.72 and 50.73. Basic components or services associated with basic components which are installed in the plant which have deviations and, thus, could be potential defects (i.e., could create substantial safety hazards), should be evaluated under the appropriate criteria of 10CFR50.72 and 50.73 to determine if the deviations are a reportable event or condition. That is, where deviations in basic components do produce potentially reportable events or conditions, the deviations should be evaluated under the criteria of 10CFR50.72 and 50.73. Several paragraphs of 10CFR50.72 and 50.73 contain criteria on reporting of possible defects and are comparable to the criteria of part 21 (e.g., 10CFR50.72(b)(1)(ii) or 10CFR50.73(a)(2)(ii); 10CFR50.72(b)(2)(iii) or 10CFR50.73(a)(2)(v) etc.). If the evaluation of the event/condition using the criteria of 10CFR50.72 or 10CFR50.73 results in a finding that the event is reportable and the event is reported via these sections, then as indicated in 10CFR21.2(c), the evaluation, notification, record keeping, and reporting obligation of part 21 are met. If the event is determined not to be reportable, the obligations of part 21 are met by the evaluation.

However, one category of defects which shall still be reportable under part 21 rather than 10CFR50,72 or 50.73 are those defects discovered at CPNPP in equipment which have never been installed or used in the nuclear plant.

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Defects in these basic components cannot create situations which are reportable under 10CFR50.72 or 50.73 since these components cannot create a reportable event or condition. Basic components which are "delivered and accepted" by CPNPP but are "not installed" in the plant should be evaluated under part 21 and reported under part 21 if found to be reportable. It should be noted that deviations or potential defects discovered during receipt inspection are not reportable by CPNPP if CPNPP returns the basic component to the vendor for evaluation. If CPNPP chooses to keep the basic component because of unavailability of another component, or for whatever reason, then CPNPP should evaluate the potential defects under part 21. (Reference 56 FR 36081, July 31, 1991.)

ADDITIONAL RESPONSIBILITIES: The identifying organization shall ensure that any potentially reportable condition is documented in accordance with STA-421. If purchaser of basic components is required to be notified per 10CFR21.21(b), the notification shall be by TXX letter.

From 10CFR21.21(a)(3)

The Manager, Regulatory Affairs is responsible for ensuring that director or responsible officer subject to the regulations of this part is informed as soon as practicable, within 5 working days of the completion of the evaluation described by 10CFR21.21(a)(1 or 2).

FOLLOWUP ACTIONS: The Manager, Regulatory Affairs is responsible for determining reportability pursuant to 10CFR21 and ensuring interim, initial, and followup reports are prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 6

TITLE: Fitness-for-Duty Events

FORMAT: Notification via telephone within 24 hours of discovery.

Note that a list of the events reported under 10CFR26 shall be included in the Fitness-for-Duty (FFD) Annual Program Performance Report required per 10CFR26.177.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR26.719

(a) Required reports. Each licensee and entity who is subject to this subpart shall inform the NRC of significant violations of the FFD policy, significant FFD program failures, and errors in drug and alcohol testing. These events must be reported under this section, rather than under the provisions of 10CFR 73.71.

(b) Significant FFD policy violations or programmatic failures. The following must be reported to the NRC Operations Center by telephone within 24 hours after the licensee discovers the violation:

  (1) The use, sale, distribution, possession, or presence of illegal drugs, or the consumption or presence of alcohol within a protected area;

  (2) Any acts by any person licensed under 10CFR parts 52 and/or 55 to operate a power reactor, FFD program personnel, or any supervisory personnel who are authorized under this part, if such acts——

    (i) Involve the use, sale, or possession of a controlled substance;

    (ii) Result in a determination that the individual has violated the licensee's FFD policy (including subversion); or

    (iii) Involve the consumption of alcohol within a protected area or while performing the duties that require the individual to be subject to the FFD program;

  (3) Any intentional act that casts doubt on the integrity of the FFD program; and

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(4) Any programmatic failure, degradation, or discovered vulnerability of the FFD program that may permit undetected drug or alcohol use or abuse by individuals within a protected area, or by individuals who are assigned to perform duties that require them to be subject to the FFD program.

(c) Drug and alcohol testing errors.

(1) Within 30 days of completing an investigation of any testing errors or unsatisfactory performance discovered in performance testing at either a licensee testing facility or an HHS-certified laboratory, in the testing of quality control or actual specimens, or through the processing of reviews under 10CFR26.39 and MRO reviews under 10CFR26.185, as well as any other errors or matters that could adversely reflect on the integrity of the random selection or testing process, the licensee or other entity shall submit to the NRC a report of the incident and corrective actions taken or planned. If the error involves an HHS-certified laboratory, the NRC shall ensure that HHS is notified of the finding.

(2) If a false positive error occurs on a blind performance test sample submitted to an HHS-certified laboratory, the licensee or other entity shall notify the NRC within 24 hours after discovery of the error.

(3) If a false negative error occurs on a quality assurance check of validity screening tests, as required in 10CFR26.137(b), the licensee or other entity shall notify the NRC within 24 hours after discovery of the error.

(d) Indicators of programmatic weaknesses. Licensees and other entities shall document, trend, and correct non-reportable indicators of FFD programmatic weaknesses under the licensee"s or other entity"s corrective action program, but may not track or trend drug and alcohol test results in a manner that would permit the identification of any individuals.

CONTENT: As requested during the notification.

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ADDITIONAL INFORMATION:	A Condition Report is not required to document FFD events. Refer to STA-910, "Fitness-for-Duty Program," for additional information. Plant Security notifies the Duty Manager of positive test results.
CONTROL ROOM ACTIONS:	None
ACTIONS:	The Duty Manager shall ensure that any required notification is made within 24 hours. Notification of individual's supervision by the Duty Manager is in accordance with STA-910 for positive test concerns. The Duty Manager shall forward the following documentation to the CPNPP Security Manager upon completion of notifications: (1) Reportability determination and subsequent notifications for positive test results or other potentially significant or significant fitness for duty events; and (2) documentation of immediate corrective actions taken (e.g., deactivation of individual's badge). Fitness-for-Duty events shall be reported under 10CFR26 rather than 10CFR73.71. The Security Manager is responsible for 10CFR26.719 reporting requirements.

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NONROUTINE REPORT - 7

TITLE: NRC Employee Demonstrating Outward Signs of Impairment

FORMAT: Immediate notification to the Region IV Administrator by telephone. During other than normal working hours, notification via the ENS.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR26.77(c)

If a licensee has a reasonable belief that an NRC employee may be under the influence of any substance, or otherwise unfit for duty, the licensee may not deny access but shall escort the individual. In any instance of this occurrence, the appropriate Regional Administrator must be notified immediately by telephone. During other than normal working hours, the NRC Operations Center must be notified.

CONTENT: As requested during notification.

ADDITIONAL INFORMATION: Refer to STA-910, "Fitness-for-Duty Program," for additional information.

CONTROL ROOM ACTIONS: None

ADDITIONAL RESPONSIBILITIES: Plant management shall ensure an escort is provided for the NRC employee and ensure that the required notification is made.

The Shift Manager or the Duty Manager should ensure Security is appraised of the details of the report in a timely manner.

FOLLOWUP ACTIONS: None

ATTACHMENT 8.D/8
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NONROUTINE REPORT - 8

TITLE:	Information with Significant Implication for Public Health and Safety or Common Defense and Security.
FORMAT:	Notification to NRC Region IV within two (2) working days of identifying the information.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	This is a paraphrased summary only. Refer to source documents listed in Attachment 8.B. From 10CFR30.9(b); 10CFR50.9(b); 10CFR70.9(b); and 10CFR71.7(b) Each applicant or licensee shall notify the Commission of information identified by the applicant or licensee as having for the regulated activity a significant implication for public health and safety or common defense and security. An applicant or licensee violates this paragraph only if the applicant or licensee fails to notify the Commission of information that the applicant or licensee has identified as having a significant implication for public health and safety or common defense and security. Notification shall be provided to the Administrator of the appropriate Regional Office within two working days of identifying the information. This requirement is not applicable to information which is already required to be provided to the Commission by other reporting or updating requirements.
CONTENT:	Information as requested during the notification.

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NONROUTINE REPORT - 8

ADDITIONAL INFORMATION:	None
CONTROL ROOM ACTIONS:	The Shift Manager shall ensure that plant management is notified of the information.
ADDITIONAL RESPONSIBILITIES:	Plant Management shall ensure that the required notification is made to the NRC.
FOLLOWUP ACTIONS:	None

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NONROUTINE REPORT - 9

TITLE: Source Leakage Report and Failure/Damage to Shielding/On-Off Mechanism/Indicator

FORMAT: Written report (timing specified below)

APPLICABILITY: CPNPP is subject to the annual reporting requirement of ODCM Surveillance Requirement 4.7.15.3.

CPNPP is subject to 10CFR31.5.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From ODCM 4.7.15.3

A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microcuries of removable contamination.

From 10CFR31.5(c)(5)

Upon the occurrence of a failure of or damage to, or any indication of a possible failure of or damage to the shielding of the radioactive material or the on-off mechanism or indicator or upon the detection of 0.005 microcuries or more removable radioactive material, shall immediately suspend operation of the device until it has been repaired ... and, within 30 days, furnish to the [NRC Regional office] a report containing a brief description of the event and the remedial action taken.

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NONROUTINE REPORT - 9

CONTENT: From 10CFR31.5(c)(5)

…a brief description of the event and the remedial action taken ....

ADDITIONAL INFORMATION: None

CONTROL ROOM ACTIONS: None

Followup ACTIONS: The Radiation Protection Manager shall ensure the written reports are prepared in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 10

TITLE: Significant change or error in an evaluation model.

FORMAT: Written report to be submitted to the NRC within 30 days of discovery.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR50.46(a)(3)(ii)

For each change to or error discovered in an acceptable evaluation model or in the application of such a model that affects the temperature calculation, the applicant or licensee shall report the nature of the change or error and its estimated effect on the limiting ECCS analysis to the Commission at least annually as specified in 10CFR50.4. If the change or error is significant, the applicant or licensee shall provide this report within 30 days and include with the report a proposed schedule for providing a reanalysis or taking other action as may be needed to show compliance with 10CFR50.46 requirements.

Any change or error correction that results in a calculated ECCS performance that does not conform to the criteria set forth in Paragraph (b) of this section [peak cladding temperature] is a reportable event as described in 10CFR50.55(e), 50.72 and 50.73. The affected applicant or licensee shall propose immediate steps to demonstrate compliance or bring plant design or operation into compliance with 10CFR50.46 requirements.

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NONROUTINE REPORT - 10

ADDITIONAL INFORMATION: From 10CFR50.46(a)(3)(i)

... a significant change or error is one which results in a calculated peak fuel cladding temperature different by more than 50°F from the temperature calculated for the limiting transient using the last acceptable model, or is an accumulation of changes and errors such that the sum of the absolute magnitudes of the respective temperature changes is greater than 50°F.

CONTROL ROOM ACTIONS: The Shift Manager shall notify the NRC of any of the events listed in the "10CFR50.72 and 10CFR50.73 Matrix" (NR-13) within the time limits specified.

FOLLOWUP ACTIONS: The Manager, Regulatory Affairs shall ensure that any required LER is prepared and submitted in accordance with applicable regulatory and procedural requirements.

ATTACHMENT 8.D/11
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NONROUTINE REPORT - 11

TITLE: Closeout or Reduction of Emergency Classification and Preparation of Cleanup.

FORMAT: Notification by verbal summary to offsite authorities followed by written notifications.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From Emergency Plan - Closeout

Verbal notification followed by written summary to offsite agencies within 8 hours of closeout or class reduction from Alert, Site Area and General Emergency. Verbal notification followed by written summary within 24 hours of closeout from Notification of Unusual Event.

From 10CFR50.54(w)(4)(ii) - Cleanup

The licensee shall inform the Director of the Office of Nuclear Reactor Regulation in writing when the reactor is and can be maintained in a safe and stable condition so as to prevent any significant risk to the public health and safety. Within 30 days after the licensee informs the Director that the reactor is in this condition, or at such earlier time as the licensee may elect or the Director may for good cause direct, the licensee shall prepare and submit a cleanup plan for the Director's approval.

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NONROUTINE REPORT - 11

CONTENT: From 10CFR50.54(w)(4)(ii) - Cleanup

The cleanup plan must identify and contain an estimate of the cost of each cleanup operation that will be required to decontaminate the reactor sufficiently to permit the licensee either to resume operation of the reactor or to apply to the Commission under [10CFR] 50.82 for authority to decommission the reactor and to surrender the license voluntarily.

From Emergency Plan - Closeout

The Notification Message Form (EPP-203-8) used to close out the emergency, may be used to satisfy the requirements of verbal notification and written summary to offsite agencies.

ADDITIONAL INFORMATION: Refer to CPNPP Emergency Plan and Procedure EPP-121, "Reentry, Recovery, and Closeout." A Condition Report is not required to document “Closeout or Reduction of Emergency Classification and Preparation of Cleanup” events.

CONTROL ROOM ACTIONS: NONE

FOLLOW UP ACTIONS: The Manager, Regulatory Affairs shall ensure the required written reports are submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 12

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ATTACHMENT 8.D/13
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NONROUTINE REPORT - 13

TITLE: Emergency, Non-Emergency and Licensee Event Reporting

FORMAT: Notification of the NRC Operation Center via the Emergency Notification System (ENS).

Licensee Event Reports prepared on NRC Form 366 and submitted within 60 days of discovery of a reportable event.

APPLICABILITY: CPNPP is subject to these notifications and reporting requirements.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR50 App E IV.D.3

A licensee shall have the capability to notify responsible State and local governmental agencies within 15 minutes after declaring an emergency. The licensee shall demonstrate that the State/local officials have the capability to make a public notification decision promptly on being informed by the licensee of an emergency condition.

From 10CFR50.72

Each nuclear power reactor licensee ... shall notify the NRC Operations Center via the Emergency Notification System of: [any of the events listed in the 10CFR50.72 and 10CFR50.73 Matrix within the time limits specified].

From 10CFR50.73

The holder of an operating license for a nuclear power plant (Licensee) shall submit a Licensee Event Report (LER) for any event of the type described in [the 10CFR50.72 and 10CFR50.73 Matrix] within 60 days after the discovery of the event.

From 10CFR72.75(a)

Each licensee shall notify the NRC Headquarters Operations Center upon the declaration of an emergency as specified in the licensee's approved emergency plan. The licensee shall notify the NRC immediately after notification of the appropriate state or local agencies, but not later than one hour after the time the licensee declares an emergency.

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From FSAR 17.2

17.2.1.6.1 The following actions shall be taken for REPORTABLE EVENTS:

Each REPORTABLE EVENT shall be reviewed by the SORC and the results of this review shall be submitted to the ORC and the Senior Vice President & Chief Nuclear Officer.

From NUREG 0694

Assure that any failure of a PORV or safety valve will be reported to the NRC promptly.

NOTE: This notification occurs during notification of declaration of emergency class in accordance with EPP-201, 10CFR50.72, and 10CFR72.75(a).

CONTENT: Emergency Notification Reports: Content as specified in the CPNPP Emergency Plan Implementing Procedures.

Non-Emergency Event Reports: Content as requested during notification.

LERs: Refer to 10CFR50.73(b) for the required content of the LER.

ADDITIONAL INFORMATION: The LER shall be prepared and submitted in accordance with the guidance found in NUREG-1022. The LER form (NRC Form 366) is available from the NRC's website (www.nrc.gov).

The Public Information Section of Community Relations should notify the Shift Manager of plans for news releases relating to events possibly affecting the health and safety of the public or plant employees or events expected to receive media interest for potential reportability considerations.

Restart of plant after Operating Basis Earthquake is exceeded requires prior to NRC approval per 10CFR100 Appendix A.V.

With the exception of "Events or Conditions that Could Have Prevented Fulfillment of a Safety Function," notifications under 10 CFR 50.72, "Immediate Notification Requirements for Operating Nuclear Power Reactors," are required for any event that occurred within 3 years of the date of discovery, even if the event was not ongoing at the time of discovery.

CONTROL ROOM ACTIONS:

Non-emergency: the Shift Manager shall notify the NRC within the specified time limits after the event and ensure that plant management is notified of the event.

Emergency: perform notifications in accordance with the CPNPP Emergency Plan.

FOLLOWUP ACTIONS:

Non-emergency: The Manager, Regulatory Affairs shall ensure that an LER is prepared and submitted in accordance with the applicable regulatory and procedural requirements, and that a supplement to the LER is prepared and submitted if additional information is requested by the NRC.

Emergency: Followup actions when an emergency action level has been declared is specified in the CPNPP Emergency Plan.

The Emergency Coordinator (or Recovery Manager) shall ensure that all notifications made in accordance with EPP-203 are documented and included in the Plant Incident package.

For emergency class declarations involving the ISFSI, the following follow-up notifications are required in accordance with 10 CFR 72.75(f):

1. Immediately report any further degradation in the level of safety of the ISFSI or other worsening conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made; or any change from one Emergency Class to another; or a termination of the Emergency Class.

2. Immediately report the results of ensuing evaluations or assessments of ISFSI conditions; the effectiveness of response or protective measures taken; and information related to ISFSI behavior that is not understood.

3. Maintain an open, continuous communication channel with the NRC Headquarters Operations Center upon request by the NRC.

ADDITIONAL RESPONSIBILITIES:

From FSAR 17.2.1.1.2.1.1

The SORC shall be responsible for:

h. Review of all events submitted pursuant to 10CFR50.73.

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10CFR50.72 and 10CFR50.73 MATRIX

10CFR50.72	hrs	10CFR50.73	LER
(a)(1)(i) The declaration of any of the Emergency Classes specified in the Emergency Plan: (after notification of state and local agencies).	Less than an hour	*There is no requirement in 10CFR50.73 to report the declaration of an Emergency Class. However, an event or condition that leads to declaration of an Emergency Class may meet one or more of the specific reporting requirements that are in 10CFR50.73*	
(a)(1)(ii) Those non-emergency events specified in paragraph (b) of this section that occurred within three years of the date of discovery.		*There is usually a parallel reporting requirement in 10CFR50.73 that captures a non-emergency event that is reportable under 10CFR50.72. Exceptions are: a press release; notification to another government agency; transport of a contaminated person offsite; and loss of emergency preparedness capability.*	
(a)(2) If the Emergency Notification System is inoperative, the licensee shall make the required notifications via commercial telephone service, other dedicated telephone system, or any other method which will ensure that a report is made as soon as practical to the NRC Operations Center		There is no corresponding requirement in 10CFR50.73	
(a)(3) The licensee shall notify the NRC immediately after notification of the appropriate State or local agencies and not later than one hour after the time the licensee declares one of the Emergency Classes.		*There is usually a parallel reporting requirement in 10CFR50.73 that captures a non-emergency event that is reportable under 10CFR50.72. Exceptions are: a press release; notification to another government agency; transport of a contaminated person offsite; and loss of emergency preparedness capability.*	
(a)(4) The licensee shall activate the Emergency Response Data System (ERDS) as soon as possible but not later than one hour after declaring an Emergency Class of alert, site area emergency, or general emergency. The ERDS may also be activated by the licensee during emergency drills or exercises if the licensee's computer system has the capability to transmit the exercise data.		*There is usually a parallel reporting requirement in 10CFR50.73 that captures a non-emergency event that is reportable under 10CFR50.72. Exceptions are: a press release; notification to another government agency; transport of a contaminated person offsite; and loss of emergency preparedness capability.*	
(b)(1) Any deviation from the plant's Technical Specifications authorized pursuant to 10CFR50.54(x).	1	**(a)(2)(i)(C)** Any deviation from the plant's Technical Specifications authorized pursuant to 10CFR50.54(x).	60 day LER

10CFR50.72 and 10CFR50.73 MATRIX

10CFR50.72	hrs	10CFR50.73	LER
(b)(2)(i) shutdown required by the The initiation of any nuclear plant plant's Technical Specifications [Note: To Mode 3]	4	**(a)(2)(i)(A)** The completion of any nuclear plant shutdown required by the plant's Technical Specifications	60 day LER
There is no corresponding requirement in 10CFR50.72.		**(a)(2)(i)(B)** Any operation or condition which was prohibited by the plant's Technical Specifications except when: [1] (1) The Technical Specification is administrative in nature; (2) The event consisted solely of a case of a late surveillance test where the oversight was corrected, the test was performed, and the equipment was found to be capable of performing its specified safety functions; or (3) The Technical Specification was revised prior to discovery of the event such that the operation or condition was no longer prohibited at the time of discovery of the event.	60 day LER
(b)(2)(iv) (A) Any event that results or should have resulted in emergency core cooling system (ECCS) discharge into the reactor coolant system as a result of a valid signal except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation. (B) Any event or condition that results in actuation of the reactor protection system (RPS) when the reactor is critical except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation.	4	Refer to **(a)(2)(iv)**(A) and (B)	
(b)(2)(xi) Any event or situation, related to the health and safety of the public or on-site personnel, or protection of the environment, for which a news release is planned or notification to other government agencies has been or will be made. Such an event may include an on-site fatality or inadvertent release of radioactively contaminated materials. If not reported under 10CFR50.72(a) or(b)(1) than report it within 4 hours	4*	*There is no corresponding requirement in 10CFR50.73.*	

[1] An "Operation or Condition Prohibited by Technical Specifications" exists when the total allowed restoration and shutdown outage times are exceeded (regardless of time of discovery). Exceeding only the restoration times would not constitute a report under this criterion. Entry into LCO 3.0.3 does not constitute an "Operation or Condition Prohibited by Technical Specifications" unless associated shutdown completion times are exceeded.

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10CFR50.72 and 10CFR50.73 MATRIX

10CFR50.72	hrs	10CFR50.73	LER
(b)(3)(ii) Any event or condition that results in: (A) The condition of the nuclear power plant, including its principal safety barriers, being seriously degraded; or (B) The nuclear power plant being in an unanalyzed condition that significantly degrades plant safety.	8	**(a)(2)(ii)** Any event or condition that resulted in: (A) The condition of the nuclear power plant, including its principal safety barriers, being seriously degraded; (B) The nuclear power plant being in an unanalyzed condition that significantly degraded plant safety.	60 day LER
Refer to plants Emergency Plan regarding declaration of an emergency class		**(a)(2)(iii)** Any natural phenomenon or other external condition that posed an actual threat to the safety of the nuclear power plant or significantly hampered site personnel in the performance of duties necessary for the safe operation of the nuclear power plant.	60 day LER

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10CFR50.72 and 10CFR50.73 MATRIX

10CFR50.72	hrs	10CFR50.73	LER
(b)(3)(iv) (A) Any event or condition that results in valid actuation of any of the systems listed in paragraph 50.73(a)(2)(iv)(B) of this section except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation.	8	**(a)(2)(iv)** (A) Any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B) of this section, except when: *(1)* The actuation resulted from and was part of a pre-planned sequence during testing or reactor operation; or *(2)* The actuation was invalid and; (i) Occurred while the system was properly removed from service; or (ii) Occurred after the safety function had been already completed	60 Day LER
	8	**(a)(2)(iv)** (B) The systems to which the requirements of paragraph (a)(2)(iv)(A) of this section apply are: *(1)* Reactor protection system (RPS) including: reactor scram or reactor trip. *(2)* General containment isolation signals affecting containment isolation valves in more than one system or multiple main steam isolation valves (MSIVs). *(3)* Emergency core cooling systems (ECCS) for pressurized water reactors (PWRs) including: high head, intermediate head, and low head injection systems and the low pressure injection function of residual (decay) heat removal systems. *(4)* ECCS for boiling water reactors (BWRs) including: high pressure and low pressure core spray systems; high pressure coolant injection system; low pressure injection function of the residual heat removal system. *(5)* BWR reactor core isolation cooling system; isolation condenser system; and feedwater coolant injection system. *(6)* PWR auxiliary or emergency feedwater system. *(7)* Containment heat removal and depressurization systems, including containment spray and fan cooler systems. *(8)* Emergency ac electrical power systems, including: emergency diesel generators (EDGs); hydroelectric facilities used in lieu of EDGs at the Oconee Station; and BWR dedicated Division 3 EDGs. *(9)* Emergency service water systems that do not normally run and that serve as ultimate heat sinks. [Actuation of the RPS when the reactor is critical is reportable under 10CFR50.72 (b)(2)(iv)(B)][2]	60 Day LER

[2] Invalid system actuations and invalid trips/scrams when sub-critical may be reported by means of a phone call, rather than a written LER, within the 60-day period.

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10CFR50.72 and 10CFR50.73 MATRIX

10CFR50.72	hrs	10CFR50.73	LER
(b)(3)(v) Any event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident	8	**(a)(2)(v)** Any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident	60 Day LER
(b)(3)(vi) Events covered in paragraph (b)(3)(v) of this section may include one or more procedural errors, equipment failures, and/or discovery of design, analysis, fabrication, construction, and/or procedural inadequacies. However, individual component failures need not be reported pursuant to paragraph (b)(3)(v) of this section if redundant equipment in the same system was operable and available to perform the required safety function. ** An LER is required for an event or condition that could have prevented the fulfillment of the safety function of structures and systems defined in the rules. If the event or condition could have prevented fulfillment of the safety function at the time of discovery, and if it is not reported under 10CFR50.72(a), (b)(1), or (b)(2), an ENS notification is required under (b)(3)	**	**(a)(2)(vi)** Events covered in paragraph (a)(2)(v) of this section may include one or more procedural errors, equipment failures, and/or discovery of design, analysis, fabrication, construction, and/or procedural inadequacies. However, individual component failures need not be reported pursuant to paragraph (a)(2)(v) of this section if redundant equipment in the same system was operable and available to perform the required safety function.	**
There is no corresponding requirement in 10CFR50.72.		**(a)(2)(vii)** Any event where a single cause or condition caused at least one independent train or channel to become inoperable in multiple systems or two independent trains or channels to become inoperable in a single system designed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident.	60 day LER

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10CFR50.72 and 10CFR50.73 MATRIX

10CFR50.72	hrs	10CFR50.73	LER
Refer to the plant's Emergency Plan regarding declaration of an Emergency Class. Refer to 10CFR50.72(b)(2)(xi) below regarding a news release or notification of another agency. Refer to 10CFR20.2202 regarding events reportable under that section.		**(a)(2)(viii)** (A) Any airborne radioactive release that, when averaged over a time period of 1 hour, resulted in airborne radionuclide concentrations in an unrestricted area that exceeded 20 times the applicable concentration limits specified in appendix B to part 20, table 2, column 1. **(a)(2)(viii)** (B)Any liquid effluent release that, when averaged over a time period of 1 hour, exceeds 20 times the applicable concentrations specified in appendix B to part 20, table 2, column 2, at the point of entry into the receiving waters (i.e., unrestricted area) for all radionuclides except tritium and dissolved noble gases.	60 day LER
		(a)(2)(ix)(A) Any event or condition that as a result of a single cause could have prevented the fulfillment of a safety function for two or more trains or channels in different systems that are needed to: *(1)* Shut down the reactor and maintain it in a safe shutdown condition; *(2)* Remove residual heat; *(3)* Control the release of radioactive material; or *(4)* Mitigate the consequences of an accident.	60 day LER
		(a)(2)(ix)(B) Events covered in paragraph (ix)(A) of this section may include cases of procedural error, equipment failure, and/or discovery of a design, analysis, fabrication, construction, and/or procedural inadequacy. However, licensees are not required to report an event pursuant to paragraph (ix)(A) of this section if the event results from: *(1)* A shared dependency among trains or channels that is a natural or expected consequence of the approved plant design; or *(2)* Normal and expected wear or degradation.	60 day LER
Refer to the plant's Emergency Plan regarding declaration of an Emergency Class.		**(a)(2)(x)** Any event that posed an actual threat to the safety of the nuclear power plant or significantly hampered site personnel in the performance of duties necessary for the safe operation of the nuclear power plant including fires, toxic gas releases, or radioactive releases.	60 day LER
(b)(3)(xii) Any event requiring the transport of a radioactively contaminated person to an offsite medical facility for treatment.	8	*There is no corresponding requirement in 10CFR50.73.*	

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10CFR50.72 and 10CFR50.73 MATRIX

10CFR50.72	hrs	10CFR50.73	LER
(b)(3)(xiii) Any event that results in a major loss of emergency assessment capability, offsite response capability, or offsite communications capability (e.g., significant portion of control room indication, Emergency Notification System, or offsite notification system).	8	*There is no corresponding requirement in 10CFR50.73.*	
c) Followup Notification. With respect to the telephone notifications made under Paragraphs (a) and (b) of this section, in addition to making the required initial notification, each licensee, shall during the course of the event: (1) Immediately report: (i) any further degradation in the level of safety of the plant or other worsening plant conditions, including those that require the declaration of any Emergency Classes, if such a declaration has not been previously made, or (ii) any change from one Emergency Class to another, or (iii) a termination of the Emergency Class. (2) Immediately report: (i) the results of ensuing evaluations or assessments of plant conditions, (ii) the effectiveness of response or protective measures taken, and (iii) information related to plant behavior that is not understood. (3) Maintain an open, continuous communication channel with the NRC Operations Center upon request by the NRC.			

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SYSTEM ACTUATIONS - 10CFR50.72(b)(3)(iv)

An event that results or should have resulted in a discharge of the ECCS into the RCS as a result of a valid signal, or an event involving a critical scram, is reportable under 10 CFR 50.72(b)(2)(iv) (a 4-hour report) unless the actuation resulted from and was part of a preplanned sequence.

A valid actuation of any of the systems named in 10CFR50.72(b)(3)(iv)(B) is reportable under 10CFR50.72(b)(3)(iv)(A) [an 8-hour report] unless the actuation resulted from and was part of a pre-planned sequence during testing or reactor operation. This report should be made for most unplanned reactor trips due to the start of Auxiliary Feedwater either manually or automatically.

A system actuation should be apparent at the time of occurrence. Therefore, if all events are reported properly, it is expected that all reports under 10 CFR 50.72 are as a result of an ongoing condition.

An actuation of any of the systems named in 10CFR50.73(a)(2)(iv)(B) is reportable under 10CFR50.73(a)(2)(iv)(A) [a 60-day report] unless the actuation resulted from and was part of a pre-planned sequence during testing or reactor operation or the actuation was invalid and occurred while the system was properly removed from service or occurred after the safety function had been already completed. As indicated in 10CFR50.73(a)(1), in the case of an invalid actuation reported under 10CFR50.73(a)(2)(iv)(A) other than actuation of the reactor protection system (RPS) when the reactor is critical the licensee may, at its option, provide a telephone notification to the NRC Operations Center within 60 days after discovery of the event instead of submitting a written LER. In these cases the telephone report:

(1) Is not considered an LER.

(2) Should identify that the report is being made under 10CFR50.73(a)(2)(iv)(A).

(3) Should provide the following information:

(a) The specific train(s) and system(s) that were actuated.

(b) Whether each train actuation was complete or partial.

(c) Whether or not the system started and functioned successfully.

These paragraphs require events to be reported whenever one of the specified systems actuates either manually or automatically. They are based on the premise that these systems are provided to mitigate the consequences of a significant event and, therefore: (1) they should work properly when called upon, and (2) they should not be challenged frequently or unnecessarily. The Commission is interested both in events where a system was needed to mitigate the consequences of an event (whether or not the equipment performed properly) and events where a system actuated unnecessarily.

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Events involving ECCS discharge to the vessel are generally more serious than actuations without discharge to the vessel. Therefore, this reporting criterion is a 4-hour report. Valid signals that should have resulted in a discharge of the ECCS into the RCS but did not due to some component that had failed or an operator action that was taken are reportable under 10 CFR 50.72(b)(2)(iv). For example, if a valid ECCS signal was generated by plant conditions and the operator put all ECCS pumps in pull-to-lock position, although no ECCS discharge occurred, the event is reportable under 10 CFR 50.72(b)(2)(iv).

Actuations that need not be reported are those initiated for reasons other than to mitigate the consequences of an event (e.g., at the discretion of the licensee as part of a preplanned procedure).

The intent is to require reporting actuation of systems that mitigate the consequences of significant events. Usually, the staff does not consider this to include single component actuations because single components of complex systems, by themselves, usually do not mitigate the consequences of significant events. However, in some cases a component is sufficient to mitigate the event (i.e., perform the safety function) and its actuation is, therefore, reportable. This position is consistent with the statement that the reporting requirement is based on the premise that these systems are provided to mitigate the consequences of a significant event.

Single trains do mitigate the consequences of events, and, thus, train level actuations are reportable.

In this regard, the staff considers actuation of an EDG to be actuation of a train--not actuation of a single component -- because an EDG mitigates the event (performs the safety function).

The staff also considers intentional manual actions, in which one or more system components are actuated in response to actual plant conditions resulting from equipment failure or human error, to be reportable because such actions usually mitigate the consequences of a significant event. This position is consistent with the statement that the Commission is interested in events where a system was needed to mitigate the consequences of the event. For example, starting a safety injection (SI) pump in response to a rapidly decreasing pressurizer level or starting high-pressure coolant injection (HPCI) in response to a loss of feedwater is reportable. However, shifting alignment of makeup pumps or closing a containment isolation valve for normal operational purposes is not reportable.

Actuation of multichannel actuation systems is defined as actuation of enough channels to complete the minimum actuation logic. Therefore, single channel actuations, whether caused by failures or otherwise, are not reportable if they do not complete the minimum actuation logic. Note, however, that if only a single logic channel actuates when, in fact, the system should have actuated in response to plant parameters, this is reportable under these paragraphs as well as under 10 CFR 50.72(b)(3)(v) and 10 CFR 50.73(a)(2)(v) (event or condition that could have prevented the fulfillment of the safety function of ....).

With regard to preplanned actuations, operation of a system as part of a planned test or operational evolution need not be reported. Preplanned actuations are those which are expected to actually occur due to preplanned activities covered by procedures. Such actuations are those for which a procedural step or other appropriate documentation indicates the specific actuation is actually expected to occur. Control room personnel are aware of the specific signal generation before its occurrence or indication in the control room. However, if during the test or evolution, the system actuates in a way that is not part of the planned evolution, that actuation should be reported. For example, if the normal reactor shutdown procedure requires that the control rods be inserted by a manual reactor scram, the reactor scram need not be reported. However, if unanticipated conditions develop during the shutdown that cause an automatic reactor scram, such a reactor scram should be reported. The fact that the safety analysis assumes that a system will actuate automatically during an event does not eliminate the need to report that actuation. Actuations that need not be reported are those initiated for reasons other than to mitigate the consequences of an event (e.g., at the discretion of the licensee as part of a planned evolution).

Note that if an operator were to manually scram the reactor in anticipation of receiving an automatic reactor scram, this is reportable just as the automatic scram is reportable.

Valid actuations are those actuations that result from "valid signals" or from intentional manual initiation, unless it is part of a preplanned test. Valid signals are those signals that are initiated in response to actual plant conditions or parameters satisfying the requirements for initiation of the safety function of the system. They do not include those that are the result of other signals. Invalid actuations are, by definition, those that do not meet the criteria for being valid. Thus, invalid actuations include actuations that are not the result of valid signals and are not intentional manual actuations.

Except for critical scrams, invalid actuations are not reportable by telephone under 10CFR50.72. In addition, invalid actuations are not reportable under 10CFR50.73 in any of the following circumstances:

(A) The invalid actuation occurred when the system is already properly removed from service. This means that all requirements of plant procedures for removing equipment from service have been met. It includes required clearance documentation, equipment and control board tagging, and properly positioned valves and power supply breakers.

(B) The invalid actuation occurred after the safety function has already been completed. An example is RPS actuation after the control rods have already been inserted into the core.

If an invalid actuation reveals a defect in the system so the system failed or would fail to perform its intended function, the event continues to be reportable under other requirements of 10 CFR 50.72 and 50.73. When invalid actuations excluded by the conditions described above occur as part of a reportable event, they should be described as part of the reportable event, in order to provide a complete, accurate and thorough description of the event.

A Containment Ventilation Isolation (CVI) is not reportable at CPNPP per 10CFR50.72(b)(3)(iv)(A) or 10CFR50.73(a)(2)(iv)(A) as a manual or automatic actuation of the systems listed in 10CFR50.72(b)(3)(iv)(B) or 10CFR50.73(a)(2)(iv)(B) because it is not a general containment isolation that involves more than one system.

At CPNPP, an actuation of the Containment Air Recirculation and Cooling System fans, Control Rod Drive Mechanism fans, or Neutron Detector Well fans is not reportable per 10CFR50.72(b)(3)(iv)(B) or 10CFR50.73(a)(2)(iv)(B) because they are not credited in the CPNPP accident analysis.

LOSS OF EMERGENCY ASSESSMENT PREPAREDNESS CAPABILITIES – 10CFR50.72(b)(3)(xiii)

This reporting requirement pertains to events that result in a major loss of emergency assessment capability, offsite response capability, or offsite communications capabilities. The loss of these capabilities could substantially impair a licensee's, or offsite officials', ability to respond to an emergency if one were to occur or has occurred. The focus of this reporting requirement is in the loss of capabilities to perform functions identified in the respective emergency plan. Failures of individual systems or facilities that comprise these capabilities are reportable only to the extent that these failures meet the above threshold.
Notifying the NRC of these events permits the NRC to consider implementing compensatory measures and to more completely assess the consequences of such a loss should it occur during an accident or emergency. The following are examples of equipment or facilities that may be encompassed by this reporting requirement:

Emergency Assessment Capabilities
– safety parameter display system (SPDS)
– primary emergency response facilities (ERFs)
– plant monitors necessary for accident assessment

Offsite Response Capabilities
– public prompt notification system (s) including sirens (primary system)

Offsite Communication Capabilities
– ENS
– other emergency communications facilities and equipment used between the licensee's onsite and offsite ERFs, and between the licensee and offsite officials

Losses of the above equipment and other situations should be evaluated for reportability as discussed below.

REPORTABLE EVENT: A MAJOR LOSS OF EMERGENCY ASSESSMENT CAPABILITY

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Note: Review both the RAL and the Basis section information before making a report. An event described by this RAL constitutes a major loss of emergency assessment capability, and thus should be reported to the NRC within 8 hours in accordance with 10CFR50.72(b)(3)(xiii).

RAL # 1

Loss of EMERGENCY ASSESSMENT capability meeting the Unplanned or Planned Event criteria in Tables A, B1, B2 or C.

Table A – Loss of Emergency Classification Capability

Unplanned Event

a. Loss of a structure or equipment, including indications, display systems and annunciators, that prevents the evaluation of **ALL** EALs for an emergency INITIATING CONDITION.

Planned Event

a. Loss of a structure or equipment, including indications, display systems and annunciators, that prevents the evaluation of **ALL** EALs for an emergency INITIATING CONDITION for greater than 24 hours.

AND

b**. ANY** of the following:

1. No VIABLE COMPENSATORY MEASURE is in place.

OR

2. Lost structures or equipment necessary to evaluate at least one EAL are not expected to be restored within 72 hours from the start of the outage.

OR

3. Lost structures or equipment necessary to evaluate at least one EAL are not restored within 72 hours from the start of the outage.

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Table B1 – UNPLANNED Loss of Emergency Response Facilities and Equipment

a. Loss of a structure or equipment that would prevent the performance of EMERGENCY ASSESSMENT in **ANY** of the following ERFs if an emergency were to occur:

- Control Room
- Primary Technical Support Center
- Primary Emergency Operations Facility

AND

b. The capability to perform EMERGENCY ASSESSMENT was not restored within the RESTORATION TIME specified in Table B1-1.

Table B1-1

ERF	RESTORATION TIME
Control Room	None
Primary Technical Support Center	60 minutes from the time of the unplanned loss, if known, **OR** absent that knowledge, the time-of-discovery.
Primary Emergency Operations Facility	60 minutes from the time of the unplanned loss, if known, **OR** absent that knowledge, the time-of-discovery.

AND

c. The lost EMERGENCY ASSESSMENT capability cannot be performed at a BACKUP EMERGENCY RESPONSE FACILITY.

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Table B2 – PLANNED Loss of Emergency Response Facilities and Equipment

a. Loss of a structure or equipment, for greater than 24 hours, which would prevent the performance of EMERGENCY ASSESSMENT in **ANY** of the following ERFs if an emergency were to occur.

- Control Room
- Primary Technical Support Center
- Primary Emergency Operations Facility

AND

b. **ANY** of the following:

1. (a) The capability to perform EMERGENCY ASSESSMENT cannot be restored within the RESTORATION TIME specified in Table B2-1.

Table B2-1

ERF	RESTORATION TIME
Control Room	None
Primary Technical Support Center	60 minutes following an emergency declaration, should one occur.
Primary Emergency Operations Facility	60 minutes following an emergency declaration, should one occur.

AND

(b) No VIABLE COMPENSATORY MEASURE is in place.

AND

(c) The lost EMERGENCY ASSESSMENT capability cannot be performed at an ALTERNATE FACILITY.

OR

2. The lost structure or equipment is not expected to be restored within 72 hours from the start of the outage.

OR

3. The lost structure or equipment is not restored within 72 hours from the start of the outage.

AND

c. The lost EMERGENCY ASSESSMENT capability cannot be performed at a BACKUP EMERGENCY RESPONSE FACILITY.

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Table C – Loss of Radiological Assessment Capability

Unplanned Event
a. Loss of a structure or equipment that would prevent the performance of RADIOLOGICAL ASSESSMENT for **ANY** of the following assessment options/types:
- Monitored Unit Vent Release
- Unmonitored Containment Release
- Monitored S/G Tube Rupture Release
- Unmonitored S/G Tube Rupture Release

Planned Event
a. Loss of a structure or equipment that would prevent the performance of RADIOLOGICAL ASSESSMENT for **ANY** of the following assessment options/types for greater than 24 hours:
- Monitored Unit Vent Release
- Unmonitored Containment Release
- Monitored S/G Tube Rupture Release
- Unmonitored S/G Tube Rupture Release

AND

b. **ANY** of the following:
1. No VIABLE COMPENSATORY MEASURE is in place.

OR

2. The lost structure or equipment is not expected to be restored within 72 hours from the start of the outage.

OR

3. The lost structure or equipment is not restored within 72 hours from the start of the outage.

Basis for the Major Loss Of Emergency Assessment Capability RAL:
This Reportable Event addresses a major loss of EMERGENCY ASSESSMENT capability such that a response function necessary for determining accident or event consequences, and appropriate measures for mitigation and protection of the public, is significantly impaired if an emergency were to occur. A report is required for an ongoing condition that meets the criteria in one of the RAL Tables above, as well as such a condition that occurred within 3 years of the date of discovery.

A degraded capability exists when a METHOD(S) used to perform an EMERGENCY ASSESSMENT function is unavailable but the reporting criteria contained in the applicable RAL Table above are not met.

A degraded EMERGENCY ASSESSMENT capability should not be reported. Examples of a degraded condition are provided below.

EMERGENCY ASSESSMENT capability subsumes the functions to classify an emergency and perform RADIOLOGICAL ASSESSMENTS; however, separate RALs are included to better address the unique aspects of these functions and related industry operating experience. Refer to Tables A and C, respectively. This approach to the presentation of information notwithstanding, users should evaluate a structure or equipment loss against the criteria in all Tables.

The criteria in the RAL Tables distinguish between losses which are planned and unplanned. A planned loss is one that results from a scheduled work activity such as component maintenance, testing, modification or replacement. An unplanned loss typically involves the failure of a structure or piece of equipment.

A VIABLE COMPENSATORY MEASURE is implemented as part of a planned activity. It need not meet the same design or operating requirements as the normally used METHODS; however, its effectiveness should be sufficient to ensure that the supported emergency response function is accomplished during an actual emergency, albeit in a possibly degraded manner. A VIABLE COMPENSATORY MEASURE must be proceduralized, i.e., the necessary instructions to perform a function must exist in a document that would be followed by response personnel should an emergency occur. A VIABLE COMPENSATORY MEASURE cannot rely upon “skill-of-the-craft” or individual judgment.

It is recognized that the performance of a VIABLE COMPENSATORY MEASURE may require more time to complete than a normally used METHOD(S) (e.g., performance of a sample analysis vs. a radiation monitor reading). The fact that a VIABLE COMPENSATORY MEASURE requires more time to implement than a normally used METHOD(S) does not automatically mean that the associated EMERGENCY ASSESSMENT capability has been lost. The time necessary to implement a VIABLE COMPENSATORY MEASURE should not be unreasonably long and minimized to the degree practical.

<u>Discussion of Table A – Loss of Emergency Classification Capability</u>
Table A addresses a loss of the capability to obtain parameter values or information necessary for the evaluation of EAL thresholds for a given IC, such that an emergency could not be declared per that IC. In cases where multiple EALs are provided for the IC, the loss of the capability to evaluate one or more of them constitutes a degraded capability so long as one or more of them can still be evaluated, and an emergency could be declared per that IC. In addition, given that the readings from certain radiation monitors may be used to perform a RADIOLOGICAL ASSESSMENT, the loss of a radiation monitor should also be assessed using the criteria in Table C.

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Each IC in the Fission Product Barrier Table has multiple fission product barrier thresholds. Each of these thresholds should be treated as an EAL for reporting evaluation purposes. To be reportable, an event would need to involve the loss of all the thresholds in a given LOSS or POTENTIAL LOSS column in the EAL Fission Product Barrier Matrix in EPP-201, exclusive of the "Judgment" thresholds in row F of the matrix.

Events that should be assessed using the Table A criteria include those involving a loss of data acquisition, computation and display systems at the Technical Support Center (TSC) or Emergency Operations Facility (EOF) where such systems support emergency classification. Such events should also be assessed against the appropriate Table B1 (unplanned) or B2 (planned) criteria, and related Basis information.

It is recognized that the assessment of some EALs may require more time than others to complete (e.g., performance of a sample analysis vs. a radiation monitor reading). The time necessary to perform an EAL assessment is not a factor in determining whether a loss is reportable.

Two examples are provided for clarification:

1. An IC with multiple EALs that assess the same condition: A site has an IC for high RCS radioactivity with two EALs – one based on a letdown monitor reading and one based on a sample analysis. The monitor is removed from service for maintenance. This event represents a degraded condition because the IC can still be evaluated using the sample analysis data; it is not reportable. If a concurrent failure were to occur that prevented the collection or analysis of an RCS sample, then both EALs could not be evaluated and, thus, the IC could not be evaluated. This event is reportable.

2. An IC with multiple EALs that assess different conditions: A site has an IC for natural or manmade hazards with 4 EALs – one for high wind speed, one for a seismic event, one for an explosion and one for flooding (i.e., only one EAL for assessing each condition). The seismic monitoring system suffers a failure such that the one seismic-related EAL cannot be evaluated. This event is reportable because the remaining EALs under the IC assess conditions that are unrelated to a seismic event.

The criterion(ia) for initiating a METHOD to assess an EAL using indications available from sources outside the Control Room should be proceduralized; initiation of the METHOD should not be dependent upon "skill-of-the-craft" or individual judgment. For example, consider a site with two EALs related to the plant vent – one using a radiation monitor reading and the other using the results of an effluent sample analysis. The criteria for requiring initiation of the plant vent sampling process should be defined in a procedure.

Discussion of Tables B1 and B2 for Loss of Emergency Response Facilities and Equipment

Tables B1 and B2 address an unplanned or planned loss of a structure or equipment that results in the inability to perform EMERGENCY ASSESSMENT at an ERF. These RALs should be evaluated following a reported or planned degradation of any of the following items to determine if a loss of EMERGENCY ASSESSMENT capability has occurred:

- Structural integrity
- Lighting
- Power sources
- Data acquisition, computation and display systems; including those used for RADIOLOGICAL ASSESSMENT (dose projection) purposes
- Heating, Ventilation and Air Conditioning (HVAC) systems and components
- Habitability systems and components (e.g., HEPA or charcoal filters)
- Unique design features necessary for facility operation (e.g., flooding protection)
- Any other item that could render an EMERGENCY ASSESSMENT function unavailable

As used in these Tables, an inability to perform EMERGENCY ASSESSMENT should not be assumed to have occurred simply because a structure or equipment design parameter is exceeded or feature nonfunctional. Rather, the decision should be based on whether or not ERO personnel could effectively perform EMERGENCY ASSESSMENT functions within the facility, using the equipment and data available. This decision should consider both the ability to activate the facility as well as the capability for protracted operation under emergency conditions.

The following two examples are provided for clarification:

1. An ERF has two METHODS for supplying electrical power - an offsite power source and a backup generator capable of powering all loads needed for the performance of EMERGENCY ASSESSMENT functions. An unplanned event involving a loss of power to the ERF is reportable only if both the offsite power source and the backup power generator are simultaneously unavailable, and the other criteria in Table B1 are met. The unavailability of the offsite power source alone, or the backup power generator alone, represents a degraded condition and would not require a report.

2. Procedures describe one METHOD for providing plant data to ERFs as the Safety Parameter Display System (SPDS) and another METHOD that relies upon manual actions (e.g., use of a communicator). An unplanned event involving a loss of the SPDS is reportable only if the ability to perform the manual METHOD was simultaneously unavailable, and the other criteria in Table B1 are met. The unavailability of

the SPDS alone, or the manual METHOD alone, represents a degraded condition and a report is not required. If a licensee has an ALTERNATE FACILITY or a BACKUP ERF that is capable of performing the functions of the primary facility, consistent with the Table B1 and B2 criteria, then EMERGENCY ASSESSMENT is not significantly impaired during the period that the primary facility is not available. As a result, NRC action or awareness is not likely warranted in such scenarios, and therefore a report is not needed.

A report is not required if the lost capability affects only an ALTERNATE FACILITY or a BACKUP ERF, and the primary ERF remains available.

Since the Control Room is always activated, a RESTORATION TIME does not apply to this facility.

Discussion of Table C – Loss of Radiological Assessment Capability

Table C addresses the loss of a structure or equipment that provides the parameter values or information necessary for performing a RADIOLOGICAL ASSESSMENT for a given assessment option/type during an emergency. In cases where multiple METHODS for obtaining data or information are provided for given assessment option/type, the loss of one or more METHODS constitutes a degraded capability so long as one or more of them can still be performed. In addition, given that certain radiation monitor readings are specified in EALs, the loss of a radiation monitor should also be assessed using the criteria in Table A.

It is recognized that some backup/alternate METHODS used to provide data and information for a RADIOLOGICAL ASSESSMENT may require more time than others to complete (e.g., performance of a sample analysis vs. a radiation monitor reading). The time necessary to implement a backup/alternate METHOD is not a factor in determining whether a loss is reportable.

The inability to perform RADIOLOGICAL ASSESSMENT at an ERF is evaluated in accordance with Tables B1 and B2, since it is a sub-function of EMERGENCY ASSESSMENT. Table C primarily addresses the loss of structures and equipment that provide inputs to a RADIOLOGICAL ASSESSMENT (e.g., those used to ascertain radiation levels, radiological release rates or meteorological parameters). The following examples are provided for clarification:

> A site has an offsite dose assessment process that employs three options/types – plant vent, main steam line and containment source term. Each option/type has two performance METHODS described in the site emergency plan and/or an implementing procedure described in the emergency plan. Likewise, the site possesses two METHODS for obtaining the meteorological data necessary

to perform a RADIOLOGICAL ASSESSMENT for any release option/type. The plant vent monitor has two detectors and associated channels, a low-range and a high-range; the low-range can provide data supporting emergency classifications up to Alert level, and the high-range from the Site Area Emergency through the General Emergency level.

Case 1: The high-range channel fails (becomes nonfunctional) while the low-range channel remains in service. The low-range channel is NOT an acceptable METHOD to compensate for the loss of the high-range channel because it cannot provide data throughout the range necessary to evaluate all emergency classification levels. The site's backup METHOD, which uses a "grab"/manual effluent sample process, is available to provide the data normally provided by the high-range channel. This event represents a degraded capability and is not reportable because the plant vent assessment option/type can still be evaluated for all emergency classification levels.

Case 2: Continued from Case 1 – The plant vent low-range channel also fails (becomes nonfunctional); however, the "grab"/manual effluent sample process is available to provide this data as well. This event represents a degraded capability and is not reportable because the plant vent assessment option/type can still be evaluated for all emergency classification levels.

Case 3: Continued from Case 2 – The backup METHOD that relies upon a "grab"/manual effluent sample process becomes unavailable due to the failure of the required analysis equipment; both described METHODS for obtaining radiological data necessary for performing a RADIOLOGICAL ASSESSMENT using the plant vent assessment option/type are now unavailable. This condition represents a loss of EMERGENCY ASSESSMENT capability and is reportable.

Case 4: The plant vent assessment option/type relies upon three meteorological data inputs – upper wind speed, upper wind direction and upper ΔT. The upper wind speed instrument on the primary meteorological tower (the primary METHOD) becomes nonfunctional while the corresponding instrument on the backup tower (the backup METHOD) remains in service. This event represents a degraded capability and is not reportable.

Case 5: Continued from Case 4 – The upper wind speed instrument on the backup meteorological tower becomes nonfunctional; the backup METHOD for obtaining this data is now also lost. All described METHODS for obtaining upper wind speed, which is meteorological data necessary for performing a RADIOLOGICAL ASSESSMENT using the plant vent assessment option/type, are now unavailable. This condition represents a loss of EMERGENCY ASSESSMENT capability and is reportable.

In cases where a radiation monitor has multiple detectors and related channels that provide input data for performing a RADIOLOGICAL ASSESSMENT, and an unplanned failure occurs that removes a detector or channel from service, a loss of RADIOLOGICAL ASSESSMENT capability is considered to have occurred only if the data range of the remaining available detectors and channels is not sufficient to support the evaluation of all EALs associated with that release assessment option/type (e.g., a low-range channel that cannot read a General Emergency-related release rate or concentration from the plant vent), and there is no other data collection METHOD available.

The criterion(ia) for initiating a RADIOLOGICAL ASSESSMENT METHOD using indications available from sources outside the Control Room should be proceduralized; initiation of the METHOD should not be dependent upon “skill-of-the-craft” or individual judgment. For example, consider a site with two METHODS to obtain a plant vent effluent release concentration – one using a radiation monitor reading and the other using the results of an effluent sample analysis. The criteria for requiring initiation of the plant vent sampling process should be defined in a procedure.

Other Information

A time limit of 24-hours has been applied to planned events. If this threshold and the other related RAL criteria are met, the subsequent report allows the NRC to be aware of the situation and determine if additional actions are necessary.

72 hours was included to the RAL Tables to reflect guidance from NUREG-0696, “Functional Criteria for Emergency Response Facilities.” This guidance suggests an equipment unavailability factor of no more than approximately 1% per year, or about 87 hours per year. This was rounded down to 72 hours to align with other NRC reporting criteria.

REPORTABLE EVENT: A MAJOR LOSS OF OFFSITE RESPONSE CAPABILITY

Note: Review both the RALs and the Basis section information before making a report. An event described by one of these RALs constitutes a major loss of offsite response capability, and thus should be reported to the NRC within 8 hours in accordance with 10CFR50.72(b)(3)(xiii).

RAL # 1

a. The occurrence of a significant natural hazard (e.g., earthquake, hurricane, tornado, flood, major winter storms, etc.) or other event of similar scope and impact.

AND

b. The hazard or event results in **ANY** of the following:

1. An ORO agency has provided information indicating that they are unable to implement protective measures for the public as described in their emergency plan if an actual emergency were to occur (e.g., key evacuation routes are impassable, loss of response infrastructure, etc.).

OR

2. ERO personnel coming from offsite locations could not report to their onsite response locations within 60 minutes if an actual emergency were to occur.

OR

3. **ANY** of the ERFs listed in Table A could not be activated within the specified timeframes if an actual emergency were to occur.

Table A

ERFs	Timeframe
Primary Technical Support Center	60 minutes
Primary Operational Support Center	60 minutes
Primary Emergency Operations Facility	60 minutes

OR

4. Loss of all offsite response capability in any of the categories listed in Table B:

Table B

Local Offsite Support Agencies
Local Fire Departments - DCBE/Acton Volunteer Fire Dept. - Granbury Volunteer Fire Dept. - Indian Harbor Volunteer Fire Dept. - Somervell Co. Fire Dept. Local EMS Departments - Texas Emergency Medical Services

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Table B (Cont'd)

Local Offsite Support Agencies
Local / State / Federal Law Enforcement Departments - Hood Co. Sheriff's Office - Somervell Co. Sheriff's Office - Texas Dept. Of Public Safety SAFER Equipment

RAL # 2

a. Unplanned or planned loss of **ANY** of the 72 sirens within the 10 mile Emergency Planning Zone for greater than one hour such that the loss would affect > 25% of the population.

AND

b. **ANY** of the following:

1. The FEMA-approved backup alerting METHOD(S) cannot be implemented for the area affected by the lost primary ANS equipment.

OR

2. The primary ANS equipment is not expected to be returned to service within 24 hours.

OR

3. The primary ANS equipment was not returned to service within 24 hours.

Basis for the Major Loss Of Offsite Response Capability RAL:
This Reportable Event addresses a major loss of offsite response capability that could prevent the on-shift staff from obtaining needed response assistance or offsite officials from implementing key functions needed for protection of the public if an emergency were to occur. The loss of an individual structure or piece of equipment that supports performance of the offsite response capability is reportable only to the extent that it meets an RAL threshold; a degraded capability caused by a failure or planned activity should not be reported. A report is required for an ongoing condition that meets one the RALs above, as well as such a condition that occurred within 3 years of the date of discovery.

RAL #1 is met when the licensee has confirmed that an event has caused conditions which meet any of the RAL criteria. Because a significant natural hazard is an unplanned event, no allowed outage duration or RESTORATION TIMES are specified.

As used in RAL #1, an ORO agency should be one with primary responsibility for coordinating and implementing offsite emergency measures.

Impediments to evacuation such as fog, snow, and ice, should generally not be reported if they are within the respective capabilities of the licensee, state, or local officials to resolve or mitigate. Rather, the reporting requirement is intended to apply to more significant events such as the conditions around the Turkey Point

Nuclear Plant after Hurricane Andrew struck in 1992 or the conditions around the Cooper Nuclear Station during the Midwest floods of 1993. During this type of event, a licensee should periodically gather and assess information available from OROs and other sources to determine if a loss offsite response capability has occurred.

For RAL #2 – an unplanned ANS outage - An unplanned outage would typically be initiated by the failure of a structure or piece of equipment. The specified durations begin when the failure occurred, if firm evidence of the failure time exists. This includes instances where a failure time is logged by an automated diagnostics and reporting technology for subsequent and periodic review by personnel (e.g., a data logger that captures routine siren feedback results). Absent firm evidence of a failure time, the specified durations begin with the time-of-discovery.

For RAL #2 – a planned ANS outage - A planned outage is one that results from a scheduled work activity such as component maintenance, testing, modification or replacement. The specified durations begin when the ANS component(s) are removed from service.

For RAL #2, the unplanned and planned loss cases have been combined. The one-hour condition duration reflects guidance provided in NUREG-1022. Because the FEMA-approved backup alerting METHOD(S) does not meet the performance criteria of 10 CFR 50, Appendix E, Section IV.D.3, a time limit of 24-hours has been applied. If this threshold is met, the subsequent report will allow the NRC to discuss the situation with FEMA and determine if additional actions are necessary.

REPORTABLE EVENT: A MAJOR LOSS OF OFFSITE COMMUNICATIONS CAPABILITY

Note: Review both the RAL Tables and the Basis section information before making a report. An event described by one of these RALs constitutes a major loss of offsite communications capability, and thus should be reported to the NRC within 8 hours in accordance with 10CFR50.72(b)(3)(xiii).

RAL #1

Loss of an offsite communications capability meeting the Unplanned or Planned Event criteria in Tables A, B, C, D, E or F.

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Table A – Loss of the Emergency Notification System

ENS METHOD	Control Room	Primary TSC	Primary EOF
ENS Line	✓	✓	✓
Satellite phones	✓	✓	✓
VOIP Phones	✓	✓	✓
RESTORATION TIME	None	60 minutes	60 minutes

Unplanned Event
a. **ALL** the ENS METHODS checked above for a given facility are lost.
Planned Event
a. **ALL** the ENS METHODS checked above for a given facility are lost.
AND
b. **ANY** of the following:
1. (a) At least one METHOD could not be restored to service within the specified RESTORATION TIME following an emergency declaration, should one occur.
AND
(b) No VIABLE COMPENSATORY MEASURE is in place.
OR
2. At least one METHOD is not expected to be restored within 72 hours from the start of the outage.
OR
3. At least one METHOD is not restored within 72 hours from the start of the outage.

Table B – Loss of the Health Physics Network

HPN METHOD	Primary TSC	Primary EOF
HPN Line	✓	✓
Satellite phones	✓	✓
VOIP Phones	✓	✓
RESTORATION TIME	60 minutes	60 minutes

Unplanned Event
a. **ALL** the HPN METHODS checked above for a given facility are lost.

Planned Event
a. **ALL** the HPN METHODS checked above for a given facility are lost.
AND
b. **ANY** of the following:
1. (a) At least one METHOD could not be restored to service within the specified RESTORATION TIME following an emergency declaration, should one occur.
AND
(b) No VIABLE COMPENSATORY MEASURE is in place.

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Table B – Loss of the Health Physics Network (Cont'd)

OR
2. At least one METHOD is not expected to be restored within 72 hours from the start of the outage.
OR
3. At least one METHOD is not restored within 72 hours from the start of the outage.

Table C – Loss of ORO Communications

Communications METHOD	Control Room	Primary TSC	Primary EOF
Satellite phones	✓	✓	✓
Site UHF radio system	✓	✓	✓
VOIP Phones	✓	✓	✓

Unplanned Event
a. **ALL** the ORO communications METHODS checked above for a given facility are lost.

Planned Event
a. **ALL** the ORO communications METHODS checked above for a given facility are lost.
AND
b. **ANY** of the following:
1. (a) At least one METHOD could not be restored to service within 15 minutes of an emergency declaration, should one occur.
AND
(b) No VIABLE COMPENSATORY MEASURE is in place.
OR
2. At least one METHOD is not expected to be restored within 72 hours from the start of the outage.
OR
3. At least one METHOD is not restored within 72 hours from the start of the outage.

Table D – Loss of ERO Notifications

ERO Notification METHODS
Intra-plant phone systems (PBX/VoIP)
Public telephone system
Cellular telephones
Satellite phones
ERO pagers
ERO self-activation

Unplanned Event
a. **ALL** the ERO notification METHODS listed above are lost.

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Table D – Loss of ERO Notifications (Cont'd)

Planned Event
a. **ALL** the ERO notification METHODS listed above are lost.
AND
b. **ANY** of the following:
1. (a) At least one METHOD could not be restored to service within 15 minutes of an emergency declaration, should one occur.
AND
(b) No VIABLE COMPENSATORY MEASURE is in place.
OR
2. At least one METHOD is not expected to be restored within 72 hours from the start of the outage.
OR
3. At least one METHOD is not restored within 72 hours from the start of the outage.

Table E – Loss of ERF Communications

Communications METHOD	Control Room	Primary TSC	Primary EOF
Satellite phones	✓	✓	✓
Site UHF radio system	✓	✓	✓
Site PA system	✓	✓	✓
Intra-plant sound powered phones	✓	✓	
VOIP Phones	✓	✓	✓
RESTORATION TIME	None	60 minutes	60 minutes

Unplanned Event
a. **ALL** the ERF communications METHODS checked above for a given facility are lost.

Planned Event
a. **ALL** the ERF communications METHODS checked above for a given facility are lost.
AND
b. **ANY** of the following:
1. (a) At least one METHOD could not be restored to service within the specified RESTORATION TIME following an emergency declaration, should one occur.
AND
(b) No VIABLE COMPENSATORY MEASURE is in place.
OR
2. At least one METHOD is not expected to be restored within 72 hours from the start of the outage.
OR
3. At least one METHOD is not restored within 72 hours from the start of the outage.

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Table F – Loss of ERO Offsite Monitoring Team Communications

ERO Offsite Monitoring Team (OMT) Communications METHODS
Satellite phones
Site UHF radio system
Unplanned Event a. **ALL** the offsite monitoring team communications METHODS listed above are lost. Planned Event a. **ALL** the offsite monitoring team communications METHODS listed above are lost. **AND** b. **ANY** of the following: 1. (a) At least one METHOD could not be restored to service within 60 minutes of an emergency declaration, should one occur. **AND** (b) No VIABLE COMPENSATORY MEASURE is in place. **OR** 2. At least one METHOD is not expected to be restored within 72 hours from the start of the outage. **OR** 3. At least one METHOD is not restored within 72 hours from the start of the outage.

Basis for the Major Loss Of Offsite Communications Capability RAL:
This Reportable Event addresses a major loss of offsite communications capability that could prevent a licensee from performing required communications with federal, state, and local officials; or between the site and ERO personnel at offsite locations. A report is required for an ongoing condition that meets the criteria in one of the RAL Tables above, as well as such a condition that occurred within 3 years of the date of discovery.

A degraded capability exists when a METHOD(S) used to perform a communications function is unavailable but the reporting criteria contained in the applicable RAL Table above are not met. A degraded offsite communications capability should not be reported. For example, if an ERF has two METHODS for maintaining communications with an ORO, an unplanned event involving a simultaneous loss of both methods is reportable. The loss of either METHOD alone represents a degraded condition, and thus does not require a report.

The criteria in the RAL Tables distinguish between losses which are planned and unplanned. A planned loss is one that results from a scheduled work activity such as component maintenance, testing, modification or replacement. An unplanned loss typically involves the failure of a structure or piece of equipment.

A VIABLE COMPENSATORY MEASURE is implemented as part of a planned activity. It need not meet the same design or operating requirements as the normally used METHODS; however, its effectiveness should be sufficient to ensure that the supported emergency response function would be accomplished during an actual emergency, albeit in a possibly degraded manner. A VIABLE COMPENSATORY MEASURE must be proceduralized, i.e., the necessary instructions to perform a function must exist in a document that shall be followed by response personnel should an emergency occur. A VIABLE COMPENSATORY MEASURE cannot rely upon “skill-of-the-craft” or individual judgment.

It is recognized that the performance of a VIABLE COMPENSATORY MEASURE may require more time to complete than a normally used METHOD(S). The fact that a VIABLE COMPENSATORY MEASURE requires more time to implement that a normally used METHOD(S) does not automatically mean that the associated offsite communications capability has been lost. The time necessary to implement a VIABLE COMPENSATORY MEASURE should not be unreasonably long and minimized to the degree practical.

Since the Control Room is always activated, a RESTORATION TIME does not apply to this facility.

The 72-hour value reflects guidance from NUREG-0696, “Functional Criteria for Emergency Response Facilities.” This guidance suggests an equipment unavailability factor of no more than approximately 1% per year, or about 87 hours per year. This was rounded down to 72 hours to align with other NRC reporting criteria.

ERDS was implemented as a supplement to the ENS in accordance with Appendix E of 10CFR50. The ERDS provides the NRC with the information necessary for performance of its oversight function. The loss of ERDS cannot impair a licensee’s emergency response or communications capabilities during an emergency; therefore, a failure of the ERDS does not constitute a major loss of offsite communication capability and should not be reported.

Although a notification may not be required under 10CFR50.72(b)(3)(xiii) in the event of a loss of the ENS, HPN, or ERDS, the NRC Operations Center should be informed of any failure of NRC-supplied communications equipment so that the NRC may arrange for repair. The commercial telephone number 301-816-5100 may be used to inform the NRC Operations Center of a failed piece of equipment. At the time the failure is reported, the licensee should be prepared to supply the following information to expedite repair: (1) name of contact at location of failure, (2) commercial phone number of contact, (3) location of contact (i.e., street address, building number, room number, etc., and (4) any other information that expedites repair.

If the NRC Operations Center provides the initial notification that an ENS line is out-of-service, then there is no need to make a report provided that another communications METHOD listed in Table A is available.

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SAFETY SYSTEM FUNCTIONAL FAILURES – 10CFR50.72(b)(3)(v)

If the event or condition could have prevented fulfillment of the safety function at the time of discovery, an ENS notification and an LER are required. If it could have prevented fulfillment of the safety function at any time within 3 years of the date of discovery, but not at the time of discovery, only an LER is required. If the event or condition could have prevented fulfillment of the safety function at the time of discovery, and if it is not reported under 10 CFR 50.72(a), (b)(1), or (b)(2), an ENS notification is required under 10 CFR 50.72(b)(3).

This criterion is based on the assumption that safety-related SSCs are intended to mitigate the consequences of an accident. SSCs within scope include only safety-related SSCs required by the TS to be operable that are intended to mitigate the consequences of an accident as discussed in Chapters 6 and 15 of the Final Safety Analysis Report (or equivalent chapters). Accidents are identified as events of moderate frequency, infrequent incidents, or limiting faults as discussed in Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants (LWR Edition)" (or equivalent classifications of the three types of events). The American Nuclear Society (ANS) categorizes these events as Condition II, III, and IV type events.

The level of judgment for reporting an event or condition under this criterion is a reasonable expectation of preventing fulfillment of a safety function. In the discussions that follow, many of which are taken from previous NUREG guidance, several different expressions, such as "would have," "could have," "alone could have," and "reasonable doubt," are used to characterize this standard. In the staff's view, all of these should be judged on the basis of a reasonable expectation of preventing fulfillment of the safety function. A SSC that has been declared inoperable is one in which the SSC capability is degraded to a point where it cannot perform with reasonable expectation or reliability. These criteria cover an event or condition in which scoped in SSCs could have failed to perform their intended function because of one or more personnel errors, including procedure violations; equipment failures; inadequate maintenance;
or design, analysis, fabrication, equipment qualification, construction, or procedural deficiencies and no redundant equipment in the same system was operable.

As a result, for SSCs within the scope of this criterion, a report is required when 1) there is a determination that the SSC is inoperable in a required mode or other specified condition in the TS Applicability, 2) the inoperability is due to one or more personnel errors, including procedure violations; equipment failures; inadequate maintenance; or design, analysis, fabrication, equipment qualification, construction, or procedural deficiencies, and 3) no redundant equipment in the same system was operable. For guidance on determining whether a SSC is operable, see IMC-0326. Operable but nonconforming or degraded conditions are not considered reportable under this criterion.

As a result, reports are not required when systems are declared inoperable as part of a planned evolution for maintenance or surveillance testing when done in accordance with an approved procedure and the plant's TS (unless a condition is discovered that would have resulted in the system being declared inoperable). In addition, unless a condition is discovered that would have resulted in the system being declared inoperable, reports are not required when systems are declared inoperable solely as a result of Required Actions for which the bases is the assumption of an additional random single failure (i.e. Westinghouse STS, Revision 4, LCO 3.8.1, "AC Sources – Operating," Required Actions A.2, B.2, or C.1).

The event shall be reported regardless of whether or not an alternate safety system could have been used to perform the safety function. For example, if the onsite power system was declared inoperable due to equipment failures, the event is reportable, even if the offsite power system remained operable.

For systems that include three or more trains, the inoperability of two or more trains should be reported if, in the judgment of the licensee, the remaining operable trains could not mitigate the consequences of an accident.

There are a limited number of single-train systems that perform safety functions (e.g., the HPCI system in BWRs). For such systems, inoperability of the single train is reportable even though the plant TS may allow such a condition to exist for a limited time.

If the retraction or cancellation of a report under this criterion is due to a revised operability determination, the retraction or cancellation should discuss the basis for why the operability determination was revised, and why it is believed that system operability was never lost (i.e., in lieu of the initial determination).

ATTACHMENT 8.D/14

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NONROUTINE REPORT - 14

TITLE: Notification of Termination, Reassignment, Disability, or Illness of a Licensed Operator.

FORMAT: Written report within 30 days of the change of status or of learning of the diagnosis.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR50.74

Each licensee shall notify the Commission in accordance with [10CFR50.4, Written Communication] within 30 days of the following in regard to a licensed operator or senior operator:

(a) Permanent reassignment from the position for which the licensee has certified the need for a licensed operator or senior operator under 10CFR55.31(a)(3) of this chapter;

(b) Termination of any operator or senior operator;

(c) Permanent, disability or illness as described in 10CFR55.25 of this chapter.

From 10CFR55.25

If, during the term of the [Operator's] license, the licensee develops a physical or mental condition that causes the licensee to fail to meet the requirements of 10CFR55.21 of this part [Medical Examinations], the facility licensee shall notify the Commission within 30 days of learning of the diagnosis.

CONTENT: No additional guidance provided.

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ADDITIONAL INFORMATION: For conditions for which a conditional license (as described in 10CFR55.33(b)) is requested, the facility licensee shall provide medical certification on Form NRC 396 to the Commission (as described in 10CFR55.23).

CONTROL ROOM ACTIONS: None

ADDITIONAL RESPONSIBILITIES: The Director, Operations shall ensure that the Manager, Regulatory Affairs is advised of the reportable condition.

FOLLOWUP ACTIONS: The Manager, Regulatory Affairs shall ensure the report is prepared and submitted in accordance with applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 15

TITLE:	Notification of a Felony Conviction of a Licensed Operator
FORMAT:	Written notification within 30 days of a felony conviction.
APPLICABILITY:	Each licensed reactor operator and senior reactor operator at CPNPP is subject to this requirement.
REQUIREMENT:	From 10CFR55.53(g) The licensee shall notify the Commission within 30 days about a conviction for a felony.
CONTENT:	The notification shall contain sufficient information for NRC evaluation.
ADDITIONAL INFORMATION:	None
CONTROL ROOM ACTIONS:	None
FOLLOWUP ACTIONS:	None

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NONROUTINE REPORT - 16

TITLE: Accidental Criticality or Loss of Special Nuclear Material

FORMAT: Notification to the NRC Operations Center via the ENS within 1 hour after discovery.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR70.52 and 72.74(a)

(a) Each licensee shall notify the NRC Operations Center within one hour after discovery of any case of accidental criticality or any loss, other than normal operating loss, of special nuclear material.

(b) Each licensee who possesses one gram or more of contained uranium-235, uranium-233, or plutonium shall notify the NRC Operations Center within one hour after discovery of any loss or theft or unlawful diversion of special nuclear material which the licensee is licensed to possess or any incident in which an attempt has been made or is believed to have been made to commit a theft or unlawful diversion of such material.

CONTENT: As requested during notification, no additional guidance available.

ADDITIONAL INFORMATION: From 10CFR70.52

Reports required under [10CFR73.71] need not be duplicated under the requirements of this section.

CONTROL ROOM ACTIONS: The Shift Manager shall notify the NRC within 1 hour, and ensure that plant management is notified of the event.

FOLLOWUP ACTIONS: None

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NONROUTINE REPORT - 17

TITLE: Accident Notification - Shipment Involving Hazardous Materials

FORMAT: As soon as practical but no later than 12 hours after the occurrence, each person in physical possession of the hazardous material must provide notice by telephone to the National Response Center (NRC) on 800-424-8802 (toll free) or 202-267-2675 (toll call) or online at http://www.nrc.uscg.mil. and shall submit a Hazardous Materials Incident Report on DOT Form F 5800.1 (01/2004) within 30 days of discovery of the incident as described in 49CFR171.15(b) or 49CFR171.16(a).

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR71.5(a)

Each licensee who transports licensed material outside of the confines of its plant or other place of use, or who delivers licensed material to a carrier for transport, shall comply with the applicable requirements of the regulations appropriate to the mode of transport of DOT in 49CFR Parts 170 through 189.

(1) The licensee shall particularly note DOT regulations in the following areas: ...

Accident reporting - 49CFR Part 171.15 and 171.16.

From 49CFR171.15(b)

A telephone report is required whenever any of the following occurs during the course of transportation in commerce (including loading, unloading, and temporary storage):

(1) As a direct result of a hazardous material—
- (i) A person is killed;
- (ii) A person receives an injury requiring admittance to a hospital;
- (iii) The general public is evacuated for one hour or more;
- (iv) A major transportation artery or facility is closed or shut down for one hour or more; or
- (v) The operational flight pattern or routine of an aircraft is altered;

(2) Fire, breakage, spillage, or suspected radioactive contamination occurs involving a radioactive material (see also § 176.48 of this subchapter);

(3) Fire, breakage, spillage, or suspected contamination occurs involving an infectious substance other than a regulated medical waste;

(4) A release of a marine pollutant occurs in a quantity exceeding 450 L (119 gallons) for a liquid or 400 kg (882 pounds) for a solid;

(5) A situation exists of such a nature (e.g. , a continuing danger to life exists at the scene of the incident) that, in the judgment of the person in possession

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of the hazardous material, it should be reported to the NRC even though it does not meet the criteria of paragraphs (b)(1), (2), (3) or (4) of this section; or
(6) During transportation by aircraft, a fire, violent rupture, explosion or dangerous evolution of heat (i.e. , an amount of heat sufficient to be dangerous to packaging or personal safety to include charring of packaging, melting of packaging, scorching of packaging, or other evidence) occurs as a direct result of a battery or battery-powered device.

NOTE TO § 171.15: Under 40 CFR 302.6, EPA requires persons in charge of facilities (including transport vehicles, vessels, and aircraft) to report any release of a hazardous substance in a quantity equal to or greater than its reportable quantity, as soon as that person has knowledge of the release, to DOT's National Response Center at (toll free) 800-424-8802 or (toll) 202-267-2675.

From 49CFR171.16(a)

Each person in physical possession of a hazardous material at the time that any of the following incidents occurs during transportation (including loading, unloading, and temporary storage) must submit a Hazardous Materials Incident Report on DOT Form F 5800.1 (01/2004) within 30 days of discovery of the incident:

(1) Any of the circumstances set forth in § 171.15(b);
(2) An unintentional release of a hazardous material or the discharge of any quantity of hazardous waste;
(3) A specification cargo tank with a capacity of 1,000 gallons or greater containing any hazardous material suffers structural damage to the lading retention system or damage that requires repair to a system intended to protect the lading retention system, even if there is no release of hazardous material;
(4) An undeclared hazardous material is discovered; or
(5) A fire, violent rupture, explosion or dangerous evolution of heat (i.e. , an amount of heat sufficient to be dangerous to packaging or personal safety to include charring of packaging, melting of packaging, scorching of packaging, or other evidence) occurs as a direct result of a battery or battery-powered device.

From 49CFR171.16(c) and (d)

(c) A Hazardous Materials Incident Report must be updated within one year of the date of occurrence of the incident whenever:

(1) A death results from injury caused by a hazardous material;
(2) There was a misidentification of the hazardous material or package information on a prior incident report;

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(3) Damage, loss or related cost that was not known when the initial incident report was filed becomes known; or
(4) Damage, loss, or related cost changes by $25,000 or more, or 10% of the prior total estimate, whichever is greater.

(d) Exceptions. Unless a telephone report is required under the provisions of § 171.15 of this part, the requirements of paragraphs (a), (b), and (c) of this section do not apply to the following incidents:
(1) A release of a minimal amount of material from—
(i) A vent, for materials for which venting is authorized;
(ii) The routine operation of a seal, pump, compressor, or valve; or
(iii) Connection or disconnection of loading or unloading lines, provided that the release does not result in property damage.

CONTENT: From 49CFR171.15(a)

Each notice must include the following information:
(1) Name of reporter;
(2) Name and address of person represented by reporter;
(3) Phone number where reporter can be contacted;
(4) Date, time, and location of incident;
(5) The extent of injury, if any;
(6) Class or division, proper shipping name, and quantity of hazardous materials involved, if such information is available; and
(7) Type of incident and nature of hazardous material involvement and whether a continuing danger to life exists at the scene.

ADDITIONAL INFORMATION: National Response Center (NRC) phone 800-424-8802 (toll free) or 202-267-2675 (toll call) or online at http://www.nrc.uscg.mil

Note that the carrier is programmatically required to notify a Luminant Power representative and DOT of event involving hazardous waste.

In accordance with Texas Administrative Code Title 25 Part 1 Chapter 289 subchapter F Rule 289.257 (p), The shipper shall immediately report by telephone, telegram, mailgram, or facsimile, all radioactive waste transportation accidents to the Texas Department of State Health Services and the local emergency planning committees in the county where the radioactive waste accident occurs.

Texas Department of State Health Services: 512-458-7460
See Listing of Texas Local Emergency Planning Committee phone numbers at http://www.dshs.state.tx.us/tiertwo/pdf/lepccontact.pdf

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Per 49CFR171.16(b) Each person reporting under this section must—
(1) Submit a written Hazardous Materials Incident Report to the Information Systems Manager, PHH-60, Pipeline and Hazardous Materials Safety
Administration, Department of Transportation, East Building, 1200 New Jersey Ave., SE., Washington, DC 20590-0001, or an electronic Hazardous Material Incident Report to the Information System Manager, PHH-60, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, Washington, DC 20590-0001 at http://hazmat.dot.gov ;
(2) For an incident involving transportation by aircraft, submit a written or electronic copy of the Hazardous Materials Incident Report to the FAA Security Field Office nearest the location of the incident; and
(3) Retain a written or electronic copy of the Hazardous Materials Incident Report for a period of two years at the reporting person's principal place of business. If the written or electronic Hazardous Materials Incident Report is maintained at other than the reporting person's principal place of business, the report must be made available at the reporting person's principal place of business within 24 hours of a request for the report by an authorized representative or special agent of the Department of Transportation.

The Shift Manager shall be notified of an accident that occurred during the loading and unloading of hazardous material.

CONTROL ROOM ACTIONS: The Shift Manager shall ensure that the DOT is notified of accidents that occur during loading and unloading hazardous material.

FOLLOWUP ACTIONS: The Radiation Protection Manager shall verify that the carrier reports accidents in accordance with the above requirements for shipments involving low level waste and source material.

For shipments of other radioactive material, instruments and articles which are classified as hazardous materials, the Manager responsible for the shipment shall verify that the carrier reports accidents in accordance with the above requirements.

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NONROUTINE REPORT - 18

TITLE: Reduction in Effectiveness of Authorized Radioactive Material Packaging During Use.

FORMAT: Written notification within 30 days of occurrence

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From GL 91-02

It is suggested that the voluntary submittal of information regarding waste-form mishaps be reported within 30 days of the incident to NRC's Director of the Division of Low-Level Waste Management and Decommissioning and to the designated State disposal-site regulatory authority.

From STA 709, Section 6.8

Mishaps listed in 6.8.2, 6.8.3 and 6.8.4 regarding waste form or container deficiencies shall be reported in accordance with STA 501 and shall be submitted within 30 days of the incident to:

NRC's Director of the Division of Low-Level Waste Management and Decommissioning; and

State Disposal - Site Regulatory Authority

From 10CFR71.95

The licensee shall report to the Director, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555, within 30 days;

(a) Any instance in which there is significant reduction in the effectiveness of any authorized packaging during use; and
(b) Details of any defects with safety significance in the packaging after first use, with the means employed to repair the defects and prevent their recurrence.
(c) Instances in which the conditions of approval in the certificate of compliance were not observed in making a shipment

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NONROUTINE REPORT - 18

CONTENT:	No additional guidance available.
ADDITIONAL INFORMATION:	None
CONTROL ROOM ACTIONS:	None
FOLLOWUP ACTIONS:	The Radiation Protection Manager shall ensure a written report is prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 19

TITLE: Advance Notification of Shipment of Radioactive Waste

FORMAT: Written notification to the office of each state governor 7 days prior to transport of nuclear waste or spent fuel.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR71.97

(a) Except as specified in Paragraph (b) of this section, prior to the transport or delivery to a carrier for transport of licensed material outside the confines of the licensee's plant or other place of use or storage, each licensee shall provide advance notification to the governor of a state, or the governor's designee, of the shipment to, through, or across the boundary of the state.

(b) Advanced notification is required only when:

(1) The licensed material is required by this part to be in Type B packaging for transportation;

(2) The licensed material other than irradiated fuel is being transported to, through, or across state boundaries to a disposal site or to a collection point for transport to a disposal site.

(3) The quantity of licensed material in a single package exceeds the least of the following:

(i) 3,000 times the A_1 value of the radionuclides as specified in appendix A, Table A-1 for special form radioactive material;

(ii) 3,000 times the A_2 value of the radionuclides as specified in appendix A, Table A-1 for normal form radioactive material; or

(iii) 1000 TBq (27,000 Ci).

(c) Procedures for submitting advance notification.

(1) The notification must be made in writing to the office of each appropriate governor or governor's designee and to the Administrator of the appropriate NRC Regional Office listed in appendix A to part 73 of this chapter.

(2) A notification delivered by mail must be postmarked at least 7 days before the beginning of the 7-day period during which departure of the shipment is estimated to occur.

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NONROUTINE REPORT - 19

(3) A notification delivered by messenger must reach the office of the governor or of the governor's designee at least 4 days before the beginning of the 7-day period during which departure of the shipment is estimated to occur.

(i) A list of the names and mailing addresses of the governors' designees receiving advance notification of transportation of nuclear waste was published in the Federal Register on June 30, 1995 (60 FR 34306).

(ii) The list will be published annually in the Federal Register on or about June 30 to reflect any changes in information.

(iii) A list of the names and mailing addresses of the governors' designees is available on request from the Director, Office of State Programs, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

(4) The licensee shall retain a copy of the notification as a record for 3 years.

(d) Information to be furnished in advance notification of shipment. Each advance notification of shipment of irradiated reactor fuel or nuclear waste must contain the following information:

(1) The name, address, and telephone number of the shipper, carrier, and receiver of the irradiated reactor fuel or nuclear waste shipment;

(2) A description of the irradiated reactor fuel or nuclear waste contained in the shipment, as specified in the regulations of DOT in 49 CFR 172.202 and 172.203(d);

(3) The point of origin of the shipment and the 7-day period during which departure of the shipment is estimated to occur;

(4) The 7-day period during which arrival of the shipment at State boundaries is estimated to occur;

(5) The destination of the shipment, and the 7-day period during which arrival of the shipment is estimated to occur; and

(6) A point of contact, with a telephone number, for current shipment information.

(e) Revision notice. A licensee who finds that schedule information previously furnished to a governor or governor's designee in accordance with this section will not be met, shall telephone a responsible individual in the office of the governor of the State or of the governor's designee and inform that individual of the extent of the delay beyond the schedule originally reported. The licensee shall maintain a record of the name of the individual contacted for three years.

(f) Cancellation notice.

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NONROUTINE REPORT - 19

(1) Each licensee who cancels a nuclear waste shipment for which advance notification has been sent, shall send a cancellation notice to the governor of each state or the governor's designee previously notified and to the Regional Administrative Commission Regional Office listed in Appendix A of Part 73 of this chapter.

From 10CFR73.37(f)

Prior to the transport of spent fuel within or through a state a licensee subject to this section shall notify the governor or the governor's designee. The licensee shall comply with the following criteria in regard to a notification:

(1) The notification must be in writing and sent to the office of each appropriate governor or the governor's designee. A notification delivered by mail must be postmarked at least 7 days before transport of a shipment within or through the state. A notification delivered by messenger must reach the office of the governor or the governor's designee at least 4 days before transport of a shipment within or through the state. A list of the mailing addresses of governors and governor's designees is available upon request from the Director, Office of Governmental and Public Affairs, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

(4) A licensee shall notify by telephone or other means a responsible individual in the office of the governor or in the office of the governor's designee of any schedule change that differs by more than 6 hours from the schedule information previously furnished in accordance with 10CFR73.37(f)(3), and shall inform that individual of the number of hours of advance or delay relative to the written schedule information previously furnished.

CONTENT: From 10CFR71.97

(d) Each advance notification of shipment of nuclear waste must contain the following information:
(1) The name, address, and telephone number of the shipper, carrier, and receiver of the nuclear waste shipment;
(2) A description of the nuclear waste contained in the shipment, as required by the regulations of DOT in 49CFR172.202 and 172.203(d);
(3) The point of origin of the shipment and the seven-day period during which departure of the shipment is estimated to occur;
(4) The seven-day period during which arrival of the shipment at state boundaries is estimated to occur;

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NONROUTINE REPORT - 19

(5) The destination of the shipment, and the seven-day period during which arrival of the shipment is estimated to occur; and
(6) A point of contact with a telephone number for current shipment information.
(e) Revision notice. A licensee who finds that schedule information previously furnished to a governor or governor's designee in accordance with this section will not be met, shall telephone a responsible individual in the office of the governor of the State or of the governor's designee and inform that individual of the extent of the delay beyond the schedule originally reported. The licensee shall maintain a record of the name of the individual contacted for three years.
(f) Cancellation notice.
(1) Each licensee who cancels a nuclear waste shipment for which advance notification has been sent, shall send a cancellation notice to the governor of each state or the governor's designee previously notified and to the Regional Administrator of the appropriate Nuclear Regulatory Commission Regional Office listed in Appendix A or Part 73 of this chapter.
(2) The licensee shall state in the notice that it is a cancellation and shall identify the advance notification which is being canceled. The licensee shall retain a copy of the notice as a record for three years.

From 10CFR73.37(f)

(2) The notification must include the following information.
(i) address, and telephone number of the shipper, carrier and receiver.
(ii) A description of the shipment as specified by the Department of Transportation in 49CFR172.202 and 172.203(d)
(iii) A listing of the routes to be used within the state.
(iv) A statement that the information described below in CFR73.37(f)(3) is required by NRC regulations to be protected in accordance with the requirements of CFR73.21.
(3) The licensee shall provide the following information on a separate enclosure to the written notification:
(i) The estimated date and time of departure from the point of origin of the shipment.
(ii) The estimated date and time entry into the governor's state.

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NONROUTINE REPORT - 19

(iii) For the case of a single shipment whose schedule is not related to the schedule of any subsequent shipment, a statement that schedule information must be protected in accordance with the provisions of CFR73.21 until at least 10 days after the shipment has entered or originated within the state.

(iv) For the case of a shipment in a series of shipments whose schedules are related, a statement that schedule information must be protected in accordance with the provisions of CFR73.121 until at least 10 days after the last shipment in the series has entered or originated within the state and an estimate of the date on which the last shipment in the series will enter or originate within the state.

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NONROUTINE REPORT - 19

ADDITIONAL INFORMATION: From 10CFR71.97(c)

(1) The notification must be made in writing to the office of the governor or governor's designee and to the Regional Administrator of the appropriate Nuclear Regulatory Commission Regional Office listed in Appendix A of Part 73 of this chapter.
(2) A notification delivered by mail must be postmarked at least seven days before the beginning of the seven-day period during which departure of the shipment is estimated to occur.
(3) A notification delivered by messenger must reach the office of the governor or of the governor's designee at least four days before the beginning of the seven-day period during which departure of the shipment is estimated to occur.
(i) A list of the names and mailing addresses of the governor's designees receiving advance notification of transportation of nuclear waste was published in the Federal Register on June 30, 1995 (48 FR 30221).
(ii) The list will be published annually in the Federal Register on or about June 30 to reflect any changes in information.
(iii) A list of the names and mailing addresses of the governor's designees is available upon request from the Director, Office of State Programs, U.S. Nuclear Regulatory Commission, Washington, DC, 20555-0001.
(4) The licensee shall retain a copy of the notification as a record for three years.

CONTROL ROOM ACTIONS: None

ADDITIONAL RESPONSIBILITIES: The Radiation Protection Manager shall ensure that the appropriate notifications are made.

FOLLOWUP ACTIONS: None

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NONROUTINE REPORT - 20

TITLE: Lost or Unaccounted for Shipment of Spent Fuel or of SNM of Low or Moderate Strategic Significance.

FORMAT: Immediate Notification of the NRC Operations Center via the ENS within 1 hour after discovery of the loss and within 1 hour after recovery of or accounting for such lost shipment. Written followup report within 60 days.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR73.67(e)(3)

Each licensee who arranges for the in-transit physical protection of special nuclear material of moderate strategic significance, or who takes delivery of this material free on board (f.o.b.) the point at which it is delivered to a carrier for transport shall ... notify the NRC Operation Center within one hour after the discovery of the loss of or accounting for such lost shipment in accordance with the provisions of [10CFR] 73.71 of this part.

From 10CFR73.67(g)(3)

Each licensee, either shipper or receiver, who arranges for the physical protection of special nuclear material of low strategic significance while in transit or who takes delivery of such material free on board (f.o.b.) the point at which it is delivered to a carrier for transport shall ... notify the NRC Operations Center within one hour of the discovery of the loss of the shipment and within one hour after recovery of or accounting for such lost shipment in accordance with the provisions of [10CFR]73.71 of this part.

From 10CFR73.71(a)(1)

Each licensee ... shall notify the NRC Operations Center within one hour after discovery of the loss of any shipment of SNM or spent fuel and within one hour after recovery of or accounting for such lost shipment.

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NONROUTINE REPORT - 20

This notification must be made to the NRC Operations Center via the Emergency Notification System. If the Emergency Notification System is inoperative or unavailable, the licensee shall make the required notification via commercial telephone service or other dedicated telephone system or any other methods that will ensure that a report is received by the NRC Operations Center within one hour.

From 10CFR73.71(a)(4) & (5)

The initial telephonic notification must be followed within a period of 60 days by a written report submitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington, D.C. 20555.

Significant supplemental information which becomes available after the initial telephonic notification to the NRC Operations Center or after the submission of the written report must be telephonically reported to the NRC Operations Center and also submitted in a revised written report (with the revisions indicated) to the Regional Office and the Document Control Desk.

CONTENT: The report must include sufficient information for NRC analysis and evaluation.

ADDITIONAL INFORMATION: The licensee shall initiate immediately a trace investigation of any shipment of special nuclear material of low or moderate strategic significance that is determined to be lost or unaccounted for after a reasonable time beyond the estimated arrival time.

The Commercial telephone number of the NRC Operations Center is (301)-816-5100.

CONTROL ROOM ACTIONS: The Shift Manager shall notify the NRC within 1 hour after discovery of the loss of the shipment and within one hour after recovery of or accounting for such lost shipment and ensure that plant management is notified of the event.

FOLLOWUP ACTIONS: The Manager, Regulatory Affairs shall ensure the written followup report and any subsequent reports are prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 21

TITLE: Notification of Arrival - Special Nuclear Material of Moderate Strategic Significance

FORMAT: Notification by telephone to the Director of the NRC Region IV office within 24 hours after arrival of a shipment at its final destination or after such shipment has left the US as an export.

APPLICABILITY: CPNPP is subject to but currently unaffected by this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR73.67(e)(7)(ii)

The receiver of each shipment [of special nuclear material of moderate strategic significance], or the shipper if the receiver is not a licensee, shall notify the Administrator of the appropriate Nuclear Regulatory Commission Regional Office listed in Appendix A by telephone, no later than 24 hours after arrival of such shipment at its final destination, or after such shipment has left the United States as an export, to confirm the integrity of the shipment at the time of receipt or exit from the United States.

CONTENT: Pertinent factors of shipment, time, date and condition of shipment.

ADDITIONAL INFORMATION: None

CONTROL ROOM ACTIONS: None

FOLLOWUP ACTIONS: None

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NONROUTINE REPORT - 22

TITLE: Reportable Safeguards Events

FORMAT: Notification of the NRC Operation Center via the ENS within 1 hour of discovery of a reportable safeguards event.

Written followup report within 60 days.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR73.71(b)(1) & (2)

Each licensee ... shall notify the NRC Operations Center within one hour of discovery of the safeguards events described in Paragraph [I(a), I(b), I(c), and I(d)] of Appendix G to this part.

This notification must be made in accordance with the requirements of Paragraph (a)(2), (3), (4), and (5) of this section (See NONROUTINE REPORT-20).

From Appendix G to Part 73

Events to be reported within one hour of discovery, followed by a written report within 30 days.
(a) Any event in which there is reason to believe that a person has committed or caused, or attempted to commit or cause, or has made a credible threat to commit or cause:
(1) A theft or unlawful diversion of special nuclear material; or
(2) Significant physical damage to a power reactor or any facility possessing SSNM or its equipment or carrier equipment transporting nuclear fuel or spent nuclear fuel, or to the nuclear fuel or spent nuclear a facility or carrier possesses; or
(3) Interruption of normal operation of a licensed nuclear power reactor through the unauthorized use of or tampering with its machinery, components, or controls including the security system.

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NONROUTINE REPORT - 22

(b) An actual entry of an unauthorized person into a protected area, material access area, controlled access area, vital area, or transport.

(c) Any failure, degradation, or the discovered vulnerability in a safeguard system that could allow unauthorized or undetected access to a protected area, material access area, controlled access area, vital area, or transport for which compensatory measures have not been employed.

(d) The actual or attempted introduction of contraband into a protected area, material access area, vital area, or transport.

From 10CFR50.54(x) and (y)

(x) A licensee may take reasonable action that departs from a license condition or a technical specification (contained in a license issued under this part) in an emergency when this action is immediately needed to protect the public health and safety and no action consistent with license conditions and technical specifications that can provide adequate or equivalent protection is immediately apparent.

(y) Licensee action permitted by paragraph (x) of this section shall be approved, as a minimum, by a licensed senior operator, or, at a nuclear power reactor facility for which the certifications required under §§ 50.82(a)(1) have been submitted, by either a licensed senior operator or a certified fuel handler, prior to taking the action.

A severe weather event and/or condition that are not bounded by CPNPP Technical Specifications; 10CFR50.54(x) and (y) may be used to suspend security measures in an emergency when immediately necessary to protect the public health and safety and no other action can provide adequate or equivalent protection. Suspension of security measures in this case must be approved as a minimum by a licensed senior operator before taking action. For these events, the suspension of security measures must be reported and documented in accordance with the provisions of 10CFR73.71(b)(1). Note that per NUREG-1022 Rev.3, there is no report required per 10CFR50.54(x) for this condition (violation of a license condition). Only Technical Specification deviations authorized under 10CFR50.54(x) are reportable under this criterion.

CONTENT: Refer to Regulatory Guide 5.62 for contents of the 60-day followup written report.

ADDITIONAL INFORMATION: Any suspended security measures per this report shall be reinstated as soon as conditions permit.

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NONROUTINE REPORT - 22

CONTROL ROOM ACTIONS:

Typically, Security Management shall make the determination of the requirement for notification of the NRC and advise the Shift Manager if notification is required. Alternately, if Security Management is unable to make a timely the notification determination (within 30 minutes of discovery), the Operations Shift Manager will make the 1-hour report if Operations determines the event is reportable per this section of the procedure. The Shift Manager shall notify the NRC within 1 hour after discovery of a reportable safeguards event and ensure that plant management is notified of the event.

Message to Send: "Today, at _______ hours, Comanche Peak has experienced an event that concerns [enter Appx. G (a - d criteria) OR 50.54(x)] ____________________________________. There is a degradation in the ability of Security to implement the protective strategy or Security Plan Requirements. Current Security actions are as follows: __________________ ______________________________________. These actions shall be in effect pending further notification."

FOLLOWUP ACTIONS:

The Manager, Regulatory Affairs shall ensure the written followup report and any subsequent reports are prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 23

TITLE: Environmental Matters

FORMAT: Verbal notification and/or written notification to the appropriate state or federal agency.

Note that Environmental Services, Luminant Power should be notified as soon as possible for determining reportability and making the required reports.

REQUIREMENT: Reporting requirements are summarized below:

- Air emission upset
- Dangerous situation observed during dam inspection
- Fish die-off
- Oil and chemical spills
- Waste water discharge permit excursion in excess of the limits identified for "Additional Information" below.
- Ground water monitoring samples in excess of limits per the ground water monitoring plan

CONTENT: Refer to the *Quick Reference Guide for Environmental Matters*, Luminant Power, Environmental Division.

ADDITIONAL INFORMATION: Specifics are provided in the *Quick Reference Guide for Environmental Matters*, Luminant Power, Environmental Division.

The reporting week is considered to be from 0000 hours Sunday morning to 2359 hours the following Saturday.

When the following systems/components are initially operated anytime during the week, the Environmental Section shall obtain a sample for analysis:

- Circulating Water System
- Safe shutdown Impoundment 30" Make-up Valve
- Return flow to Lake Granbury
- Release of hazardous solid waste from a permitted Solid Waste Management Unit (SWMU) or the identification of an non-permitted SWMU in accordance with CPNPP RCRA part B permit

Upon notification by Environmental Services, Site Environmental shall notify the Shift Manager of State notifications.

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NONROUTINE REPORT - 23

Unusual fish kills and unanticipated or emergency discharges of wastewater or chemical substances are reportable to the NRC and TCEQ.

- Environmental limits for the once-through cooling water outfall are:

	Daily Average	Daily Maximum
Flow (MDG)	3168	
Free Available Chlorine	0.2 mg/1	0.5 mg/1
Total Residual Chlorine		0.2 mg/1
Temperature (degrees F)	113	116

Neither free available chlorine nor total residual chlorine may be discharged from any one unit for more than two hours in any one day. No discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

- Station Service Water discharges into the Safe Shutdown Impoundment (SSI) which in turn discharges into Squaw Creek Reservoir. The environmental limits for this discharge, intermittent flow from the SSI to Squaw Creek Reservoir are:

	Daily Average	Daily Maximum
Flow (MGD)	report estimate	report estimate
Total Suspended Solids	30 mg/1	100 mg/1
Oil and Grease	15 mg/1	20 mg/1

The pH is monitored once a week during discharge by grab sample. The pH shall not be less than 6.0 nor greater than 9.0. No discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

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NONROUTINE REPORT - 23

■ The environmental limits for Squaw Creek Reservoir discharge to Lake Granbury are:

	Daily Average	Daily Maximum
Flow (MGD)	23.9	23.9
Temperature (degrees F)	N/A	93
TDS	Report	4000 mg/1

No discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

■ Low volume wastewater and previously monitored effluents, into the Circulating Water discharge. This discharge also represents an alternate discharge for low volume waste pond effluent directly to Squaw Creek Reservoir. The limits for this discharge are:

	Daily Average	Daily Maximum
Flow (MGD)	Report Estimate	Report Estimate
Total Suspended Solids	30/1 100 mg/1	
Oil and Grease	15 mg/1	20 mg/1

pH shall not be less than 6.0 nor greater than 9.0. The pH shall be monitored once a week by grab sample. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

■ Metal Cleaning Waste:

	Daily Average	Daily Maximum
Iron total	1.0 mg/1	1.0 mg/1
Copper total	0.5 mg/1	1.0 mg/1

The pH, total suspended solids, oil and grease limits shall apply the Squaw Creek Reservoir discharge to Lake Granbury. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

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NONROUTINE REPORT - 23

pH shall not be less than 6.0 nor greater than 9.0. The pH shall be monitored once a week by grab sample. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil.

CONTROL ROOM ACTIONS: The Shift Manager shall notify the System Engineering Manager or designees of the environmental matter.

FOLLOWUP ACTIONS: The System Engineering Manager shall notify Corporate Environmental Services in accordance with the *Quick Reference Guide for Environmental Matters*, Luminant Power, Environmental Division.

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NONROUTINE REPORT - 24

TITLE: Technical Specification Report

FORMAT: Written report submitted within the time requirement of the Technical Specification (TS), Offsite Dose Calculation Manual (ODCM), or the Technical Requirements Manual (TRM).

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: Reporting requirements are specified in the following documents:

TS	TRM	ODCM
5.6.2 (Rad Oper Report)	13.10.32 (Gas Storage Tanks)	3.11.1.2(a)(Rad Effluents Dose)
5.6.3 (Rad Effluent)	13.10.33 (Explosive Gas)	3.11.2.2(a)(Noble Gases)
5.6.5 (COLR)		3.11.2.3(a)(Iodine/Tritium)
5.6.6 (PTLR)		3.11.4(a)Gases Radwaste)
5.6.9 (SG Tube Insp.)		

CONTENT: The content of each report is described in the associated section of the TS, ODCM, or TRM.

ADDITIONAL INFORMATION: 10CFR50.36 and NUREG 1022.

CONTROL ROOM ACTIONS: The Shift Manager shall ensure that a Condition Report is initiated in accordance with STA-421, and notify plant management of the event in accordance with management policy.

FOLLOWUP ACTIONS: The Manager, Regulatory Affairs shall ensure a report is prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 25

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NONROUTINE REPORT - 26

TITLE:	Oil/Gas Exploration/Drilling by Subsurface Mineral Rights Owners
FORMAT:	Notification of the NRC.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	From CPNPP Operating License Nos. NPF-87 and NPF-89, Condition 2.F(3) Luminant Generation Company, LLC shall promptly notify the NRC of any attempts by subsurface mineral rights owners to exercise mineral rights, including any legal proceeding initiated by mineral rights owner against Luminant Generation Company, LLC.
CONTENT:	Not specified.
ADDITIONAL INFORMATION:	Refer to FSAR Section 2.1.2, "Exclusion Area Authority and Control", and NUREG-0797, *Safety Evaluation Report Related to the Operation of CPSES Units* 1 and 2, July 1981, Section 2.1.2 for additional information. Paraphrased from SER Section 2.1.2 The applicant has proposed that ingress for mineral exploration would be permitted in the portions of the exclusion area only on the basis of written agreements between the applicant and the necessary parties. No ingress for mineral exploration will be allowed within that portion of the exclusive area which is within 2250 feet of a seismic category I building or within 2800 feet of either reactor containment building. Per discussion with the NRR Project Manager,“Exploration” is actual drilling for oil and gas and does not include subsurface mapping. When CPNPP becomes aware that exploration (drilling) is planned and scheduled, Luminant Power should prepare a letter to the NRC (Document Control Desk) to discuss the conditions of the agreement and schedule for drilling.

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NONROUTINE REPORT - 26

CONTROL ROOM ACTION: None

ADDITIONAL RESPONSIBILITIES: The Security Shift Supervisor shall notify Plant Management of an attempted site access.

The Manager, Regulatory Affairs shall ensure that the NRC is notified of any attempted access to the plant by subsurface mineral rights owners to exercise mineral rights or of any legal proceedings initiated by mineral rights owners.

FOLLOWUP ACTIONS: None

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NONROUTINE REPORT - 27

TITLE: Unusual or Important Environmental Event

FORMAT: Notification to NRC Region IV within 24 hours, Written followup report within 30 days.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: From Operating License Nos. NPF-87 and NPF-89, Appendix B, Environmental Protection Plan (EPP), Section 4.1

Any occurrence of an unusual or important event that indicates or could result in a significant environmental impact casually related to plant operation shall be recorded and reported to the NRC within 24 hours, followed by a written report per Subsection 5.4.2. The following are examples of such events: excessive bird impaction events, onsite plant or animal disease outbreaks, mortality or unusual occurrence of any species protected by the Endangered Species Act of 1973, fish kills, increase in nuisance organism or condition, and unanticipated or emergency discharge of waste water or chemical substances.

CONTENT: From EPP 5.4.2, Nonroutine Reports

A written report shall be submitted to the NRC within 30 days of occurrence of a nonroutine event. The report shall (a) describe, analyze, and evaluate the event, including extent and magnitude of the impact and plant operating characteristics; (b) describe the probable cause of the event; (c) indicate the action taken to correct the reported event; (d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems; and (e) indicate the agencies notified and their preliminary responses.

Events reportable under this subsection which also require reports to other Federal, State or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided with a copy of such a report at the same time it is submitted to the other agency.

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<u>NONROUTINE REPORT - 27</u>

ADDITIONAL INFORMATION: None

CONTROL ROOM ACTIONS: The Shift Manager should ensure that plant management is notified of the event.

FOLLOWUP ACTIONS: Plant Management should ensure that NRC is notified within 24 hours after the event.

The Manager, Environmental shall ensure the written report is prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 28

TITLE: Water Treatment Facility Outages

FORMAT: Written report in the form of a letter within 15 days after a determination that either routine or unplanned outages will exceed 30 consecutive days and when the groundwater pumpage rate will be greater than 30 gpm.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: From Operating License, Appendix B (EPP), Section 4.2.2

The following outages of the onsite water treatment facility shall be reported to the NRC:

(1) Routine or unplanned outages that exceed 30 consecutive days.
(2) Any outage of at least 24 hours duration, beginning with the third such outage in a calendar year, if these outages are accompanied by an increase in the monthly average groundwater pumpage to a rate exceeding 30 gpm. When it is determined that either routine or unplanned outages will exceed 30 consecutive days and when the groundwater pumpage rate will be greater than 30 gpm when averaged over the outage period, the licensee will prepare and submit a report to the NRC within 15 days after a determination of the extended outage is made.

CONTENT: From EPP 4.2.2

This report shall include (1) a discussion of the reason for the extended outage, (2) the expected duration of the outage, (3) an estimate of the date or the time required to return the onsite water treatment facility to operation, (4) a determination of the potential for lowering the groundwater levels in offsite wells, (5) an assessment of the impact of the projected groundwater level decline, and (6) a proposed course of action to mitigate any adverse effects.

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NONROUTINE REPORT - 28

ADDITIONAL INFORMATION: The basis for the CPNPP Operating License Condition is discussed in detail in NUREG-0775, Final Environmental Statement, Section 5.3.1.2. The primary concern of the reporting requirement is to ensure that the NRC is aware of conditions which may impact groundwater levels at CPNPP (i.e., extended Water Treatment Facility Outages involving the Reverse Osmosis Units and/or the Clarification Units).

CONTROL ROOM ACTIONS: None

FOLLOWUP ACTIONS: The System Engineering Manager shall ensure a written report is prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 29

TITLE: Inoperable Containment Dome Lights

FORMAT: Notification by telephone to the Federal Aviation Administration Flight Service at Meacham Field, Fort Worth, within 30 minutes.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: From FAA Clearance 76-SW-1433-0E Any extinguishment or improper functioning of any top steady burning lights on both units (if one light is available on one dome, a report to FAA is not required,) or any flashing obstruction light which will last more than 30 minutes should be immediately reported. Further notification to the FAA is not required. Refer to 47CFR17 for additional information.

CONTENT: The report should state the condition of the lights, the circumstances which caused the failure, and the probable date normal operation will be resumed.

ADDITIONAL INFORMATION: Containment Dome Height is 260 feet (1070'6" MSL)
Flight Service Station and FAA telephone numbers:

1-877-487-6867 (Primary)
1-817-541-3423 (Backup)

Site coordinates are as follows:

	Unit 1	Unit 2
Latitude	32° 17' 52.02"	32° 17' 54.85"
Longitude	97° 47' 06.15"	97° 47' 05.79"

The registration number for the Granbury airport is 1241856. FAA prefers that we use this number when reporting inoperable dome lights.

CONTROL ROOM ACTIONS: The Shift Manager shall notify the FAA of the inoperable dome lights. A report to the NRC pursuant to the requirements of 10CFR50.72(b)(2)(vi) is not required (reference NUREG-1022)

FOLLOWUP ACTIONS: The Shift Manager shall notify the FAA upon resumption of normal operation of the dome light.

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NONROUTINE REPORT - 31

TITLE: Accident to Nuclear Boiler

FORMAT: Immediate notification of the Chief Inspector by the most expeditious means available and apprise him of the nature of the accident.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: From Texas Department of Licensing and Regulation - Boiler Division, Title 16, Part 4, Chapter 65, Rule 65.100(j)(10) of the Texas Administrative Code

The owner or operator shall, in case of serious accidents to a nuclear boiler involving a breach of the pressure boundary integrity of components included in Exhibit 6, immediately notify the Chief Inspector by the most expeditious means available and appraise him of the nature of the accident. The Chief Inspector shall assess the nature of the accident, formulate the inspection activities as required and coordinate these activities with the owner or operator ~~user~~ and as necessary with other state and federal agencies having jurisdiction.

CONTENT: Appraise the Chief Inspector of the nature of the accident.

ADDITIONAL INFORMATION: Chief Inspector: Anthony Jones

Texas Department of Labor and Standards - Boiler Division
(512) 463-2904
(512) 475-2854 (fax machine)

CONTROL ROOM ACTIONS: The Shift Manager shall ensure that plant management is notified of the event.

ADDITIONAL RESPONSIBILITIES: Plant management shall ensure that the Chief Inspector is notified of the event.

FOLLOWUP ACTIONS: None

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NONROUTINE REPORT - 32

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NONROUTINE REPORT - 33

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NONROUTINE REPORT - 34

TITLE: Bankruptcy

FORMAT: Notification by immediate written report to the NRC Regional Administrator.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: 10 CFR 50.54(cc)

(1) Each licensee shall notify the appropriate NRC Regional Administrator, in writing, immediately following the filing of a voluntary or involuntary petition for bankruptcy under any chapter of title 11 (Bankruptcy) of the United States Code by or against:

- (i) The licensee;
- (ii) An entity (as that term is defined in 11 U.S.C. 101(14)) controlling the licensee or listing the license or licensee as property of the estate; or
- (iii) An affiliate (as that term is defined in 11 U.S.C. 101(2)) of the licensee.

(2) This notification must indicate:

- (i) The bankruptcy court in which the petition for bankruptcy was filed; and
- (ii) The date of the filing of the petition.

CONTENT: An immediate written report from CPNPP to the NRC Regional Administrator for Region IV. The report shall indicate if the report is a voluntary or involuntary petition for bankruptcy, the bankruptcy court in which the petition for bankruptcy was filed, and the date of the filing of the petition.

ADDITIONAL INFORMATION: The notification of bankruptcy requirements for special nuclear materials (i.e., 10 CFR 70.32(a)(9)) and independent storage of spent nuclear fuel (i.e., 10 CFR 72.44(b)(6)) are identical to the notification of bankruptcy requirements in 10 CFR 50.54(cc). The written notice should reference all three regulations.

CONTROL ROOM ACTIONS: None

ADDITIONAL RESPONSIBILITIES: Manager, Regulatory Affairs is responsible to prepare and submit the immediate written report.

FOLLOWUP ACTIONS: The Manager, Regulatory Affairs shall ensure that the written report is prepared and submitted in accordance with the applicable regulatory and procedural requirements.

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PAGE 1 OF 1

NONROUTINE REPORT - 35

TITLE:	Test Methods for Supplemental Fracture Toughness Tests
FORMAT:	Notification by written summary submitted to and approved by the Director, Nuclear Reactor Regulations prior to testing.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	This is a paraphrased summary only. Refer to source documents listed in Attachment 8.B. From 10CFR50, Appendix G, Section III.B Test methods for supplemental fracture toughness tests must be submitted to and approved by the Director, Office of Nuclear Reactor Regulation, prior to testing.
CONTENT:	None
ADDITIONAL INFORMATION:	None
CONTROL ROOM ACTIONS:	None
ADDITIONAL RESPONSIBILITIES:	None
FOLLOWUP ACTIONS:	The Manager, Technical Support shall ensure that the written supplemental report is prepared and submitted in accordance with the applicable regulatory and procedural requirements.

ATTACHMENT 8.D/36
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NONROUTINE REPORT -36

TITLE:	Update of Projected Values for Reference Temperature for Pressurized Thermal Shock for Reactor Vessel Beltline Materials
FORMAT:	Notification by written summary submitted to the NRC following a significant change in projected values.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	This is a paraphrased summary only. Refer to source documents listed in Attachment 8.B. From 10CFR50.61(b)(1) ...Submittals must be updated whenever there is a significant change in projected values of RT_{PTS}...
CONTENT:	None
ADDITIONAL INFORMATION:	None
CONTROL ROOM ACTION:	None
ADDITIONAL RESPONSIBILITIES:	None
FOLLOWUP ACTIONS:	The Manager, Technical Support shall ensure that the written supplemental report is prepared and submitted in accordance with the applicable regulatory and procedural requirements.

ATTACHMENT 8.D/37
PAGE 1 OF 1

NONROUTINE REPORT - 37

TITLE: Application for Use of Respiratory Protection Equipment That Has Not been Tested or Certified by NIOSH/MSHA

FORMAT: Written application submitted to the NRC for authorized use of that equipment.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10CFR20.1703(a)(2)

If the licensee wishes to use equipment that has not been tested or certified by NIOSH/MSHA, or for which there is no schedule for testing or certification, the licensee shall submit an application for authorized use of that equipment, including a demonstration by testing, or a demonstration based on reliable test information, that the material and performance characteristics of the equipment are capable of providing the proposed degree of protection under anticipated conditions of use.

CONTENT: None

ADDITIONAL INFORMATION: None

CONTROL ROOM ACTIONS: None

ADDITIONAL RESPONSIBILITIES: Radiation Protection Manager shall ensure that the application is prepared and submitted in accordance with applicable regulatory and procedural requirements.

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NONROUTINE REPORT - 38

TITLE:	Analytical Evaluations of Exam Results as Required by IWB/IWC 3132.4
FORMAT:	Notification in written summary to the NRC as promptly as practical.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	ASME Section XI, IWB-3134(b) and IWC-3134(b)
CONTENT:	None
ADDITIONAL INFORMATION:	None
CONTROL ROOM ACTIONS:	None
ADDITIONAL RESPONSIBILITIES:	None
FOLLOWUP ACTIONS:	The Manager, Technical Support shall ensure that the written report is prepared and submitted in accordance with applicable regulatory and procedural requirements.

ATTACHMENT 8.D/39
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NONROUTINE REPORT - 39

TITLE: Overflights or Sightings of Aircraft in the Vicinity of CPNPP

FORMAT: Prompt notification to NRC, FAA, FBI and Somervell County Sheriff office by telephone and written Security Field Report (SFR) and logged by Security as promptly as practical if the event meets reporting requirements below.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B and as identified in the table associated with this report.
14CFR99.7 - Air Directives and Notice to Airmen (AD/NOTAM) for those aircraft operating in Air Route Traffic Control Center (ARTCC) NOTAMS - KZFW (DFW area (et. all.))

FDC 1/3352 - [Stated in Part] Special Notice . . . Flight restrictions effective immediately until further notice, pursuant to 14CFR99.7, Special Security Instructions, operations within the territorial airspace of the U.S.. This is a restatement of a previous advisory. Pilots are advised to avoid the airspace above or in proximity to sites such as nuclear power plants . . . . Pilots should not circle as to loiter in the vicinity of such facilities.

CONTENT: Telephonic: -
As promptly as possible not to extend beyond one hour for reportable events (see notes for table below).
Courtesy call to the NRC Operations Center required for loggable events (see notes for table below).
As applicable from Attachment 8.A
If flight was expected (Y,N)
Description of Air Vehicle (type, number of engines, color, markings)
Direction and/or Pattern of Travel
General (weather conditions, time of day, number of observers)

ATTACHMENT 8.D/39
PAGE 2 OF 6

NONROUTINE REPORT - 39

Written Report:
As noted above for telephonic information, and
As required on SFR form

ADDITIONAL INFORMATION:

Clarification and agreement between NRC Region IV Security Office and Regulatory Affairs for the application of 'loggable'/'reportable' was determined to affect aircraft activities within a 2 nautical mile radius of the facility (as measured from the containment structures). This range based on 3 criteria:

1. The initial advisory was a 10 mile radius and then reduced to 3 mile operation around the structures identified above - later the mile restriction was lifted,
2. The OCA for this facility is 2 nautical miles in diameter (approximate average), and
3. Other standing FAA advisories that affect nuclear power plants, restricts overflights or loitering around certain structures and/or functions to a distance of a 3 nautical mile radius.

Notification to the Federal Aviation Administration (FAA) and/or the Federal Bureau of Investigation (FBI) may be necessary for events associated with air vehicles (e.g., aircraft, parachutes, balloons) as they are associated with potential violations or deviation from current ICM, special RIS or other regulatory requirement(s) associated with elevated security levels. In addition to telephone notifications as indicated in 6.2.2 and 6.2.3, the following telephone numbers are available for making notifications for events and conditions requiring notification:

FAA (24 hours)	(817) 858-7503
FAA Backup	(817) 858-7504
FBI (Days M-F)	(254) 772-1627 [Ask for Mr. J. Truhitt or Mr. L. Ledger]
FBI Backup	(210) 225-6741 [Ask for "Terrorist Supervisor"]
Somervell County Sheriff	(254) 897-2242

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NONROUTINE REPORT - 39

CONTROL ROOM ACTIONS: For reportable conditions, in addition to telephone notifications as indicated in 6.2.2 and 6.2.3, the telephone numbers noted above are available for making notifications for events and conditions requiring notification:

ADDITIONAL RESPONSIBILITIES: For events which are considered an event that is driven by violation, incursion or deviation from current ICM, special Regulatory Information Summary (RIS) or other regulatory requirement(s) associated with elevated security levels as identified by the NRC or Office of Homeland Security; appropriate actions shall be implemented and controlled via facility Security and Emergency plans.

FOLLOWUP ACTIONS: The Security Manager shall ensure that the written report is prepared and submitted in accordance with applicable procedural requirements and as requested by external agencies. If the event requires implementation of any of the Security Plans, the Security Manager will coordinate as required by Security and Emergency Plan requirements.

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NONROUTINE REPORT - 39

Reporting Table
Air Vehicle Activity Affecting Nuclear Power Plants

Event Type	**IF**	**Logic Application**	**THEN**	**Reporting Requirements**
Deminimus Event 1	Air vehicle passes within the OCA (2 nautical mile radius from containment)	**AND is above** 500 feet **AND does not** circle, loiter or perform other air maneuvers suggesting an 'interest' in the facility.	No Required Action	No Reporting Requirements
Deminimus Event 2	Pipeline/ Transmission line flyover flight is planned and scheduled	**AND** pilot called ahead to assure CPNPP knows it will occur.	No Required Action	No Reporting Requirements
Loggable Event 1	If the flight seems to be lower than 500 feet within the OCA **OR** closer than 1000 feet to a facility structure	**AND** is **less than 3 minutes** in duration **AND** **no** outward threatening action by the aircraft was noted.	[a] log the event in the Security Event Log [b] complete the SFR	[a] complete notifications per the SFR ***[note 1]*** , ***[note 2]*** **AND** [b] Control Room make a prompt courtesy call to the NRC Ops Center ***[note 2]*** **AND** [c] Generate a CR. ***Note***: The call to the NRC is a courtesy call only. ***[note 1]***
Loggable Event 2	If the pipeline flyover flight is **not** done on its regular schedule **OR** occurs without prior notification	None	[a] log the event in the Security Event Log **AND** [b] call aircraft flight operations to confirm flight plan	No Reporting Requirements

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NONROUTINE REPORT - 39

Reporting Table
Air Vehicle Activity Affecting Nuclear Power Plants (Cont'd)

Event Type	IF	Logic Application	THEN	Reporting Requirements
Reportable Event 1	If the vehicle performs outwardly potentially threatening actions or functions*, **OR** continues to loiter, circle or other functions*, **OR** reduces altitude to below 500 feet within the OCA *reduces speed, dives, performs aerobatics, very low flight levels	**Immediately** for **more than 3 minutes** for **more than 3 minutes**	[a] log the event in the Security Event Log **AND** [b] take actions as identified in next column **AND** [c] implementation of the PSP and EP should be evaluated	[a] Complete the SFR **AND** [b] Complete notifications per the SFR **AND** [c] Control Room to make a 1 hour reportability call to the NRC Ops Center **AND** complete a NRC-361 form **AND** [d] Generate a CR.
Reportable Event 2	An aircraft lands or crashes into Squaw Creek Reservoir **OR** lands within the OCA without prior notification and clearance from the FAA.	**Immediately** **Immediately**	[a] log the event in the Security Event Log **AND** [b] take actions as identified in next column **AND** [c] implementation of the PSP and EP should be evaluated	[a] Complete the SFR **AND** [b] Complete notifications per the SFR **AND** [c] Control Room to make a 1 hour reportability call to the NRC Ops Center and complete a NRC-361 form **AND** [d] Generate a CR.

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NONROUTINE REPORT - 39

Reporting Table
Air Vehicle Activity Affecting Nuclear Power Plants (Cont'd)

[Note 1] Notifications per the Security Field Report (SFR) are the FAA, Sheriff Department (Somervell), FBI and others as determined by the Control Room. Notifications Required per FAA NOTAM 1/3352, et. al., 14CFR99.7, "Special Security Instructions" and NRC-Regulatory Information Summary (RIS) requirements for notification of air vehicle fly over activity. Under loggable conditions, notification to the NRC Operations Center is considered a courtesy call only.

[Note 2] Per NRC (RIV/DRS) on 12/29/03, CareFlight (medical evacuation) helicopter flight crossing the OCA **AND** below 500 feet shall be called into the FAA per instructions on the SFR form, however, notification to the NRC **IS NOT** required.

[Note 3] In reference to NRC IA-14-03 concerning the operation of Unmanned Aerial Systems (UAS) near CPNPP, all reporting requirements noted in NR-39 apply. The Security Manager should exercise judgment/discretion in the determinant determination of whether the flight activity is suspicious and if the event should be voluntarily reported to the NRC in accordance with guidance in NRC IA-14-03.

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NONROUTINE REPORT - 40

TITLE: Suspension of Security Measures due to Inclement Weather at CPNPP

FORMAT: Notify the NRC Operations Center and Region IV offices by telephone within one hour, generate a Security Field Report (SFR)/Condition Report, and Security log entry as promptly as practical to meet the reporting requirements below.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: CPNPP Security Plan, Section 24.3.
10CFR73.71 and 10CFR73.55(p)

10CFR73.55(p) addresses suspension of security measures and allows the licensee to suspend measures under the following conditions:

• 10CFR73.55(p)(1)(ii) allows for suspending security measures during severe weather when immediately needed to protect the health and safety of security force personnel and no other action can provide adequate or equivalent protection. This must be approved as a minimum by a licensed senior operator with input from the security supervisor or manager before taking these actions. Compensatory actions are performed in accordance with the CPNPP Security Plan. These events must be reported and documented in accordance with 10CFR73.71(c).

• Suspended security measures per this report are to be reinstated as soon as conditions permit.

• **IF** the event progresses to include degradation of security systems or a severe weather event and/or condition **that are not bounded** by CPNPP Technical Specifications [10CFR50.54(x) &10CFR50.54(y)]; promptly evaluate conditions per NR-22 and take actions as identified.

Although the suspension of security requirements may be performed and is addressed in 10 CFR 50.54(x) and (y), compensatory actions will normally be performed in accordance with the CPNPP Security Plan.

CONTENT: Telephonic:
• Within one (1) hour, a notification call to the NRC Operations Center is required.

• As soon as practical notify the Region IV Office.

• Upon restoration of suspended security measures, the NRC Operations Center and the Region IV Office shall be notified as soon as practical.

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NONROUTINE REPORT - 40

ADDITIONAL INFORMATION: A telephone call shall be placed to the NRC Region IV office using the following numbers in conjunction with the required NRC Operations center notification:

Region IV General Number	(817) 860-8100
Region IV Toll Free	(800) 952-9677

CONTROL ROOM ACTIONS: Completed within one (1) hour telephonic notification to the NRC Operations center but as soon as practical. Notify the NRC Region IV office as soon as practical (see telephone numbers identified in ADDITIONAL INFORMATION above) from 6:00am and 6:00pm.

Coordinate with Security to assess conditions and provide concurrence and approval for suspending security measures prior to calling the NRC Operations Center. Information sent to the NRC is noted on the "Suspension of Security Measures due to Inclement Weather" SFR.

For a 10CFR73.55(p)(ii) Event, Message to Send: "At _______ hours, Comanche Peak has suspended security measure(s) [*read SFR*] due to inclement weather in accordance with the Security Plan. No degradation in the ability of Security to implement the protective strategy or Security Plan Requirements has been identified. This suspension shall be in effect pending further notification."

ADDITIONAL RESPONSIBILITIES: Upon approval by, at a minimum, the licensed senior operator, the security supervisor or manager may begin suspension of identified security measures. Appropriate actions shall be implemented and controlled via facility Security and Emergency plans.

FOLLOWUP ACTIONS: The Security Manager shall ensure that a SFR and Condition Report are issued and the event has been logged. Upon event closeout, the Security Manager shall ensure that the Operations Center and the NRC Region IV office are telephonically notified by Operations.

ATTACHMENT 8.D/41
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NONROUTINE REPORT - 41

TITLE: ERCOT/NERC/DOE Reports

FORMAT: The Control Room shall notify the QSE, Meter & Relay, and Oncor as soon as practicable by telephone as required below.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: Luminant Corporate Procedures G-3025 and G-3035.

Luminant Power Control Room personnel shall report the occurrence of any of the following conditions to the QSE as soon as practicable after the condition becomes known:

1. Total generation loss, within one minute, of ≥ 1,000 MW in the ERCOT Interconnection [i.e., a reactor trip].
2. Damage or destruction of its Facility that results from actual or suspected intentional human action; or
3. Physical threat to its Facility, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility; or
4. Suspicious device or activity at a facility. Do not report theft unless it degrades normal operation of a Facility.

NOTE:	Examples of the reportable events above, include, but are not limited to, bombing a facility, setting fire to a facility, loosening bolts or tampering with equipment settings in order to damage a facility or equipment, the unauthorized entry into a company computer system, or taking photographs of a facility with the intent of planning a sabotage event.

5. Failure to Trip During Fault - Any failure of a Protection System to operate for a Fault within the zone it is designed to protect. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct;
6. Failure to Trip Other than Fault - A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct;
7. Slow Trip During Fault – A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect;
8. Slow Trip Other than Fault - A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate;
9. Unnecessary Trip During a Fault - Any unnecessary Protection System operation for a Fault not within the zone of protection;
10. Unnecessary Trip Other Than Fault – Any unnecessary Protection System operation when no fault or other abnormal condition has occurred;

ATTACHMENT 8.D/41
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NONROUTINE REPORT - 41

CONTENT:	Control Room provides information as requested by the QSE and Oncor.
ADDITIONAL INFORMATION:	Luminant Energy serves as the QSE for CPNPP.
CONTROL ROOM ACTIONS:	The Control Room shall notify the QSE at 214-875-9778 as soon as practicable for items 1 through 10. The Control Room shall notify Oncor at 214-743-6920/6921 as soon as practicable for items 5 through 10 per Att. 2 of IPO-009A/B. The Control Room shall notify Meter & Relay of a potential NERC relay Misoperation for items 5 through 10 per Att. 2 of IPO-009A/B.
METER & RELAY ACTIONS:	For items 5 through 10 above (other than reverse power relay activation), Meter & Relay shall investigate all relay activations and determine if a relay misoperation occurred. If a misoperation occurred, they shall contact the Control Room as soon as it is known. Document the relay misoperation on the TRE Misoperation Summary Form, Attachment A of G-3035. Include the cause of the misoperation and a mitigation plan to prevent future occurrences of a similar nature. Provide the relay misoperation documentation to Regulatory and Market Support (RMS) within 10 business days of identifying the relay misoperation.
FOLLOWUP ACTIONS:	The following documentation will be provided to QSE concerning a misoperation event: CPNPP Operator Logs of communication related to the relay misoperation, copies of emails related to the relay misoperation submittals to regulatory agencies, copies of relay investigation forms, QSE Dispatcher Logs of communication related to relay misoperation, copies of applicable relay misoperation mitigation or Corrective Action Plan documentation, and digital fault recorder (DFR) documentation needed for relay misoperation investigations.

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NONROUTINE REPORT - 42

TITLE: Nationally Tracked Sources

FORMAT: Manufacture, transfer, receipt, disassembly, or disposal of a nationally tracked source requires completion and submittal a National Source Tracking Transaction Report as specified in 10CFR20.2207 paragraphs (a) through (e) for each type of transaction.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: From 10CFR20.2207(a): Each licensee who manufactures a nationally tracked source shall complete and submit a National Source Tracking Transaction Report. The report must include the following information:

(1) The name, address, and license number of the reporting licensee;

(2) The name of the individual preparing the report;

(3) The manufacturer, model, and serial number of the source;

(4) The radioactive material in the source;

(5) The initial source strength in becquerels (curies) at the time of manufacture

(6) The manufacture date of the source.

From 10CFR20.2207(b): Each licensee that transfers a nationally tracked source to another person shall complete and submit a National Source Tracking Transaction Report. The report must include the following information:

(1) The name, address, and license number of the reporting licensee;

(2) The name of the individual preparing the report;

(3) The name and license number of the recipient facility and the shipping address;

(4) The manufacturer, model, and serial number of the source or, if not available, other information to uniquely identify the source;

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NONROUTINE REPORT - 42

(5) The radioactive material in the source;

(6) The initial or current source strength in becquerels (curies);

(7) The date for which the source strength is reported;

(8) The shipping date;

(9) The estimated arrival date; and

(10) For nationally tracked sources transferred as waste under a Uniform Low-Level Radioactive Waste Manifest, the waste manifest number and the container identification of the container with the nationally tracked source.

From 10CFR20.2207(c): Each licensee that receives a nationally tracked source shall complete and submit a National Source Tracking Transaction Report. The report must include the following information:

(1) The name, address, and license number of the reporting licensee;

(2) The name of the individual preparing the report;

(3) The name, address, and license number of the person that provided the source;

(4) The manufacturer, model, and serial number of the source or, if not available, other information to uniquely identify the source;

(5) The radioactive material in the source;

(6) The initial or current source strength in becquerels (curies);

(7) The date for which the source strength is reported;

(8) The date of receipt; and

(9) For material received under a Uniform Low-Level Radioactive Waste Manifest, the waste manifest number and the container identification with the nationally tracked source.

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NONROUTINE REPORT - 42

From 10CFR20.2207(d): Each licensee that disassembles a nationally tracked source shall complete and submit a National Source Tracking Transaction Report. The report must include the following information:

(1) The name, address, and license number of the reporting licensee;

(2) The name of the individual preparing the report;

(3) The manufacturer, model, and serial number of the source or, if not available, other information to uniquely identify the source;

(4) The radioactive material in the source;

(5) The initial or current source strength in becquerels (curies);

(6) The date for which the source strength is reported;

(7) The disassemble date of the source.

From 10CFR20.2207(e): Each licensee who disposes of a nationally tracked source shall complete and submit a National Source Tracking Transaction Report. The report must include the following information:

(1) The name, address, and license number of the reporting licensee;

(2) The name of the individual preparing the report;

(3) The waste manifest number;

(4) The container identification with the nationally tracked source.

(5) The date of disposal; and

(6) The method of disposal.

NONROUTINE REPORT - 42

From 10CFR20.2207(f): The reports discussed in paragraphs (a) through (e) of this section must be submitted by the close of the next business day after the transaction. A single report may be submitted for multiple sources and transactions. The reports must be submitted to the National Source Tracking System by using:

(1) The on-line National Source Tracking System;

(2) Electronically using a computer readable format;

(3) By facsimile;

(4) By mail to the address on the National Source Tracking Transaction Report Form (NRC Form 748); or

(5) By telephone with follow-up by facsimile or mail.

From 10CFR20.2207(g): Each licensee shall correct any error in previously filed reports or file a new report for any missed transaction within 5 business days of the discovery of the error or missed transaction. Such errors may be detected by a variety of methods such as administrative reviews or by physical inventories required by regulation.

CONTENT: See content descriptions for 10CFR20.2207(a) thru (g) above.

ADDITIONAL INFORMATION: None.

CONTROL ROOM ACTIONS: None.

FOLLOWUP ACTIONS: None.

ADDITIONAL RESPONSIBILITIES: Radiation Protection Manager shall ensure that these reports are prepared and submitted in accordance with applicable regulatory and procedural requirements.

ATTACHMENT 8.D/43
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NONROUTINE REPORT - 43

TITLE:	ERCOT Restricted Systems suspected access violation.
FORMAT:	Verbal and e-mail notification.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	Reporting requirements are specified in the following document: STA-913, Attachment 8.C.
CONTENT:	Refer to STA-913, Attachment 8.C.
ADDITIONAL INFORMATION:	ERCOT Protocol 16.14.
CONTROL ROOM ACTIONS:	None.
FOLLOWUP ACTIONS:	The Cyber Security Program Manager shall provide verbal and e-mail notifications to the designated Luminant Generation Compliance contacts below upon notification of a suspected ERCOT Restricted System access violation per STA-913, Attachment 8.C, with a copy to the Manager, Regulatory Affairs.

Email Address/Phone Number
Rick.Terrill@Luminant.com
214-875-8750
Duane.Steward@Luminant.com
214-875-8726
Bobby.Crump@Luminant.com
214-875-8745

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NONROUTINE REPORT – 44

TITLE:	Dry Storage Cask Fuel Misloading
FORMAT:	Notification to the NRC Operations Center by telephone and a follow-up written special report.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	HI-STORM 100 Certificate of Compliance, Appendix B, Section 2.2 If any Fuel Specifications or Loading Conditions of CoC Appendix B, Section 2.1 are violated, the affected fuel assemblies shall be placed in a safe condition and the NRC shall be notified.
CONTENT:	Telephonic: Content as requested during notification.
ADDITIONAL INFORMATION:	NRC Operations Center telephone number: (301) 816-5100.
CONTROL ROOM ACTIONS:	Telephone notification is to be completed as soon as practical but within 24 hours to the NRC Operations Center.
FOLLOWUP ACTIONS:	Submit a special report which describes the cause of the violation, and action taken to restore compliance and prevent recurrence within 30 days.

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NONROUTINE REPORT – 45

TITLE: Departure from a CoC/TS Condition

FORMAT: Notification to the NRC Operations Center by telephone and a follow-up written special report.

APPLICABILITY: CPNPP is subject to this reporting requirement

REQUIREMENT: 10 CFR 72.75(b)(1):

An action taken in an emergency that departs from a condition or a technical specification contained in a 10 CFR 72 license or certificate of compliance when the action is immediately needed to protect the public health and safety, and no action consistent with license or certificate of compliance conditions or technical specifications that can provide adequate or equivalent protection is immediately apparent.

CONTENT: Telephonic:
Content per Attachment 8.A, Section II.

ADDITIONAL INFORMATION: NRC Operations Center telephone number: (301) 816-5100.

CONTROL ROOM ACTIONS: Telephone notification is to be completed as soon as practical but within 4 hours to the NRC Operations Center.

FOLLOWUP ACTIONS: Notifications during the course of the event per10 CFR 72.75(f):

1. Immediately report any further degradation in the level of safety of the ISFSI or other worsening conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made; or any change from one Emergency Class to another; or a termination of the Emergency Class.

2. Immediately report the results of ensuing evaluations or assessments of ISFSI conditions; the effectiveness of response or protective measures taken; and information related to ISFSI behavior that is not understood.

3. Maintain an open, continuous communication channel with the NRC Headquarters Operations Center upon request by the NRC.

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Written report per 10 CFR 72.75(g):

Submit a written follow-up report to the Commission within 60 days of the initial notification. Written reports prepared pursuant to other regulations may be submitted to fulfill this requirement if the reports contain all the necessary information and the appropriate distribution is made. These written reports must be of sufficient quality to permit legible reproduction and optical scanning and must be submitted to the NRC in accordance with 10 CFR 72.4. These reports must include the following information:

(1) A brief abstract describing the major occurrences during the event, including all component or system failures that contributed to the event and significant corrective action taken or planned to prevent recurrence;

(2) A clear, specific, narrative description of the event that occurred so that knowledgeable readers conversant with the design of an ISFSI or MRS, but not familiar with the details of a particular facility, can understand the complete event. The narrative description must include the following specific information as appropriate for the particular event:
(i) The ISFSI or MRS operating conditions before the event;
(ii) The status of structures, components, or systems that were inoperable at the start of the event and that contributed to the event;
(iii) The dates and approximate times of occurrences;
(iv) The cause of each component or system failure or personnel error, if known;
(v) The failure mode, mechanism, and effect of each failed component, if known;
(vi) A list of systems or secondary functions that were also affected for failures of components with multiple functions;
(vii) For wet spent fuel storage systems only, after the failure that rendered a train of a safety system inoperable, an estimate of the elapsed time from the discovery of the failure until the train was returned to service;
(viii) The method of discovery of each component or system failure or procedural error;
(ix) For each human performance related root cause, the licensee shall discuss the cause(s) and circumstances;
(x) For wet spent fuel storage systems only, any automatically and manually initiated safety system responses;
(xi) The manufacturer and model number (or other identification) of each component that failed during the event; and
(xii) The quantities and chemical and physical forms of the spent fuel, HLW, or reactor-related GTCC waste involved in the event;

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(3) An assessment of the safety consequences and implications of the event. This assessment must include the availability of other systems or components that could have performed the same function as the components and systems that failed during the event;

(4) A description of any corrective actions planned as a result of the event, including those to reduce the probability of similar events occurring in the future;

(5) Reference to any previous similar events at the same facility that are known to the licensee;

(6) The name and telephone number of a person within the licensee's organization who is knowledgeable about the event and can provide additional information concerning the event and the facility's characteristics; and

(7) The extent of exposure of individuals to radiation or to radioactive materials without identification of individuals by name.

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NONROUTINE REPORT – 46

TITLE: Event-related News Release or Notification of Other Government Agency

FORMAT: Notification to the NRC Operations Center by telephone

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: 10 CFR 72.75(b)(2):

Any event or situation related to the health and safety of the public or onsite personnel, or protection of the environment, for which a news release is planned or notification to other Government agencies has been or will be made. Such an event may include an onsite fatality or inadvertent release of radioactively contaminated materials.

CONTENT: Telephonic:
Content per Attachment 8.A, Section II.

ADDITIONAL INFORMATION:

NRC Operations Center telephone number: (301) 816-5100. The NRC should be notified within 4 hours of whichever of the following occurs first: 1) a plan to report to either the press or another government agency is approved by an individual authorized to make the final decision or 2) a report has actually been made to the press or another government agency. For a press release, the ENS notification should be completed before issuing the press release because news media representatives usually contact the NRC public affairs officer shortly after its issuance for verification, explanation, or interpretation of the facts.

CONTROL ROOM ACTIONS:

Telephone notification is to be completed as soon as practical but within 4 hours to the NRC Operations Center.

FOLLOWUP ACTIONS:

Notifications during the course of the event per10 CFR 72.75(f):

1. Immediately report any further degradation in the level of safety of the ISFSI or other worsening conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made; or any change from one Emergency Class to another; or a termination of the Emergency Class.

2. Immediately report the results of ensuing evaluations or assessments of ISFSI conditions; the effectiveness of response or protective measures taken; and information related to ISFSI behavior that is not understood.

3. Maintain an open, continuous communication channel with the NRC Headquarters Operations Center upon request by the NRC.

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NONROUTINE REPORT – 47

TITLE:	Defect in Storage System SSC Important to Safety
FORMAT:	Notification to the NRC Operations Center by telephone
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	10 CFR 72.75(c)(1): A defect in any spent fuel, HLW, or reactor-related GTCC waste storage structure, system, or component that is important to safety.
CONTENT:	Telephonic: Content per Attachment 8.A, Section II.
ADDITIONAL INFORMATION:	NRC Operations Center telephone number: (301) 816-5100.
CONTROL ROOM ACTIONS:	Telephone notification is to be completed as soon as practical but within 8 hours to the NRC Operations Center.
FOLLOWUP ACTIONS:	Notifications during the course of the event per10 CFR 72.75(f):

1. Immediately report any further degradation in the level of safety of the ISFSI or other worsening conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made; or any change from one Emergency Class to another; or a termination of the Emergency Class.

2. Immediately report the results of ensuing evaluations or assessments of ISFSI conditions; the effectiveness of response or protective measures taken; and information related to ISFSI behavior that is not understood.

3. Maintain an open, continuous communication channel with the NRC Headquarters Operations Center upon request by the NRC.

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NONROUTINE REPORT – 47

Written report per 10 CFR 72.75(g):

Submit a written follow-up report to the Commission within 60 days of the initial notification. Written reports prepared pursuant to other regulations may be submitted to fulfill this requirement if the reports contain all the necessary information and the appropriate distribution is made. These written reports must be of sufficient quality to permit legible reproduction and optical scanning and must be submitted to the NRC in accordance with 10 CFR 72.4. These reports must include the following information:

(1) A brief abstract describing the major occurrences during the event, including all component or system failures that contributed to the event and significant corrective action taken or planned to prevent recurrence;

(2) A clear, specific, narrative description of the event that occurred so that knowledgeable readers conversant with the design of an ISFSI or MRS, but not familiar with the details of a particular facility, can understand the complete event. The narrative description must include the following specific information as appropriate for the particular event:
(i) The ISFSI or MRS operating conditions before the event;
(ii) The status of structures, components, or systems that were inoperable at the start of the event and that contributed to the event;
(iii) The dates and approximate times of occurrences;
(iv) The cause of each component or system failure or personnel error, if known;
(v) The failure mode, mechanism, and effect of each failed component, if known;
(vi) A list of systems or secondary functions that were also affected for failures of components with multiple functions;
(vii) For wet spent fuel storage systems only, after the failure that rendered a train of a safety system inoperable, an estimate of the elapsed time from the discovery of the failure until the train was returned to service;
(viii) The method of discovery of each component or system failure or procedural error;
(ix) For each human performance related root cause, the licensee shall discuss the cause(s) and circumstances;
(x) For wet spent fuel storage systems only, any automatically and manually initiated safety system responses;
(xi) The manufacturer and model number (or other identification) of each component that failed during the event; and
(xii) The quantities and chemical and physical forms of the spent fuel, HLW, or reactor-related GTCC waste involved in the event;

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NONROUTINE REPORT – 47

(3) An assessment of the safety consequences and implications of the event. This assessment must include the availability of other systems or components that could have performed the same function as the components and systems that failed during the event;

(4) A description of any corrective actions planned as a result of the event, including those to reduce the probability of similar events occurring in the future;

(5) Reference to any previous similar events at the same facility that are known to the licensee;

(6) The name and telephone number of a person within the licensee's organization who is knowledgeable about the event and can provide additional information concerning the event and the facility's characteristics; and

(7) The extent of exposure of individuals to radiation or to radioactive materials without identification of individuals by name.

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NONROUTINE REPORT – 48

TITLE: Reduction in Effectiveness of Waste Storage Confinement System during Use

FORMAT: Notification to the NRC Operations Center by telephone and a follow-up written special report.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: 10 CFR 72.75(c)(2):

A significant reduction in the effectiveness of any spent fuel, HLW, or reactor-related GTCC waste storage confinement system during use.

CONTENT: Telephonic:
Content per Attachment 8.A, Section II.

ADDITIONAL INFORMATION: NRC Operations Center telephone number: (301) 816-5100.

CONTROL ROOM ACTIONS: Telephone notification is to be completed as soon as practical but within 8 hours to the NRC Operations Center.

FOLLOWUP ACTIONS: Notifications during the course of the event per10 CFR 72.75(f):

1. Immediately report any further degradation in the level of safety of the ISFSI or other worsening conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made; or any change from one Emergency Class to another; or a termination of the Emergency Class.

2. Immediately report the results of ensuing evaluations or assessments of ISFSI conditions; the effectiveness of response or protective measures taken; and information related to ISFSI behavior that is not understood.

3. Maintain an open, continuous communication channel with the NRC Headquarters Operations Center upon request by the NRC.

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NONROUTINE REPORT – 48

Written report per 10 CFR 72.75(g):

Submit a written follow-up report to the Commission within 60 days of the initial notification. Written reports prepared pursuant to other regulations may be submitted to fulfill this requirement if the reports contain all the necessary information and the appropriate distribution is made. These written reports must be of sufficient quality to permit legible reproduction and optical scanning and must be submitted to the NRC in accordance with 10 CFR 72.4. These reports must include the following information:

(1) A brief abstract describing the major occurrences during the event, including all component or system failures that contributed to the event and significant corrective action taken or planned to prevent recurrence;

(2) A clear, specific, narrative description of the event that occurred so that knowledgeable readers conversant with the design of an ISFSI or MRS, but not familiar with the details of a particular facility, can understand the complete event. The narrative description must include the following specific information as appropriate for the particular event:
(i) The ISFSI or MRS operating conditions before the event;
(ii) The status of structures, components, or systems that were inoperable at the start of the event and that contributed to the event;
(iii) The dates and approximate times of occurrences;
(iv) The cause of each component or system failure or personnel error, if known;
(v) The failure mode, mechanism, and effect of each failed component, if known;
(vi) A list of systems or secondary functions that were also affected for failures of components with multiple functions;
(vii) For wet spent fuel storage systems only, after the failure that rendered a train of a safety system inoperable, an estimate of the elapsed time from the discovery of the failure until the train was returned to service;
(viii) The method of discovery of each component or system failure or procedural error;

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NONROUTINE REPORT – 48

(ix) For each human performance related root cause, the licensee shall discuss the cause(s) and circumstances;
(x) For wet spent fuel storage systems only, any automatically and manually initiated safety system responses;
(xi) The manufacturer and model number (or other identification) of each component that failed during the event; and
(xii) The quantities and chemical and physical forms of the spent fuel, HLW, or reactor-related GTCC waste involved in the event;

(3) An assessment of the safety consequences and implications of the event. This assessment must include the availability of other systems or components that could have performed the same function as the components and systems that failed during the event;

(4) A description of any corrective actions planned as a result of the event, including those to reduce the probability of similar events occurring in the future;

(5) Reference to any previous similar events at the same facility that are known to the licensee; (6) The name and telephone number of a person within the licensee's organization who is knowledgeable about the event and can provide additional information concerning the event and the facility's characteristics; and

(7) The extent of exposure of individuals to radiation or to radioactive materials without identification of individuals by name.

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NONROUTINE REPORT – 49

TITLE: Transport of a Radioactively Contaminated Person to an Offsite Medical Facility

FORMAT: Notification to the NRC Operations Center by telephone.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: 10 CFR 72.75(c)(3):

Any event requiring the transport of a radioactively contaminated person to an offsite medical facility for treatment.

CONTENT: Telephonic:
Content per Attachment 8.A, Section II.

ADDITIONAL INFORMATION: NRC Operations Center telephone number: (301) 816-5100.

CONTROL ROOM ACTIONS: Telephone notification is to be completed as soon as practical but within 8 hours to the NRC Operations Center.

FOLLOWUP ACTIONS: Notifications during the course of the event per10 CFR 72.75(f):

1. Immediately report any further degradation in the level of safety of the ISFSI or other worsening conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made; or any change from one Emergency Class to another; or a termination of the Emergency Class.

2. Immediately report the results of ensuing evaluations or assessments of ISFSI conditions; the effectiveness of response or protective measures taken; and information related to ISFSI behavior that is not understood.

3. Maintain an open, continuous communication channel with the NRC Headquarters Operations Center upon request by the NRC.

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NONROUTINE REPORT – 50

TITLE:	Safety Equipment Disabled or Failed to Function; No Redundant Equipment
FORMAT:	Notification to the NRC Operations Center by telephone.
APPLICABILITY:	CPNPP is subject to this reporting requirement.
REQUIREMENT:	10 CFR 72.75(d)(1): An event in which important to safety equipment is disabled or fails to function as designed when: (i) The equipment is required by regulation, license condition, or certificate of compliance to be available and operable to prevent releases that could exceed regulatory limits, to prevent exposures to radiation or radioactive materials that could exceed regulatory limits, or to mitigate the consequences of an accident; and (ii) No redundant equipment was available and operable to perform the required safety function.
CONTENT:	Telephonic: Content per Attachment 8.A, Section II..
ADDITIONAL INFORMATION:	NRC Operations Center telephone number: (301) 816-5100.
CONTROL ROOM ACTIONS:	Telephone notification within 24 hours after the discovery of any of the above events involving spent fuel, HLW, or reactor-related GTCC waste. Notifications may be delayed if the end of the 24-hour period occurs outside of the NRC's normal working day (i.e., 7:30 a.m. to 5:00 p.m. Eastern Time), on a weekend, or a Federal holiday. In these cases, notification shall be made before 8:00 a.m. Eastern time on the next working day.
FOLLOWUP ACTIONS:	Notifications during the course of the event per10 CFR 72.75(f): 1. Immediately report any further degradation in the level of safety of the ISFSI or other worsening conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made; or any change from one Emergency Class to another; or a termination of the Emergency Class.

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NONROUTINE REPORT – 50

2. Immediately report the results of ensuing evaluations or assessments of ISFSI conditions; the effectiveness of response or protective measures taken; and information related to ISFSI behavior that is not understood.

3. Maintain an open, continuous communication channel with the NRC Headquarters Operations Center upon request by the NRC.

Written report within 30 days per 10 CFR 72.75(g):

Submit a written follow-up report to the Commission within 60 days of the initial notification. Written reports prepared pursuant to other regulations may be submitted to fulfill this requirement if the reports contain all the necessary information and the appropriate distribution is made. These written reports must be of sufficient quality to permit legible reproduction and optical scanning and must be submitted to the NRC in accordance with 10 CFR 72.4. These reports must include the following information:

(1) A brief abstract describing the major occurrences during the event, including all component or system failures that contributed to the event and significant corrective action taken or planned to prevent recurrence;

(2) A clear, specific, narrative description of the event that occurred so that knowledgeable readers conversant with the design of an ISFSI or MRS, but not familiar with the details of a particular facility, can understand the complete event. The narrative description must include the following specific information as appropriate for the particular event:
(i) The ISFSI or MRS operating conditions before the event;
(ii) The status of structures, components, or systems that were inoperable at the start of the event and that contributed to the event;
(iii) The dates and approximate times of occurrences;
(iv) The cause of each component or system failure or personnel error, if known;
(v) The failure mode, mechanism, and effect of each failed component, if known;
(vi) A list of systems or secondary functions that were also affected for failures of components with multiple functions;

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NONROUTINE REPORT – 50

(vii) For wet spent fuel storage systems only, after the failure that rendered a train of a safety system inoperable, an estimate of the elapsed time from the discovery of the failure until the train was returned to service;
(viii) The method of discovery of each component or system failure or procedural error;
(ix) For each human performance related root cause, the licensee shall discuss the cause(s) and circumstances;
(x) For wet spent fuel storage systems only, any automatically and manually initiated safety system responses;
(xi) The manufacturer and model number (or other identification) of each component that failed during the event; and
(xii) The quantities and chemical and physical forms of the spent fuel, HLW, or reactor-related GTCC waste involved in the event;

(3) An assessment of the safety consequences and implications of the event. This assessment must include the availability of other systems or components that could have performed the same function as the components and systems that failed during the event;

(4) A description of any corrective actions planned as a result of the event, including those to reduce the probability of similar events occurring in the future;

(5) Reference to any previous similar events at the same facility that are known to the licensee;

(6) The name and telephone number of a person within the licensee's organization who is knowledgeable about the event and can provide additional information concerning the event and the facility's characteristics; and

(7) The extent of exposure of individuals to radiation or to radioactive materials without identification of individuals by name.

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NONROUTINE REPORT – 51

TITLE: Events involving Category 1 and 2 Quantities of Radioactive Materials

FORMAT: Notification to the appropriate Local Law Enforcement Agency (LLEA) and NRC Operations Center by telephone and follow up written report to the NRC.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: 10CFR37.57(a), (b) and (c); 10CFR37.81(a), (b), (c), (d), (e), (f), (g) and (h).

10CFR37.57

(a) The licensee shall immediately notify the LLEA after determining that an unauthorized entry to a security zone associated with category 1 or 2 radioactive materials resulted in an actual or attempted theft, sabotage, or diversion of a category 1 or category 2 quantity of radioactive material. As soon as possible after initiating a response, but not at the expense of causing delay or interfering with the LLEA response to the event, the licensee shall notify the NRC's Operations Center (301-816-5100). In no case shall the notification to the NRC be later than 4 hours after the discovery of any attempted or actual theft, sabotage, or diversion.

(b) The licensee shall assess any suspicious activity related to possible theft, sabotage, or diversion of category 1 or category 2 quantities of radioactive material and notify the LLEA as appropriate. As soon as possible but not later than 4 hours after notifying the LLEA, the licensee shall notify the NRC's Operations Center (301-816-5100).

(c) The initial telephonic notification required by paragraph (a) must be followed within a period of 30 days by a written report submitted to the NRC by an appropriate method listed in 10CFR37.7. The report must include sufficient information for NRC analysis and evaluation, including identification of any necessary corrective actions to prevent future instances.

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NONROUTINE REPORT – 51

(c) The shipping licensee shall notify the designated LLEA along the shipment route as soon as possible upon discovery of any actual or attempted theft or diversion of a shipment or suspicious activities related to the theft or diversion of a shipment of a category 1 quantity of radioactive material. As soon as possible after notifying the LLEA, the licensee shall notify the NRC's Operations Center (301-816-5100) upon discovery of any actual or attempted theft or diversion of a shipment, or any suspicious activity related to the shipment of category 1 radioactive material.
(d) The shipping licensee shall notify the NRC's Operations Center (301-816-5100) as soon as possible upon discovery of any actual or attempted theft or diversion of a shipment, or any suspicious activity related to the shipment, of a category 2 quantity of radioactive material.
(e) The shipping licensee shall notify the NRC's Operations Center (301-816-5100) and the LLEA as soon as possible upon recovery of any lost or missing category 1 quantities of radioactive material.
(f) The shipping licensee shall notify the NRC's Operations Center (301-816-5100) as soon as possible upon recovery of any lost or missing category 2 quantities of radioactive material.

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NONROUTINE REPORT – 51

(g) The initial telephonic notification required by paragraphs (a) through (d) of this section must be followed within a period of 30 days by a written report submitted to the NRC by an appropriate method listed in 10CFR37.7. A written report is not required for notifications on suspicious activities required by paragraphs (c) and (d) of this section. In addition, the licensee shall provide one copy of the written report addressed to the Director, Division of Security Policy, Office of Nuclear Security and Incident Response, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001. The report must set forth the following information:

(1) A description of the licensed material involved, including kind, quantity, and chemical and physical form;
(2) A description of the circumstances under which the loss or theft occurred;
(3) A statement of disposition, or probable disposition, of the licensed material involved;
(4) Actions that have been taken, or will be taken, to recover the material; and
(5) Procedures or measures that have been, or will be, adopted to ensure against a recurrence of the loss or theft of licensed material.

(h) Subsequent to filing the written report, the licensee shall also report any additional substantive information on the loss or theft within 30 days after the licensee learns of such information.

CONTENT: Telephonic:

A description of the licensed material involved, including kind, quantity, and chemical and physical form, last known location, intended destination, and any other information that may be necessary to aid the recovery of the material.

ADDITIONAL INFORMATION: NRC Operations Center telephone number: (301) 816-5100.

CONTROL ROOM ACTIONS: Telephone notification of appropriate LLEA and NRC

FOLLOWUP ACTIONS: For Category 1 Radioactive material transportation events:

(1)The shipping licensee will provide agreed upon updates to the NRC's Operations Center on the status of an investigation associated with the radioactive material.
(2)The shipping licensee shall notify the NRC's Operations Center and the LLEA as soon as possible upon recovery of any lost or missing category 1 quantities of radioactive material.

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NONROUTINE REPORT – 51

Category 2 Radioactive material transportation events:

(1)If, after 24 hours of its determination that the shipment is lost or missing, the radioactive material has not been located and secured, the licensee shall immediately notify the NRC's Operations Center.

(2)The shipping licensee shall notify the NRC's Operations Center as soon as possible upon recovery of any lost or missing category 2 quantities of radioactive material.

The initial telephonic notification required by 10CFR37.57(a) must be followed within a period of 30 days by a written report submitted to the NRC by an appropriate method listed in 10CFR37.7. The report must include sufficient information for NRC analysis and evaluation, including identification of any necessary corrective actions to prevent future instances.

The initial telephonic notification required by paragraphs (a) through (d) of 10CFR37.81 must be followed within a period of 30 days by a written report submitted to the NRC by an appropriate method listed in 10CFR37.7. A written report is not required for notifications on suspicious activities required by paragraphs (c) and (d) of this section. In addition, the licensee shall provide one copy of the written report addressed to the Director, Division of Security Policy, Office of Nuclear Security and Incident Response, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001.

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NONROUTINE REPORT - 52

TITLE: Reporting Fatalities And Severe Injuries To The Occupational Safety and Health Administration (OSHA)

FORMAT: Notification to OSHA within 8 hours or 24 hours.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 29CFR1904.39(a):

(a) Within eight hours after the death of any employee from a work-related incident and within 24 hours of any work-related inpatient hospitalization of one or more employees, work-related amputation, or work related loss of an eye, you must orally report the fatality/hospitalization by telephone or in person to the Area Office of the Occupational Safety and Health Administration (OSHA), U.S. Department of Labor, that is nearest to the site of the incident. You may also use the OSHA toll-free central telephone number (800-321-6742).

CONTENT: As requested during notification, no additional guidance available.

ADDITIONAL INFORMATION: The Site Safety Manager is responsible for 29CFR1904.39 reporting requirements.

CONTROL ROOM ACTIONS: After notification to OSHA, the NRC may need to be notified within 4 hours per 10CFR50.72(b)(2)(xi), "Any event or situation, related to the health and safety of the public or onsite personnel, or protection of the environment, for which a news release is planned or notification to other government agencies has been or will be made."

FOLLOWUP ACTIONS: None.

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NONROUTINE REPORT - 53

TITLE: Cyber Security Event Notifications

FORMAT: Notification to NRC within 1 hour, 4 hours, or 8 hours, and recording in corrective action program within 24 hours.

APPLICABILITY: CPNPP is subject to this reporting requirement.

REQUIREMENT: This is a paraphrased summary only.
Refer to source documents listed in Attachment 8.B.

From 10 CFR 73.77(a)(1):

(a)(1) requires licensees to notify the NRC within one hour after discovery of a cyber attack that adversely impacted safety-related or important-to-safety functions, security functions, or emergency preparedness functions (including offsite communications); or that compromised support systems and equipment resulting in adverse impacts to safety, security, or emergency preparedness functions within the scope of 10 CFR 73.54.

From 10 CFR 73.77(a)(2):

(a)(2) Requires licensees to notify the NRC within four hours:

(i) After discovery of a cyber attack that could have caused an adverse impact to safety- related or important-to-safety functions, security functions, or emergency preparedness functions (including offsite communications); or that could have compromised support systems and equipment, which if compromised, could have adversely impacted safety, security, or emergency preparedness functions within the scope of 10 CFR 73.54.

(ii) After discovery of a suspected or actual cyber attack initiated by personnel with physical or electronic access to digital computer and communication systems and networks within the scope of 10 CFR 73.54

(iii) After notification of a local, State, or other Federal agency of an event related to implementation of the licensee's cyber security program for digital computer and communication systems and networks within the scope of 10 CFR 73.54 that does not otherwise meet a notification under 10 CFR 73.77(a).

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NONROUTINE REPORT – 53

From 10 CFR 73.77(a)(3):

(a)(3) Requires licensees to notify the NRC within eight hours after receipt or collection of information regarding observed behavior, activities, or statements that may indicate intelligence gathering or pre-operational planning related to a cyber attack against digital computer and communication systems and networks within the scope of 10 CFR 73.54.

From 10 CFR 73.77(b):

(b) Requires licensees to use their site corrective action program (CAP) to record vulnerabilities, weaknesses, failures and deficiencies in their cyber security program as well as record notifications made under paragraph (a) of 10 CFR 73.77 within twenty four hours of their discovery.

From 10 CFR 73.77(c):

(c) Provides the process for conducting cyber security event notifications to the NRC.

From 10 CFR 73.77(d):

(d) Provides the process for submitting written security follow-up reports to the NRC for cyber security event notifications.

From 10 CFR 73.77(d)(3):

(d)(3) Requires licensees to prepare written security follow-up reports on NRC Form 366.

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NONROUTINE REPORT – 53

CONTENT: Be prepared to provide following information, if available at the time of the notification:

a. caller name and callback number,
b. facility name and location,
c. emergency classification (if declared),
d. current event status (e.g., in progress, recovered),
e. event date and time (discovery of, and actual occurrence if known),
f. event description including the following information if available or known:
   (1) cyber security controls involved/affected (if any)
   (2) system(s) involved/affected (SSEP functions, BOP functions, CDAs, CS)
   (3) method used to identify the event (e.g., security controls, audit, failed equipment)
   (4) what occurred during the event
   (5) why the event occurred, if known
   (6) how the event occurred, if known
g. safety, security, EP responses and corrective actions taken,
h. offsite assistance (e.g., requested or not requested, arrived, status),
i. media interest, if any, including licensee issued press releases,
j. source of information(e.g., U.S. Computer Emergency Readiness Team, law enforcement) if a law enforcement agency, provide contact telephone number.

Notifications containing Safeguards Information – Under 10CFR73.22(f)(3), licensees may make notifications of cyber security events specified in 10CFR73.77, which are considered to be extraordinary conditions, containing Safeguards Information to the NRC Headquarters Operations Center without using a secure communications systems. Licensees should not delay notifications of such events beyond one-hour after discovery to wait for secure communications. However, if available, a licensee should use a secure communications system to make the notification and protect the Safeguards Information contained in the report form unintentional or inadvertent disclosure. Licensees should apply this exception to actual events only.

Notifications containing Classified Information – Licensees making notifications under 10CFR73.77 that contain classified National Security Information (NSI) or Restricted Data (RD) should notify the NRC Headquarters Operations Center using a secure communications system equivalent (at a minimum) to the classification level of the notification. Licensees making classified notifications should contact the NRC Headquarters Operations Center at the commercial telephone numbers specified in appendix A to Part 73 and request a number to a secure telephone. If the licensee's secure communications capability is unavailable (e.g., because of the nature of the event), the licensee should provide as much information to the NRC as is required by 10CFR73.77, without revealing or discussing any classified information. The licensee should also indicate to the NRC at the beginning of the notification that its secure

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communications capability is unavailable, in order to prevent the inadvertent disclosure of classified information.

ADDITIONAL INFORMATION: Refer to Cyber Event Reportability Flowchart and Notes (pages 225 - 229)

If it is determined that a cyber attack has occurred, and that it has adversely impacted SSEP functions, (including support systems and equipment), Cyber Security, Operations, Regulatory Affairs, Security, and Emergency Preparedness should review the issue and gain concurrence on the appropriate reporting requirements.

Licensees are not required to make separate notifications for cyber security events that also result in declaration of an emergency. In such circumstances, licensees should make the emergency notifications in accordance with existing regulations (e.g., 10CFR50.72 – NR-13).

Duplicate notifications are not required for other types of events (e.g., notification of a local, state, or other federal agency) that meet the threshold of more than one of NRC's reporting regulations. However, when making such a notification, the licensee should indicate to the NRC that the notification is also to report a cyber security event under a specific paragraph of 10CFR73.77.

CONTROL ROOM ACTIONS: For some cyber security event notifications, the NRC may request an open and continuous communication channel with the NRC Headquarters Operation Center.

FOLLOWUP ACTIONS: For all notification to the NRC according to the provisions of 10CFR73.77 paragraphs (a)(1), (a)(2)(i), or (a)(2)(ii), a written security follow-up report (LER) must be submitted within 60 days.

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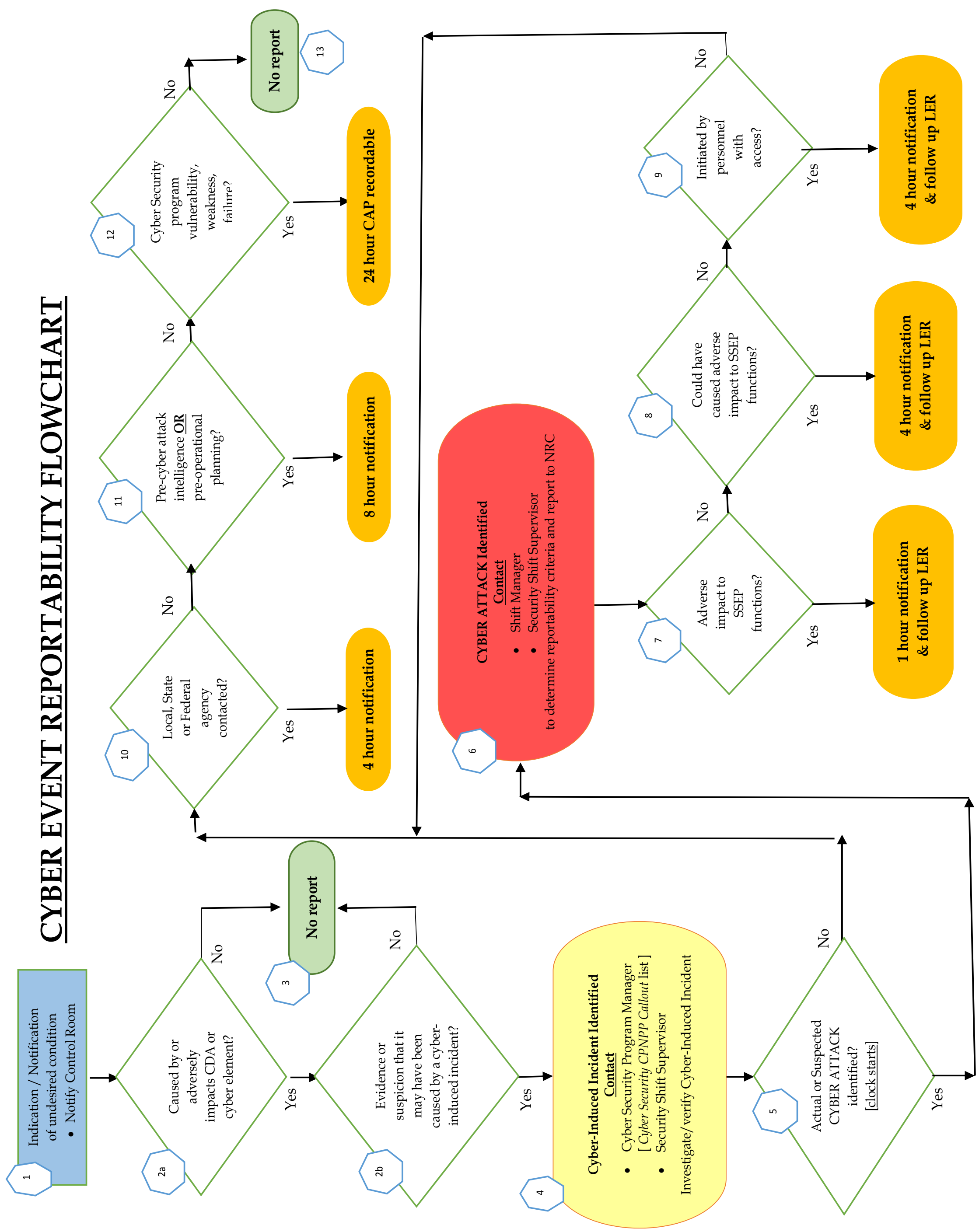

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NONROUTINE REPORT - 53

CYBER EVENT REPORTABILITY FLOWCHART NOTES

Step 1	**BEGIN: Indication / Notification of undesired condition**

Personnel identify the condition (or event). The method by which adverse conditions or events may be identified varies greatly and may include, but is not limited to:

- An observed component failure, malfunction, deficiency, deviation, defect, or an operational disturbance.
- Receipt or collection of information regarding observed behavior, activities, or statements that may indicate intelligence gathering or pre-operational planning related to a CYBER ATTACK against digital computer and communication systems and networks.

Plant personnel communicates issue commensurate with the safety significance. If there is a known immediate security/safety concern, plant personnel notify the Control Room and/or Security. The undesired condition/event is subsequently entered into the corrective action program. Proceed to Step 2a.

Step 2a	**Caused by or adversely impacts CDA or cyber element?**

Operations and/or involved personnel troubleshoot the plant issue to determine the cause.

- If it is immediately apparent that the cause of the plant issue is the result of, or has a known adverse impact to, a CDA or an element of the cyber security program, the issue must be screened to determine if an NRC Event Notification is required. Proceed to step 2b.
- When the immediate cause of the issue is unknown, Operations and/or involved plant personnel may utilize standard processes to further investigate or troubleshoot the issue (e.g., troubleshooting procedures, field investigation, failure investigation process, operability determinations, cause evaluation, etc.). If at any point it is determined that the cause of the plant issue is the result of, or has a known adverse impact to, a CDA or an element of the cyber security program, the issue must be screened to determine if an NRC Event Notification is required. Proceed to step 2b.

This step is intended to determine whether the condition/event involves a CDA or elements of the cyber security program that may require a report under 10 CFR 73.77. This step is not asking whether cyber is the cause of the event, but rather if a CDA or cyber program elements are involved in the event.

What is a cyber element?

- A cyber element refers to any cyber security controls, tools, or personnel behaviors that are associated with the cyber security program or outlined in the site Cyber Security Plan. If there is indication that someone or something has negatively impacted the cyber program, caused elements of the program to become less effective, or there is indication of intelligence gathering or pre-operational planning related to a CYBER ATTACK, this may warrant a cyber security report and further investigation is needed.

  For example:
  Cyber security control impact –
  - System owner was called on by Operations to respond to a DCS alarm; the engineer immediately noticed a rogue connection that was a bypass of the defensive architecture per CSP 4.3.
  - During a walk-down of the turbine control system, an unauthorized thumb drive was found unattended and connected to the HMI.

  Cyber security tools – unauthorized altering or compromise of a kiosk scanning station or whitelisting network.
  Cyber security behaviors – indication that someone is organizing or intelligence gathering for conducting a CYBER ATTACK. These behaviors should be reported to Security for proper investigation.

If it is evident that the event has nothing to do with a CDA or the cyber security program, a cyber security notification is not required at this time. Proceed to Step 3 and exit the process.

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NONROUTINE REPORT - 53

Step 2b	**Evidence or suspicion that it may have been caused by cyber-induced incident?**

If routine troubleshooting reveals no evidence or suspicion that the failure may have been caused by a cyber-induced incident, no report is required. Proceed to Step 3 and exit the process

- Many potential indications of a possible cyber security related problem might also be a simple hardware failure (e.g. bad spot on disk; communications cable/hardware failure, simple broke/fix item, etc.). A cyber-induced incident should not be declared unless either there is confirmation or an indication of a strong potential that there is a Cyber Security aspect to a problem.

If troubleshooting reveals evidence or suspicion that the failure may have been caused by a cyber-induced incident, then the Cyber Security Program Manager (or designee) should be contacted using the *Cyber Security CPNPP Callout* list to investigate and work with the appropriate organizations to determine if a cyber security event notification is required. Proceed to Step 4.

Step 3	**No report required. Exit the process.**
Step 4	**Cyber-induced incident identified**

This DOES NOT start the reportability time clock. This step only identifies a potential cyber event requiring further investigation in accordance with CPNPP Cause Analysis Handbook, Section 4: Cyber Security Incident Handling and Response.

Contact Cyber Security Program Manager (or designee) using the *Cyber Security CPNPP Callout* list & Security Shift Supervisor to assist with investigation. Cyber Security Program Manager (or designee) will coordinate obtaining the necessary technical resources for evaluating the issue and to assist in the reportability determination.

Investigation will be conducted in accordance with CPNPP Cause Analysis Handbook, Section 4: Cyber Security Incident Handling and Response. Proceed to Step 5.

Step 5	**Actual or Suspected CYBER ATTACK identified?**

Cyber Security Program Manager (or designee) performs an initial evaluation to determine if an actual or suspected CYBER ATTACK has occurred. This step helps distinguish between attempts to infiltrate the nuclear environment versus successful entry that could cause an adverse impact. The evaluation of the event needs to consider malicious intent of actions and the adverse impact on a CDA or SSEP function to determine if the event involved a CYBER ATTACK. If signs of a Cyber Attack are not obvious, or there is no indication of a Cyber Attack but further investigation is needed, a preliminary assessment may be required to rule out other common degradations or failures. In such situations, the Cyber Security Program Manager (or designee) may activate the CSIRT for assistance. If CYBER ATTACK is identified, proceed to step 6.

If troubleshooting does not reveal indication of a Cyber Attack, Proceed to Step 10 and determine the appropriate reporting requirements for the cyber condition/event.

Step 6	**CYBER ATTACK identified**

Notify Shift Manager/Security Shift Supervisor that issue is reportable.

As part of evaluating the event, the clock DOES start for the notification once there is indication that one of the three report types is required (CYBER ATTACK Identified).

Proceed to Step 7 to determine reportability criteria and report to NRC.

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NONROUTINE REPORT – 53

Step 7	**Adverse impact to SSEP functions?**

Cyber Security Program Manager (or designee) and supporting organizations determine if a one hour report is required per 10 CFR 73.77(a)(1):

- *A one hour report is required in accordance with 10 CFR 73.77(a)(1) when the CYBER ATTACK adversely impacted safety related or important-to-safety functions, security functions, or emergency preparedness functions (SSEP) (including offsite communications); or compromised support systems and equipment resulting in adverse impacts to safety, security, or emergency preparedness functions within the scope of § 73.54.*

If it is determined that a CYBER ATTACK has occurred, and that it has adversely affected SSEP functions (including support systems and equipment), Operations, Regulatory Affairs, Security, and Emergency Preparedness (where applicable) should review the issue and gain concurrence on the appropriate reporting requirements.

If a one hour report is NOT required, proceed to Step 8.

Step 8	**Could have caused adverse impact to SSEP functions?**

Cyber Security Program Manager (or designee) and supporting organizations determine if a four hour report is required per 10 CFR 73.77(a)(2)(i)):

- *A four hour report is required in accordance with 10 CFR 73.77(a)(2)(i) when the CYBER ATTACK could have caused an adverse impact to SSEP functions (including offsite communications); or that could have compromised support systems and equipment, which if compromised, could have adversely impacted to SSEP functions within the scope of § 73.54.*

Only one (1) plausible assumption needs to be considered when evaluating if the CYBER ATTACK could have caused an adverse impact.

If it is determined that a CYBER ATTACK has occurred, and that it could have caused an adverse impact to SSEP functions (including support systems and equipment), Operations, Regulatory Affairs, Security, and Emergency Preparedness (where applicable) should review the issue and gain concurrence on the appropriate reporting requirements.

If a four hour report is NOT required, proceed to Step 9.

Step 9	**Initiated by personnel with access?**

Cyber Security Program Manager (or designee) and supporting organizations determine if a four hour report is required per 10 CFR 73.77(a)(2)(ii):

- *A four hour report is required in accordance with 10 CFR 73.77(a)(2)(ii) when a suspected or actual CYBER ATTACK was initiated by personnel with physical or electronic (i.e., logical) access to digital computer and communication systems and networks within the scope of § 73.54.*

If it is determined that a CYBER ATTACK has occurred, and that it was initiated by personnel with physical or electronic (i.e., logical) access to digital computer and communication systems and networks, Operations, Regulatory Affairs, Security and Emergency Preparedness (where applicable) should review the issue and gain concurrence on the appropriate reporting requirements.

If a four hour report is NOT required, proceed to Step 10.

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NONROUTINE REPORT – 53

Step 10	**Local, State or Federal agency contacted?**

Cyber Security Program Manager (or designee) and supporting organizations determine if a four hour report is required per 10 CFR 73.77(a)(2)(iii)):

- *A four hour report is required in accordance with 10 CFR 73.77(a)(2)(iii) after notification of a local, State or other Federal agency (e.g., law enforcement, FBI, etc.) of an event related to the licensee's implementation of their cyber security program for digital computer and communication systems and networks within the scope of § 73.54 that does not otherwise require a notification under paragraph (a) of this section.*

If a local, state or federal agency is contacted at any time as a result of cyber-related event, Operations, Regulatory Affairs, Security, and Emergency Preparedness (where applicable) should review the issue and gain concurrence on the appropriate reporting requirements.

If a four hour report is NOT required, proceed to Step 11.

Step 11	**Pre-CYBER ATTACK intelligence OR pre-operational planning?**

Cyber Security Program Manager (or designee) and supporting organizations determine if an eight hour report is required per 10 CFR 73.77(a)(3):

- *An eight hour report is required in accordance with 10 CFR 73.77(a)(3) after receipt or collection of information regarding observed behavior, activities or statements that may indicate intelligence gathering or pre-operational planning related to a CYBER ATTACK against digital computer and communication systems and networks within the scope of § 73.54.*

After receipt or collection of information regarding observed behavior, activities, or statements that may indicate intelligence gathering or pre-operational planning for a CYBER ATTACK, Operations, Regulatory Affairs, Security, and Emergency Preparedness (where applicable) should review the issue and gain concurrence on the appropriate reporting requirements.

If an eight hour report is NOT required, proceed to Step 12.

Step 12	**CS Program vulnerability, weakness, failure?**

Cyber Security Program Manager (or designee) and supporting organizations determine if the issue constitutes a vulnerability, weakness, failure or deficiency of the Cyber Security Program and ensure such issues are recorded in the site corrective action program within twenty-four (24) hours of their discovery.

If recording in the site corrective action program within 24 hours is NOT required, proceed to Step 13 and exit the process.

Step 13	**No report required. Exit the process.**

Rev/PCN	Affected Pages	Description of Change
19/1	1	Added the PCN number 1 and effective date
	33	Added Title to NR 41. Deleted notification to the POC and RMS. Deleted the discussion of sabotage reporting requirements and the ABN-915 words to avoid confusion. Changed the Oncor notification requirement for only items 5 to 11.
	40	Added NR 41 to “Bombs, Threat”
	42	Added NR-41 to “Threats or attempts to cause”
	175	Deleted notifications to POC and RMS from “Format” and added “as required below.” Under “Requirement” replaced a comma with the word “and.” Added a Note to give some examples of reportable events. Deleted the discussion after Item 4 on ABN-915 to avoid any confusion.
	176	Deleted the requirement to notify the POC and RMS. Changed the notification to Oncor for only Items 5 to 11.
19/2	3, 95, 103 - 122	Minor editorial corrections.
	7, 154	Change “Director, Plant Support” to “Manager, Environmental.”
	39	Added OSHA 8 hour and 24 reporting requirements to the list.
	60	Added NR-52 to the list.
	109	Add timing requirements for 60 day LER.
	144	In NR-22, clarify Control Room Actions for a reportable Security event.
	201	Added new NR-52 for reporting fatalities/injuries to OSHA.
	All	Renumbered all pages.
20	4-8	Add new definitions related to Loss Of Emerg Preparedness Capabilities RALs.
	118 - 140	Add new RALs for Loss Of Emerg Preparedness Capabilities.
	192	Add Note 3 related to Unmanned Aerial Systems
	221	Add clarification that a 10CFR50.72(b)(2)(xi) report may be required for reports to OSHA.
	All	Renumbered all pages.
20/1	1	Added PCN number and effective date/time
	35	Deleted “also know at Luminant Energy or TXU Energy” and moved CR notifying Oncor to next page
	36	Added CR notifications to Oncor and contact M&R for possible NERC relay misoperation
	37, 197	Changed “16.12” to “16.14” and corrected “Stewart” to “Steward”
	191	Changed a “should” statement to “shall” and added that the CR should contact M&R for

Rev/PCN	Affected Pages	Description of Change
		possible NERC relay misoperation
	192	Changed the CR actions to be consistent with the other sections of NR-41 and added CR to notify M&R for possible NERC relay misoperation
20/2	1	Changed PCN to 2 and added effective date
	35	Changed item 11 to 10
	36	Deleted item 11 and changed items 11 to 10
	191	Deleted item 11
	192	Changed items 11 to 10
20/3	138	Changed RIS 05-20 to IMC-0326
20/4	4,16,31,47,162	Change EPA/NPDES references to TCEQ/TPDES.
	8,9,11,37,70,91,101,103,107,140, 156,160,165,168,197	Title and organizational changes
	18,19,29,35,76,83,106,116,117,118 122,123, 124, 125,126,127,128,130 135,136, 138,141, 159, 160,161,162 178,190,197,202	Correct uses of “should,” “shall,” “will,” “would,” etc.
	115	Clarify that most unplanned trips are reportable per 10CFR50.72(b)(3)(iv)(A)
21	4,5,6,7,11,43,44,47,65,221,222,223, 224,225,226,227,228,229	Integrate the new Cyber Security Reporting Rule 10CFR73.77 as mandated in NEI 15-09, Rev. 0.
	3,4,5,6,7,8,9,17- 42	Editorial changes to section and header numbering
	133,134	Correct RAL #2 under Major Loss Of Offsite Response Capability to reflect that CPNPP does not have a FEMA-approved backup alerting method that meets the performance criteria of 10CFR50, App. E, Section IV.D.3.
	All	All pages changed due to renumbering.

Initial Conditions: **Given the following conditions:**

JPM Cue Sheet #1

- **A high dose maintenance activity is scheduled in the Fuel Building**
- **The general dose rate in the area is 100 mrem / hour but can be reduced to 25 mrem / hour if lead shielding is installed**
- **It will take NEOs A & B 30 minutes to install the shielding**
- **Independent of the shielding, it will take NEO A 2 hours or NEOs A & B 1.5 hours to perform the maintenance**

Initiating Cue: **The Work Control Supervisor directs you to PERFORM the following:**

- **CALCULATE the dose received when performing the maintenance for each of the following conditions:**

  - **NEO A without shielding** 200 **mrem**
  - **NEOs A & B without shielding** 300 **mrem**
  - **NEO A with shielding** 100 **mrem**
  - **NEOs A & B with shielding** 175 **mrem**

Initial Conditions:	**Given the following conditions:**
JPM Cue Sheet #2	• **The Shift Manager was notified by Radiation Protection that an individual handling radioactive licensed material received 5.5 REM TEDE in a 3 hour period**
Initiating Cue:	**The Shift Manager directs you to PERFORM the following:**
	• **DETERMINE Oral and Written Reportability Requirements, if any**

- **Oral Reporting Requirement** **within 24 hours**
- **Written Reporting Requirement** **within 30 days**

DETERMINED Oral Reporting Requirements per STA-501, Attachment 8D/4, page 7 of 12: "Any event involving licensed material possessed that may have caused or threatens to cause exposure to individual: ≥ 5 Rem TEDE" – 24 hour notification via ENS, AND 30 day LER

Facility: CPNPP JPM # NRC SA5 Task # SO1136M K/A # 2.4.41 2.9 / 4.6

Title: Classify an Emergency Plan Event / Determine if an Upgrade is Required

Examinee (Print): ________________________________

Testing Method:

Simulated Performance:	______	Classroom:	X
Actual Performance:	X	Simulator:	______
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

Time 0700

- Unit 1 experienced a Loss of All Offsite Power 30 minutes ago.
- Both Safeguards Buses are deenergized.
- Train A Emergency Diesel Generator was just shut down following turbocharger failure.
- Train B Emergency Diesel Generator will NOT start in either Emergency or Normal modes.
- Pressurizer level is 0%.
- Reactor Coolant System pressure is 30 PSIG and stable.
- Core Exit Thermocouple temperatures are 780ºF and rising.
- Containment pressure is 30 PSIG and stable.
- Steam Generator wide range levels are 30% and slowly lowering.
- No Reactor Vessel Level Indication System lights are lit.
- Turbine Driven Auxiliary Feedwater Pump tripped on overspeed and cannot be reset.

Initiating Cue: The Shift Manager directs you to PERFORM the following:

- DETERMINE the Emergency Action Level Group / Category, Subcategory, and Event Classification per EPP-201, Assessment of Emergency Action Levels, Emergency Classification, and Plan Activation. DETERMINE the MAXIMUM amount of time available to complete the notification.

EAL Classification ________________________________

MAXIMUM Amount of Time to Complete Notification ________

____

Updated Conditions: Given the following conditions:

Time 0730

- Unit 1 experienced a Loss of All Offsite Power 60 minutes ago.
- Both Safeguards Buses are deenergized.
- Train A Emergency Diesel Generator was shut down following turbocharger failure.
- Train B Emergency Diesel Generator will NOT start in either Emergency or Normal modes.
- Pressurizer level is 0%.
- Reactor Coolant System pressure is 30 PSIG and stable.
- Core Exit Thermocouple temperatures are 980ºF and slowly rising.
- Containment pressure is 30 PSIG and stable.
- Steam Generator wide range levels are 20% and slowly lowering.
- No Reactor Vessel Level Indication System lights are lit.
- Turbine Driven Auxiliary Feedwater Pump has NOT been restored
- Off-site power will be restored in 1.5 hours

Initiating Cue: Based on the updated conditions, DETERMINE if an upgrade (escalate) or follow-up (update) message is required. DETERMINE the MAXIMUM amount of time to complete the notification message (assume the initial notification time was the initial message time).

A ____________________________ message is required

MAXIMUM Amount of Time to Complete Notification ___________

____

Task Standard: UTILIZED EPP-201, EPP-203, Emergency Action Level Hot and Cold Classification Charts, and the Critical Safety Function Status Trees. DETERMINED the Event Category and Event Classification using the Emergency Action Level Hot & Cold Classification Charts including the amount of time to complete the notification. DETERMINED if a Follow-up or Upgrade notification was required and the amount of time to complete the notification.

Ref. Materials: EPP-201, Assessment of Emergency Action Levels, Emergency Classification, and Plan Activation, Rev. 13

EPP-201, Emergency Action Level Technical Bases Document, Rev. 1

CPNPP Emergency Action Level Hot & Cold Classification Charts, Rev. 13.

EOP Critical Safety Function Status Trees, Rev. 9

Validation Time: 30 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ____________

CLASSROOM SETUP

EXAMINER:

MAKE the following available in the classroom:

- **EPP-201, Assessment of Emergency Action Levels, Emergency Classification, and Plan Activation (Procedure 1)**
- **EPP-201, Emergency Action Level Technical Bases Document (Procedure 2)**
- **EPP-203, Notifications (Procedure 3)**
- **CPNPP Emergency Action Level Hot & Cold Classification Charts (Charts)**
- **EOP Critical Safety Function Status Trees (Status Trees)**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from CPNPP Emergency Action Levels Hot.**
Perform Step: 1	DETERMINE the Event Category.
Standard:	REFERRED to CPNPP Emergency Action Levels Hot and Cold and DETERMINED the following chart is applicable: • CPNPP EAL Hot Conditions
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2	MATCH plant conditions in the EAL Group / Category.
Standard:	IDENTIFIED EAL Group / Category as System Malfunctions (S).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3	MATCH plant conditions in the selected EAL Subcategory.
Standard:	IDENTIFIED EAL Subcategory as Loss of AC Power (1).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4√	CLASSIFY the event.
Standard:	CLASSIFIED the event as a SITE AREA EMERGENCY (SS1.1).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 5√	DETERMINE MAXIMUM amount of time to complete notification
Standard:	DETERMINED Message must be sent within 15 minutes of Declaration (which must occur at 0700) or at 0715
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**Hand applicant second cue sheet with updated conditions**
Perform Step: 6√	DETERMINE if an upgrade or follow up message is required
Standard:	DETERMINED a follow-up message is required.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 7√	DETERMINE MAXIMUM amount of time to complete notification for updated conditions.	
Standard:	DETERMINED Message must be sent within 1 hour of the initial notification or at 0815 (Initial time of notification plus one hour)	
Terminating Cue:	**This JPM is complete.**	
Comment:		**SAT** ☐ **UNSAT** ☐

STOP TIME:	

Initial Conditions:

At Time 0700

Given the following conditions:

- **Unit 1 experienced a Loss of All Offsite Power 15 minutes ago.**
- **Both Safeguards Buses are deenergized.**
- **Train A Emergency Diesel Generator was just shut down following turbocharger failure.**
- **Train B Emergency Diesel Generator will NOT start in either Emergency or Normal modes.**
- **Pressurizer level is 0%.**
- **Reactor Coolant System pressure is 30 PSIG and stable.**
- **Core Exit Thermocouple temperatures are 780ºF and rising.**
- **Containment pressure is 30 PSIG and stable.**
- **Steam Generator wide range levels are 30% and slowly lowering.**
- **No Reactor Vessel Level Indication System lights are lit.**
- **Turbine Driven Auxiliary Feedwater Pump tripped on overspeed and cannot be reset.**

Initiating Cue:

The Shift Manager directs you to PERFORM the following:

- **DETERMINE the Emergency Action Level Group / Category, Subcategory, and Event Classification per EPP-201, Assessment of Emergency Action Levels, Emergency Classification, and Plan Activation. DETERMINE the MAXIMUM amount of time available to complete the notification.**

EAL Classification ________________________________

MAXIMUM Amount of Time to Complete Notification ______

____

Updated Conditions: **Given the following conditions:**

Time 0730

- **Unit 1 experienced a Loss of All Offsite Power 45 minutes ago.**
- **Both Safeguards Buses are deenergized.**
- **Train A Emergency Diesel Generator was shut down following turbocharger failure.**
- **Train B Emergency Diesel Generator will NOT start in either Emergency or Normal modes.**
- **Pressurizer level is 0%.**
- **Reactor Coolant System pressure is 30 PSIG and stable.**
- **Core Exit Thermocouple temperatures are 980ºF and slowly rising.**
- **Containment pressure is 30 PSIG and stable.**
- **Steam Generator wide range levels are 20% and slowly lowering.**
- **No Reactor Vessel Level Indication System lights are lit.**
- **Turbine Driven Auxiliary Feedwater Pump has NOT been restored**
- **Off-site power will be restored in 1.5 hours**

Initiating Cue: **Based on the updated conditions, DETERMINE if an <u>upgrade</u> (escalate) or <u>follow-up</u> (update) message is required. DETERMINE the MAXIMUM amount of time to complete the notification message (assume the initial notification time was the initial message time).**

A ________________________ message is required

MAXIMUM Amount of Time to Complete Notification ______

____

COMANCHE PEAK NUCLEAR POWER PLANT

EMERGENCY PLAN MANUAL

FOR EMPLOYEE USE: | DATE VERIFIED/INITIALS___________ /____________ LATEST PCN/EFFECTIVE DATE: _____ /_________

LEVEL OF USE:
INFORMATION USE

ASSESSMENT OF EMERGENCY ACTION LEVELS EMERGENCY CLASSIFICATION AND PLAN ACTIVATION

PROCEDURE NO. EPP-201

REVISION NO. 13

SORC Meeting No.: 16-021 Date: 12/08/2016

EFFECTIVE DATE: 01/06/2017 12:00

MAJOR REVISON

PREPARED BY: (Print): Kelly Faver EXT: 5628

TECHNICAL REVIEW BY (Print) Gary Wiechering EXT: 0180

APPROVED BY: John Dreyfuss DATE: 8-Dec-2017

PLANT MANAGER

1.0 PURPOSE (C-01882)

This procedure provides guidance to the Shift Manager, TSC Manager, or EOF Manager to assist in the classification of an emergency as either an "Unusual Event", "Alert", "Site Area Emergency", or "General Emergency".

2.0 APPLICABILITY

This procedure applies to the Shift Manager, TSC Manager, or EOF Manager in the event of an emergency situation at CPNPP.

3.0 DEFINITIONS/ACRONYMS

3.1 Alert - Events are in progress or have occurred which involve an actual or potential substantial degradation of the level of safety of the plant or a security event that involves probable life threatening risk to site personnel or damage to site equipment because of hostile action. Any releases are expected to be limited to small fractions of the Environmental Protection Agency (EPA) Protection Action Guideline (PAG) exposure levels. [C-05703]

3.2 Emergency Action Levels (EALs) – A Pre-determined, Site-specific, observable threshold for a plant Initiating Condition that places the plant in a given emergency class. An EAL can be: an instrument reading; an equipment status indicator; a measurable parameter; a discrete, observable event; or another phenomenon which, if it occurs, indicates entry into a particular emergency class.

3.3 Emergency Classification - A classification system of emergency severity based on projected or confirmed initiating conditions/emergency action levels. The classes, from least to most severe, are: Unusual Event, Alert, Site Area Emergency and General Emergency.

3.4 Emergency Conditions - Situations which occur that can cause or may threaten to cause hazards affecting the health and safety of employees or the public, or which may result in damage to property.

3.5 Initiating Condition (IC) – An event or condition that aligns with the definition of one of the four emergency classification levels by virtue of the potential or actual effects or consequences.

3.6 General Emergency – Events are in progress or have occurred which involve actual or imminent substantial core degradation or melting with potential for loss of containment integrity or hostile actions that result in an actual loss of physical control of the facility. Releases can be reasonably expected to exceed EPA Protective Action Guideline (PAG) exposure levels offsite for more than the immediate site area. [C-05705]

3.7 Site Area Emergency - Events are in progress or have occurred which involve actual or likely major failures of plant functions needed for protection of the public or hostile actions that result in intentional damage or malicious acts; (1) toward site personnel or equipment that could lead to the likely failure of or; (2) that prevent effective access to equipment needed for the protection of the public. Any releases are not expected to result in exposure levels which exceed EPA Protective Action Guidelines exposure levels beyond the site boundary. [C-05704]

3.8 Unusual Event - Events are in progress or have occurred which indicate a potential degradation in the level of safety of the plant or indicate a security threat to facility protection has been initiated. No releases of radioactive material requiring offsite response or monitoring are expected unless further degradation of safety systems occurs. [C-05702]

4.0 INSTRUCTIONS

4.1 General Instructions

NOTE:	For the purposes of this procedure, the title Emergency Coordinator is used generically to refer to the position with responsibility for emergency classifications, even though the Emergency Coordinator may not always have this responsibility.

4.1.1 In most cases the decision to declare, upgrade, or proceed to recovery/closeout of an emergency rests with the Emergency Coordinator. When the EOF Manager is the Emergency Coordinator, he may elect to have the TSC Manager retain responsibility for assessing, classifying, and declaring an emergency condition.

4.1.2 The “Emergency Action Level Technical Bases Document” and the “Emergency Action Level Classification Matrix”, cites specific conditions that denote whether the emergency is to be classified as an Unusual Event, Alert, Site Area Emergency or General Emergency. The Emergency Action Level Classification Matrix is provided as guidance to assist the Emergency Coordinator in making that decision. In many cases, a very general statement has been used to denote the emergency action level (EAL) on the Emergency Action Level Classification Matrix. This was done to allow the Emergency Coordinator flexibility to assess any undefinable parameters which may exist. [C-05327]

4.1.3 Plant-specific operator actions required to mitigate the emergency condition are prescribed in the appropriate Abnormal Conditions Procedures or Emergency Operating Procedures (ABN's or EOP's) and are independent of any actions required by this Emergency Plan Procedure.

4.2 <u>Use of the EAL Classification Matrix</u>

4.2.1 The CPNPP EAL scheme includes the following features:

4.2.1.1 Division of the EAL set into three broad groups:

- EALs applicable under all plant operating modes – This group would be reviewed by the EAL-user any time emergency classification is considered.

- EALs applicable only under hot operating modes – This group would only be reviewed by the EAL-user when the plant is in Hot Shutdown, Hot Standby, Startup, or Power Operation mode.

- EALs applicable only under cold operating modes – This group would only be reviewed by the EAL-user when the plant is in Cold Shutdown, Refueling or Defueled mode.

4.2.1.2 The purpose of the groups is to avoid review of hot condition EALs when the plant is in a cold condition and avoid review of cold condition EALs when the plant is in a hot condition. This approach significantly minimizes the total number of EALs that must be reviewed by the EAL-user for a given plant condition, reduces EAL-user reading burden and, thereby, speeds identification of the EAL that applies to the emergency.

4.2.1.3 Within each of the above three groups, assignment of EALs to categories/subcategories – Category and subcategory titles are selected to represent conditions that are operationally significant to the EAL-user.

4.2.1.4 Subcategories are used as necessary to further divide the EALs of a category into logical sets of possible emergency classification thresholds. The CPNPP EAL categories/subcategories are listed below.

EAL Groups, Categories and Subcategories

EAL Group/Category	EAL Subcategory
Any Operating Mode:	
R – Abnormal Rad Levels / Rad Effluent	1 – Rad Effluent 2 – Irradiated Fuel Event 3 – Area Radiation Levels
E – ISFSI	1 – Confinement Boundary
H – Hazards	1 – Security 2 – Seismic Event 3 – Natural or Tech. Hazard 4 – Fire 5 – Hazardous Gases 6 – Control Room Evacuation 7 – EC Judgment
Hot Conditions:	
S – System Malfunction	1 – Loss of Emergency AC Power 2 – Loss of Vital DC Power 3 – Loss of Control Room Indications 4 – RCS Activity 5 – RCS Leakage 6 – RPS Failure 7 – Loss of Communications 8 – CMT Failure 9 – Hazardous Event Affecting Safety Systems
F – Fission Product Barrier Degradation	None
Cold Conditions:	
C – Cold Shutdown / Refueling System Malfunction	1 – RCS Level 2 – Loss of Emergency AC Power 3 – RCS Temperature 4 – Loss of Vital DC Power 5 – Loss of Communications 6 – Hazardous Event Affecting Safety Systems

4.2.1.5 The primary tool for determining the emergency classification level is the EAL Classification Matrix.

- To help in determining the EAL Classification, color coded copies of the EAL Classification Matrix are maintained in the Control Room, the Technical Support Center, and the Emergency Operations Facility and selected other locations.

4.2.1.6 The user of the EAL Classification Matrix may consult the EAL Technical Bases Document in order to obtain additional information concerning the EALs under classification consideration.

4.2.2 Fission Product Barrier Loss/Potential Loss Matrix and Bases

4.2.2.1 If a cell in the Fission Product Barrier Matrix contains more than one numbered threshold, each of the numbered thresholds, if exceeded, signifies a Loss or Potential Loss of the barrier. It is not necessary to exceed all of the thresholds in a category before declaring a barrier Loss/Potential Loss.

4.2.2.2 Subdivision of the Fission Product Barrier Matrix by category facilitates association of plant conditions to the applicable fission product barrier Loss and Potential Loss thresholds. This structure promotes a systematic approach to assessing the classification status of the fission product barriers.

4.2.2.3 When equipped with knowledge of plant conditions related to the fission product barriers, the EAL-user first scans down the category column of the Fission Product Barrier Matrix, locates the likely category and then reads across the row of fission product barrier Loss and Potential Loss thresholds in that category to determine if any threshold has been exceeded. If a threshold has not been exceeded in that category row, the EAL-user proceeds to the next likely category and continues review of the row of thresholds in the new category

4.2.2.4 If the EAL-user determines that a Loss threshold has been exceeded, a check mark or circle may be placed in or around the threshold box for the Loss column. This signifies that the threshold barrier is lost. Similarly, this is done for a Potential Loss threshold that has been exceeded.

4.2.2.5 The EAL-user must examine each of the three fission product barriers to determine if other barrier thresholds in the category are lost or potentially lost. For example, if Containment radiation is sufficiently high (i.e., greater than 1,110 R/hr), a Loss of the Fuel Clad and RCS barriers and a Potential Loss of the Containment barrier exist. Barrier Losses and Potential Losses are then applied to the algorithms given in EALs FG1.1, FS1.1 and FA1.1 to determine the appropriate emergency classification.

4.2.3 Classifying Transient Events

4.2.3.1 The key consideration during a Transient Event is to determine whether or not further plant damage occurred while the corrective actions were being taken. In some situations, this can be readily determined, in other situations, further analyses may be necessary (e.g., coolant radiochemistry following an ATWT event, plant structural examination following an earthquake, etc.). Classify the event as indicated and terminate the emergency once assessment shows that there were no consequences from the event and other termination criteria are met.

4.2.3.2 Existing guidance for classifying transient events addresses the period of time of event recognition and classification (15 minutes). However, in cases when EAL declaration criteria may be met momentarily during the normal expected response of the plant, declaration requirements should not be considered to be met when the conditions are a part of the designed plant response, or result from appropriate Operator actions.

4.2.3.3 There may be cases in which a plant condition that exceeded an EAL was not recognized at the time of occurrence but is identified well after the condition has occurred (e.g., as a result of routine log or record review), and the condition no longer exists. In these cases, an emergency should not be declared. Reporting requirements of 10 CFR 50.72 are applicable and the guidance of NUREG-1022, Event Reporting Guidelines 10 CFR 50.72 and 50.73, should be applied.

4.2.4 Multiple Events and Classification Upgrading/Downgrading

4.2.4.1 When multiple, simultaneous events occur, the emergency classification level is based on the highest EAL reached. Also, there is no “additive” effect from multiple EALs meeting the same classification.

- For example, if an Alert and a Site Area Emergency are both met, the Site Area Emergency should be declared; or, if two Alerts are met, an Alert should be declared.

  Emergency classification level upgrading for multi-unit stations such as CPNPP with shared safety-related systems and functions must also consider the effects of a loss of a common system on more than one unit (e.g. potential for radioactive release from more than one core at the same site).

4.2.4.2 Although not normally performed, a situation may exist where downgrading the classification is appropriate. The classification may be downgraded when the event or condition that meets the highest IC and EAL no longer exists. If downgrading the classification is deemed appropriate, the new classification would then be based on lower applicable IC(s) and EAL(s). The classification may also be terminated in accordance with EPP-121, Reentry, Recovery, & Closeout.

4.3 Emergency Classification Initial Actions [C-08621]

NOTE:	Once indication of an abnormal condition is available, classification declaration must be made within 15 minutes. This time is available to ensure that the classification and subsequent actions associated with the classification, if warranted, are appropriate. It does not allow a delay of 15 minutes if the classification is recognized to be necessary. It is meant to provide sufficient time to accurately assess the emergency conditions and then evaluate the need for an emergency classification based on the assessment performed. The decision to terminate the event or enter Recovery is NOT time independent.

NOTE:	IF a higher classification is made prior to transmitting an event notification, THEN notification for the higher classification can supersede the event notification, provided that it can be performed within the 15-minute timeframe of the previous event. IF the notification of the higher classification cannot be performed within the 15-minute timeframe of the previous event classification, THEN the previous event notification is required within its 15-minute timeframe, and the subsequent event notification is required within its 15-minute timeframe.

CAUTION:	Shutdown and outage conditions should be given special consideration since they will likely create abnormalities such as the loss of containment integrity or loss of the RCS pressure boundary (refueling, mid-loop operations, equipment hatch open, etc.). These types of boundary breaches combined with a plant transient (loss of AC power, etc.) may create a worse situation than would be expected if the Unit was at power.

4.3.1 Upon recognition that an abnormal or emergency condition exists, the Shift Manager shall be immediately notified.

4.3.2 Operators shall refer to the appropriate ABN's or EOP's and take actions based upon the indicated symptoms.

4.3.3 The Shift Manager shall evaluate the conditions to determine the need for classifying into one of the four (4) Emergency Classification levels.

4.3.4 If the conditions do not fit any of the general descriptions on the EAL Classification Matrix, the Shift Manager should evaluate the conditions and, if appropriate, classify the emergency based upon professional judgment. If classification is not warranted, no further action is required except to continue monitoring the event.

4.3.5 If the on-duty Shift Manager determines that the conditions fit one or more of the Emergency Classifications shown on the matrix, the Shift Manager shall assume the role of Emergency Coordinator as prescribed in Procedure EPP-109, "Duties and Responsibilities of the Emergency Coordinator/Recovery Manager" and consult his Position Assistant Document (PAD) for further actions. [C-05687, 01278]

4.3.6 When an abnormal or emergency condition is being evaluated, **REFER** to the EAL Classification Matrix and **PERFORM** the following:

- **IDENTIFY** the Unit Mode for the state of the plant prior to the abnormal condition (Operating Modes are identified in respective EALs).
- **REVIEW** the IC(s) applicable to the operating mode as follows.
  - Starting with the highest (General Emergency) classification level on the left side of the matrix and continue to the lowest (Unusual Event) classification level on the right side of the matrix.
  - **If** more than one IC applies to the event, **THEN SELECT** the IC for the highest classification (from all of the IC(s) that were determined to have been met).

- **REVIEW** the EAL Threshold Values for the IC(s).

  - **If** the EAL Threshold Values have been met or exceeded, **THEN**:

    - **NOTE** the EAL number associated with the IC.

    - **DECLARE** the event. For events affecting both Units, the highest classification on either Unit shall be declared.

4.4 Subsequent Actions [C-05701]

The Shift Manager or Emergency Coordinator shall continually monitor plant conditions and compare the current plant conditions to the EAL Classification Matrix to determine whether a change in emergency classification is warranted and whether to escalate the emergency classification or proceed to EPP-121, "Reentry, Recovery and Closeout".

5.0 REFERENCES

5.1 Emergency Action Level Technical Bases Document

5.2 CPNPP Emergency Plan, Section 2.0

5.3 EPP-109, “Duties and Responsibilities of the Emergency Coordinator/Recovery Manager”

5.4 NUREG-0654/FEMA-REP-1, Rev. 1, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants”

5.5 10CFR, Part 50.72, “Notification of Significant Events”

5.6 NEI 99-01 Rev. 6

5.7 CPSES FSAR Chapter 15

5.8 EPP-121, “Reentry, Recovery and Closeout”

6.0 ATTACHMENTS/FORMS

6.1 Attachments

6.1.1 Attachment 1, “Initiating Condition (IC) Table”

6.1.2 Attachment 2, “EAL Classification Matrix”

6.1.3 Attachment 3, “EAL Technical Bases Document”

6.2 Forms

None

Attachment 1
Initiating Condition (IC) Table
[C-05327, 05701, 05702, 05703, 05704, 05705, 09308, 26728]
Page 1 of 2

Categories	GE	SAE	Alert	UE
ALL Modes				
Abnormal Rad Levels / Rad Effluent (R)	Rad Effluent	Rad Effluent	Rad Effluent	Rad Effluent
	Irradiated Fuel Event	Irradiated Fuel Event	Irradiated Fuel Event	Irradiated Fuel Event
			Area Radiation Levels	
ISFSI				Confinement Boundary
Hazards (H)	Security	Security	Security	Security
				Seismic Event
				Natural or Tech. Hazard
				Fire
			Hazardous Gases	
		Control Room Evacuation	Control Room Evacuation	
	EC Judgment	EC Judgment	EC Judgment	EC Judgment

Categories	GE	SAE	Alert	UE
HOT Conditions				
System Malfunctions (S)	Loss of Emer. AC Power	Loss of Emer. AC Power	Loss of Emer. AC Power	Loss of Emer. AC Power
		Loss of Vital DC Power		
			Loss of Control Room Indications	Loss of Control Room Indications
				RCS Activity
				RCS Leakage
		RPS Failure	RPS Failure	RPS Failure
				Loss of Comm.
				CMT Failure
			Hazardous Event Affecting Safety Systems	
Fission Product Barrier Degradation (F)	Fission Product Barrier Degradation	Fission Product Barrier Degradation	Fission Product Barrier Degradation	

Attachment 1
Initiating Condition (IC) Table
[C-05327, 05701, 05702, 05703, 05704, 05705, 09308, 26728]
Page 2 of 2

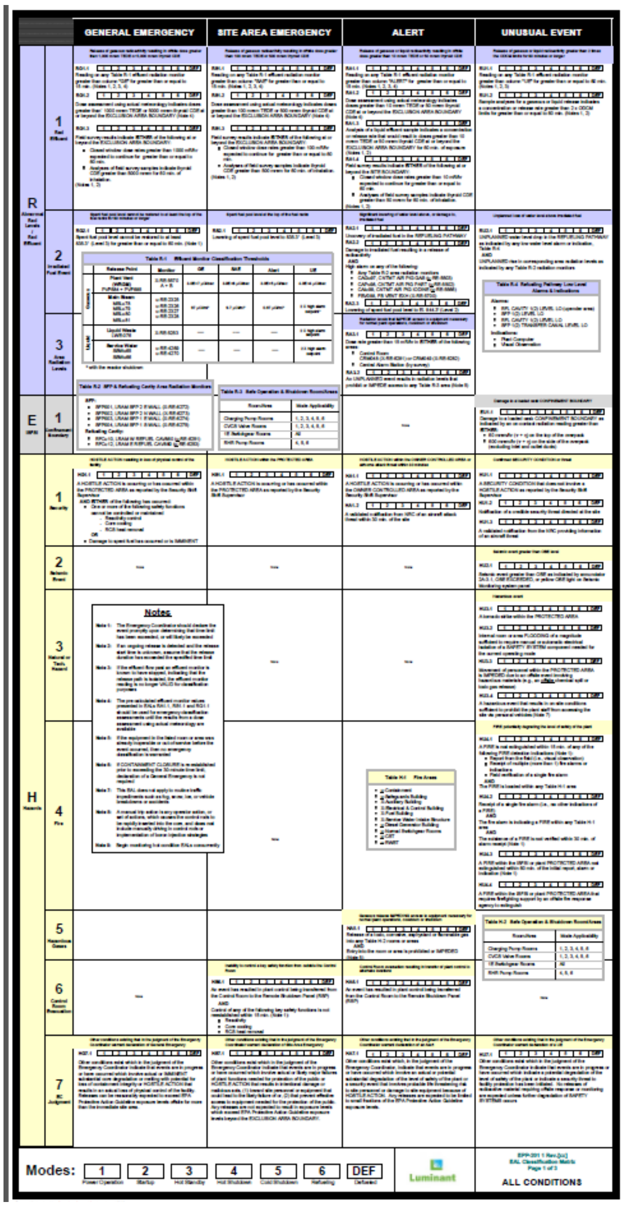
<table>
<tr><th>Categories</th><th>GE</th><th>SAE</th><th>Alert</th><th>UE</th></tr>
<tr><td colspan="5">COLD Conditions</td></tr>
<tr><td rowspan="6">Cold SD / Refueling System Malfunct. (C)</td><td>RCS Level</td><td>RCS Level</td><td>RCS Level</td><td>RCS Level</td></tr>
<tr><td></td><td></td><td>Loss of Emer. AC Power</td><td>Loss of Emer. AC Power</td></tr>
<tr><td></td><td></td><td>RCS Temp.</td><td>RCS Temp.</td></tr>
<tr><td></td><td></td><td></td><td>Loss of Vital DC Power</td></tr>
<tr><td></td><td></td><td></td><td>Loss of Comm.</td></tr>
<tr><td></td><td></td><td>Hazardous Event Affecting Safety Systems</td><td></td></tr>
</table>

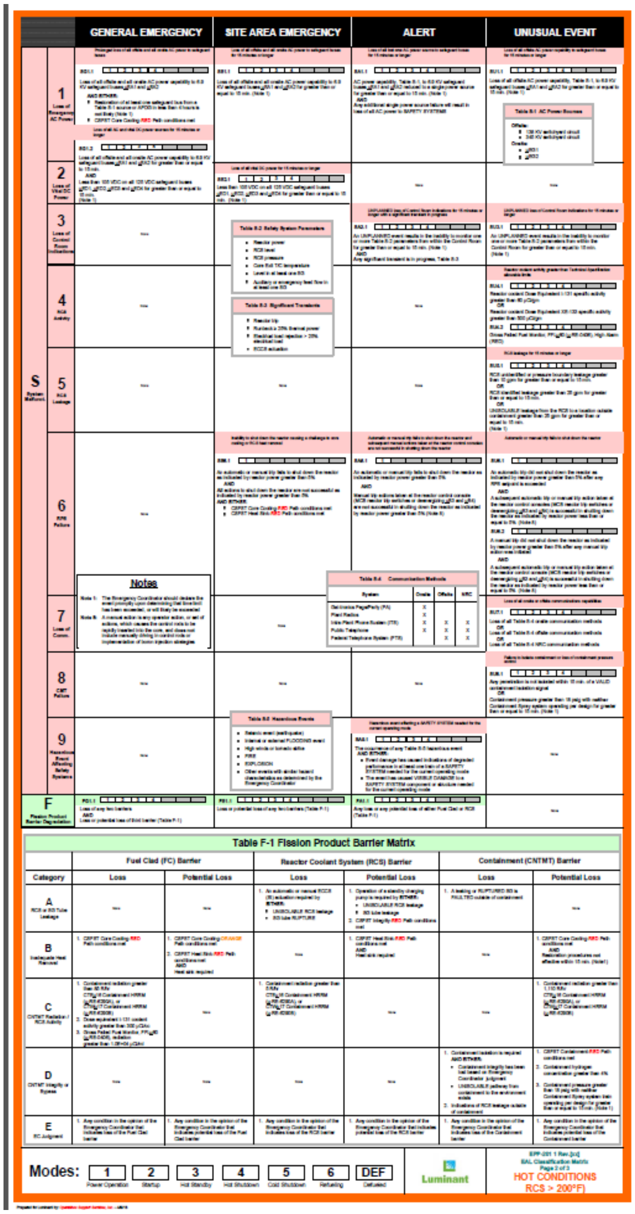
Attachment 2
EAL Classification Matrix
Page 1 of 2

The following EAL Classification Matrix is an example only. There are larger versions of EAL Classification Matrix, which are color coded to help in the determination of the classifications in the Control Room, Technical Support Center, Emergency Operations Facility and selected other locations.

EXAMPLE

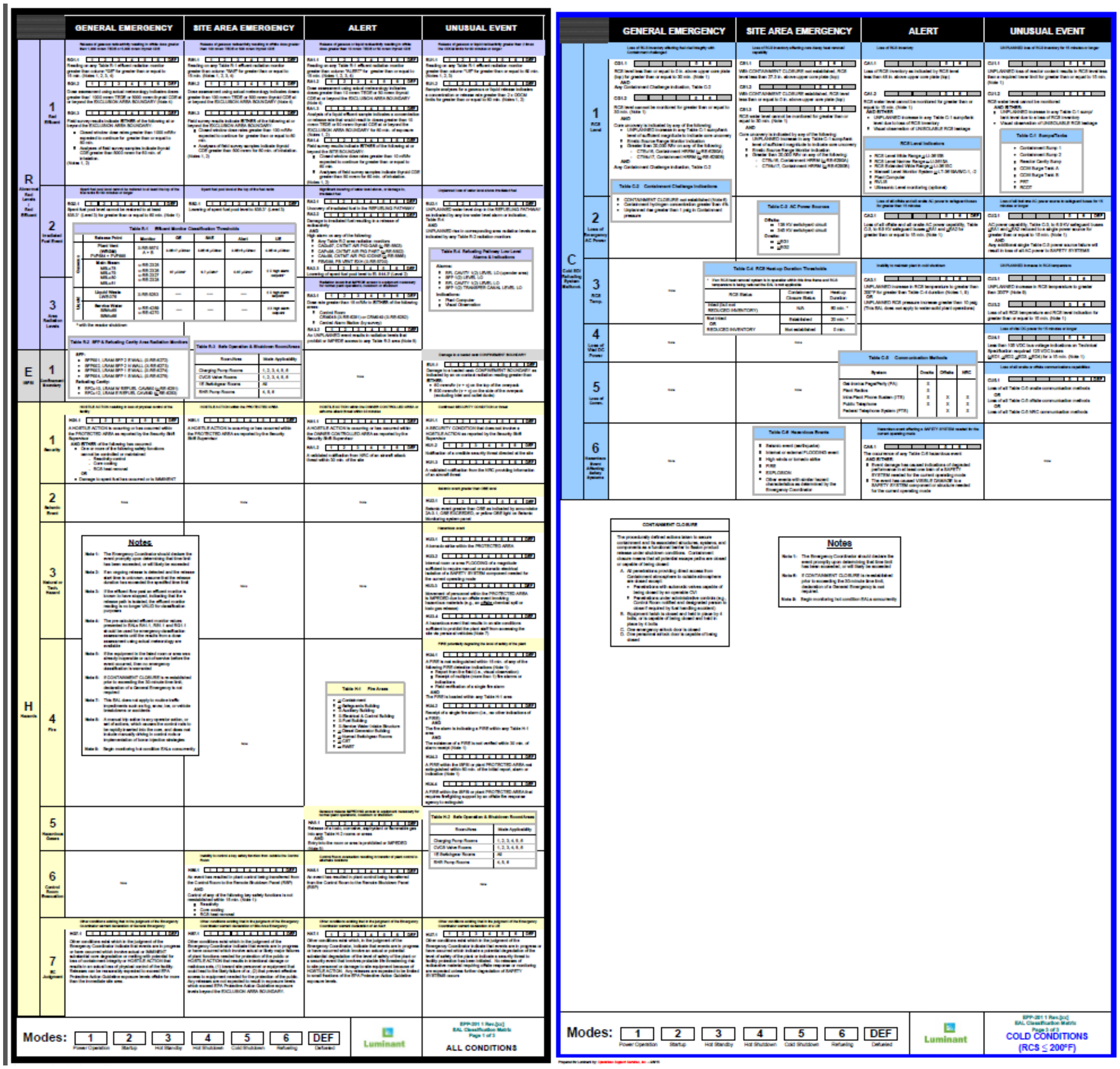
All Modes / Hot Conditions





Attachment 2
EAL Classification Matrix
Page 2 of 2

EXAMPLE
All Modes / Cold Conditions



The EAL Technical Bases Document is a stand alone document that provides an explanation and rationale for each Emergency Action Level (EAL). Decision-makers responsible for implementation of EPP-201, "Assessment of Emergency Action Levels, Emergency Classification and Plan Activation," may use this document as a technical reference in support of EAL interpretation. This information may assist the Emergency Coordinator in making classifications, particularly those involving judgment or multiple events. Below is the "Table of Contents" for the EAL Technical Bases Document

Section

Record of Changes (For Information Only)		
Rev / PCN	Affected Pages	Description of Change
13	2	Revised definition for Alert to include security/hostile action (consistent with definitions in the Emergency Plan and NEI 99-01 Rev. 6 Technical Bases Document) Added definition for Initiating Condition (IC)
13	2	Revised definition for General Emergency to include security/hostile action (consistent with definitions in the Emergency Plan and NEI 99-01 Rev. 6 Technical Bases Document) Revised definition for Site Area Emergency to include security/hostile action (consistent with definitions in the Emergency Plan and NEI 99-01 Rev. 6 Technical Bases Document) Revised definition for Unusual Event to include security/hostile action (consistent with definitions in the Emergency Plan and NEI 99-01 Rev. 6 Technical Bases Document)
13	5	Revised EAL Groups, Categories and Subcategories table to be consistent with NEI 99-01 Rev. 6 Any Operating Mode: R – Abnormal Rad Levels / Rad Effluent 1. Rad Effluent 2. Irradiated Fuel Event 3. Area Radiation Levels E – ISFSI 1. Confinement Boundary H – Hazards 1. Security 2. Seismic Event 3. Natural or Tech. Hazard 4. Fire 5. Hazardous Gases 6. Control Room Evacuation 7. EC Judgment

13	5	Hot Conditions: S – System Malfunction 1. Loss of Emergency AC Power 2. Loss of Vital DC Power 3. Loss of Control Room Indications 4. RCS Activity 5. RCS Leakage 6. RPS Failure 7. Loss of Communications 8. CMT Failure Hazardous Event Affecting Safety Systems Cold Conditions: C – Cold Shutdown / Refueling System Malfunction 1. RCS Level 2. Loss of Emergency AC Power 3. RCS Temperature 4. Loss of Vital DC Power 5. Loss of Communications 6. Hazardous Event Affecting Safety Systems
13	7	Section 4.2.2.5 - Changed 4000 R/hr to 1110 R/hr AND deleted reference to FU1.1
13	8	Added new section 4.2.4.2 which includes information about downgrading
13	9	Corrected typo “Manger” to “Manager”
13	11	Reference 5.6 changed to Rev. 6
13	12 & 13	Revised Attachment 1 Initiating Condition Table to reflect the Initiating Conditions in NEI 99-01 Rev. 6
13	14 & 15	Included examples of the NEI 99-01 Rev. 6 EAL Classification Matrices
13	16	Revised Attachment 3, EAL Technical Bases Document, to reflect the NEI 99-01 Rev. Table of Contents

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS __________ / ______

LATEST PCN/EFFECTIVE DATE: ___ / _______

LEVEL OF USE:
INFORMATION USE

Luminant

Comanche Peak Nuclear Power Plant
EPP-201
Emergency Action Level Technical Bases Document

	Print Name	Signature	Date
Prepared by:	Kelly Faver	Kelly Faver	11/16/2016
Technical Reviewer:	Gary Wiechering	[signature]	11/17/16
Reviewer:	Jeffrey Hull	Jeffrey D Hull	11/17/2016
Approval:	John Dreyfuss	[signature]	12/8/16

Effective Date: 06 – January - 2017

TABLE OF CONTENTS

1.0 PURPOSE

This document provides an explanation and rationale for each Emergency Action Level (EAL) included in the EAL Upgrade Project for Comanche Peak Nuclear Power Plant (CPNPP). Decision-makers responsible for implementation of EPP-201, "Assessment of Emergency Action Levels, Emergency Classification and Plan Activation," may use this document as a technical reference in support of EAL interpretation. This information may assist the Emergency Coordinator in making classifications, particularly those involving judgment or multiple events. The basis information may also be useful in training and for explaining event classifications to off-site officials.

The expectation is that emergency classifications are to be made as soon as conditions are present and recognizable for the classification, but within 15 minutes or less in all cases of conditions present. Use of this document for assistance is not intended to delay the emergency classification.

Because the information in a basis document can affect emergency classification decision-making (e.g., the Emergency Coordinator refers to it during an event), the NRC staff expects that changes to the basis document will be evaluated in accordance with the provisions of 10 CFR 50.54(q).

2.0 DISCUSSION

2.1 Background

EALs are the plant-specific indications, conditions or instrument readings that are utilized to classify emergency conditions defined in the CPNPP Plant Radiological Emergency Response Plan (RERP).

In 1992, the NRC endorsed NUMARC/NESP-007 "Methodology for Development of Emergency Action Levels" as an alternative to NUREG-0654 EAL guidance.

NEI 99-01 (NUMARC/NESP-007) Revisions 4 and 5 were subsequently issued for industry implementation. Enhancements over earlier revisions included:

- Consolidating the system malfunction initiating conditions and example emergency action levels which address conditions that may be postulated to occur during plant shutdown conditions.
- Initiating conditions and example emergency action levels that fully address conditions that may be postulated to occur at permanently Defueled Stations and Independent Spent Fuel Storage Installations (ISFSIs).
- Simplifying the fission product barrier EAL threshold for a Site Area Emergency.

Subsequently, Revision 6 of NEI 99-01 has been issued which incorporates resolutions to numerous implementation issues including the NRC EAL Frequently Asked Questions (FAQs). Using NEI 99-01 Revision 6, "Methodology for the Development of Emergency Action Levels for Non-Passive Reactors," November 2012 (ADAMS Accession Number ML12326A805) (ref. 4.1.1), CPNPP conducted an EAL implementation upgrade project that produced the EALs discussed herein

2.2 Fission Product Barriers

Fission product barrier thresholds represent threats to the defense in depth design concept that precludes the release of radioactive fission products to the environment. This concept relies on multiple physical barriers, any one of which, if maintained intact, precludes the release of significant amounts of radioactive fission products to the environment.

Many of the EALs derived from the NEI methodology are fission product barrier threshold based. That is, the conditions that define the EALs are based upon thresholds that represent the loss or potential loss of one or more of the three fission product barriers. “Loss” and “Potential Loss” signify the relative damage and threat of damage to the barrier. A “Loss” threshold means the barrier no longer assures containment of radioactive materials. A “Potential Loss” threshold implies an increased probability of barrier loss and decreased certainty of maintaining the barrier.

The primary fission product barriers are:

A. <u>Fuel Clad (FC):</u> The Fuel Clad Barrier consists of the cladding material that contains the fuel pellets.

B. <u>Reactor Coolant System (RCS):</u> The RCS Barrier includes the RCS primary side and its connections up to and including the pressurizer safety and relief valves, and other connections up to and including the primary isolation valves.

C. <u>Containment (CNTMT):</u> The Containment Barrier includes the containment building and connections up to and including the outermost containment isolation valves. This barrier also includes the main steam, feedwater, and blowdown line extensions outside the containment building up to and including the outermost secondary side isolation valve. Containment Barrier thresholds are used as criteria for escalation of the ECL from Alert to a Site Area Emergency or a General Emergency

2.3 Fission Product Barrier Classification Criteria

The following criteria are the bases for event classification related to fission product barrier loss or potential loss:

<u>Alert:</u>

Any loss or any potential loss of either Fuel Clad or RCS barrier

<u>Site Area Emergency:</u>

Loss or potential loss of any two barriers

<u>General Emergency:</u>

Loss of any two barriers and loss or potential loss of the third barrier

2.4 EAL Organization

The CPNPP EAL scheme includes the following features:

- Division of the EAL set into three broad groups:
    - EALs applicable under <u>any</u> plant operating modes – This group would be reviewed by the EAL-user any time emergency classification is considered.
    - EALs applicable only under <u>hot</u> operating modes – This group would only be reviewed by the EAL-user when the plant is in Hot Shutdown, Hot Standby, Startup, or Power Operation mode.
    - EALs applicable only under <u>cold</u> operating modes – This group would only be reviewed by the EAL-user when the plant is in Cold Shutdown, Refueling or Defueled mode.

  The purpose of the groups is to avoid review of hot condition EALs when the plant is in a cold condition and avoid review of cold condition EALs when the plant is in a hot condition. This approach significantly minimizes the total number of EALs that must be reviewed by the EAL-user for a given plant condition, reduces EAL-user reading burden and, thereby, speeds identification of the EAL that applies to the emergency.

- Within each group, assignment of EALs to categories and subcategories:

Category and subcategory titles are selected to represent conditions that are operationally significant to the EAL-user. The CPNPP EAL categories are aligned to and represent the NEI 99-01"Recognition Categories." Subcategories are used in the CPNPP scheme as necessary to further divide the EALs of a category into logical sets of possible emergency classification thresholds. The CPNPP EAL categories and subcategories are listed below.

EAL Groups, Categories and Subcategories

EAL Group/Category	EAL Subcategory
Any Operating Mode:	
R – Abnormal **R**ad Levels / Rad Effluent	1 – Radiological Effluent 2 – **I**rradiated Fuel Event 3 – Area Radiation Levels
H – **H**azards and Other Conditions Affecting Plant Safety	1 – Security 2 – Seismic Event 3 – Natural or Technological Hazard 4 – Fire 5 – Hazardous Gases 6 – Control Room Evacuation 7 – Emergency Coordinator Judgment
E – ISFSI	1 – Confinement Boundary
Hot Conditions:	
S – **S**ystem Malfunction	1 – Loss of Emergency AC Power 2 – Loss of Vital DC Power 3 – Loss of Control Room Indications 4 – RCS Activity 5 – RCS Leakage 6 – RPS Failure 7 – Loss of Communications 8 – Containment Failure 9 – Hazardous Event Affecting Safety Systems
F – **F**ission Product Barrier Degradation	None
Cold Conditions:	
C – **C**old Shutdown / Refueling System Malfunction	1 – RCS Level 2 – Loss of Emergency AC Power 3 – RCS Temperature 4 – Loss of Vital DC Power 5 – Loss of Communications 6 – Hazardous Event Affecting Safety Systems

The primary tool for determining the emergency classification level is the EAL Classification Matrix. The user of the EAL Classification Matrix may (but is not required to) consult the EAL Technical Bases Document in order to obtain additional information concerning the EALs under classification consideration. The user should consult Section 3.0 and Attachments 1 & 2 of this document for such information.

2.5 Technical Bases Information

EAL technical bases are provided in Attachment 1 for each EAL according to EAL group (Any, Hot, Cold), EAL category (R, C, H, S, E and F) and EAL subcategory. A summary explanation of each category and subcategory is given at the beginning of the technical bases discussions of the EALs included in the category. For each EAL, the following information is provided:

Category Letter & Title

Subcategory Number & Title

Initiating Condition (IC)

Site-specific description of the generic IC given in NEI 99-01 Rev. 6.

EAL Identifier (enclosed in rectangle)

Each EAL is assigned a unique identifier to support accurate communication of the emergency classification to onsite and offsite personnel. Four characters define each EAL identifier:

1. First character (letter): Corresponds to the EAL category as described above (R, C, H, S, E or F)
2. Second character (letter): The emergency classification (G, S, A or U)

   G = General Emergency
   S = Site Area Emergency
   A = Alert
   U = Unusual Event

3. Third character (number): Subcategory number within the given category. Subcategories are sequentially numbered beginning with the number one (1). If a category does not have a subcategory, this character is assigned the number one (1).
4. Fourth character (number): The numerical sequence of the EAL within the EAL subcategory. If the subcategory has only one EAL, it is given the number one (1).

Classification (enclosed in rectangle):

Unusual Event (U), Alert (A), Site Area Emergency (S) or General Emergency (G)

EAL (enclosed in rectangle)

Exact wording of the EAL as it appears in the EAL Classification Matrix

Mode Applicability

One or more of the following plant operating conditions comprise the mode to which each EAL is applicable: 1 - Power Operation, 2 - Startup, 3 – Hot Standby, 4 - Hot Shutdown, 5 - Cold Shutdown, 6 - Refueling, D - Defueled, or Any. (See Section 2.6 for operating mode definitions)

Definitions:

If the EAL wording contains a defined term, the definition of the term is included in this section. These definitions can also be found in Section 5.1.

Basis:

A basis section that provides CPNPP-relevant information concerning the EALas well as a description of the rationale for the EAL as provided in NEI 99-01 Rev. 6.

CPNPP Basis Reference(s):

Site-specific source documentation from which the EAL is derived.

2.6 Operating Mode Applicability (ref. 4.1.8)

1 Power Operation
K_{eff} greater than or equal to 0.99 and reactor thermal power greater than 5%

2 Startup
K_{eff} greater than or equal to 0.99 and reactor thermal power ≤ 5%

3 Hot Standby
K_{eff} less than 0.99 and average coolant temperature greater than or equal to 350ºF

4 Hot Shutdown
K_{eff} less than 0.99 and average coolant temperature 350ºF greater than T_{avg} greater than 200 ºF and all reactor vessel head closure bolts fully tensioned

5 Cold Shutdown
K_{eff} less than 0.99 and average coolant temperature ≤ 200ºF

6 Refueling
One or more reactor vessel head closure bolts are less than fully tensioned

D Defueled
All reactor fuel removed from reactor pressure vessel (full core off load during refueling or extended outage).

The plant operating mode that exists at the time that the event occurs (prior to any protective system or operator action being initiated in response to the condition) should be compared to the mode applicability of the EALs. If a lower or higher plant operating mode is reached before the emergency classification is made, the declaration shall be based on the mode that existed at the time the event occurred.

2.7 Unit Designation

The specific unit designator (1 or 2) is represented within these instructions by the symbol "u". The appropriate unit digit may be substituted for this symbol to obtain the unit specific equipment number (Example *u*-FK-121 represents 1-FK-121 for Unit 1 and 2-FK-121 for Unit 2). For equipment or components that are common or non unit-specific the “X” designator is used. (Example *X*-RE-6272 represents a radiation monitor that is common to both units).

3.0 GUIDANCE ON MAKING EMERGENCY CLASSIFICATIONS

3.1 General Considerations

When making an emergency classification, the Emergency Coordinator must consider all information having a bearing on the proper assessment of an Initiating Condition (IC). This includes the Emergency Action Level (EAL) plus the associated Operating Mode Applicability, Notes, and the informing basis information. In the Recognition Category F matrices, EALs are based on loss or potential loss of Fission Product Barrier Thresholds.

3.1.1 Classification Timeliness

NRC regulations require the licensee to establish and maintain the capability to assess, classify, and declare an emergency condition within 15 minutes after the availability of indications to plant operators that an emergency action level has been exceeded and to promptly declare the emergency condition as soon as possible following identification of the appropriate emergency classification level. The NRC staff has provided guidance on implementing this requirement in NSIR/DPR-ISG-01, "Interim Staff Guidance, Emergency Planning for Nuclear Power Plants" (ref. 4.1.11).

3.1.2 Valid Indications

All emergency classification assessments shall be based upon valid indications, reports or conditions. A valid indication, report, or condition, is one that has been verified through appropriate means such that there is no doubt regarding the indicator's operability, the condition's existence, or the report's accuracy. For example, verification could be accomplished through an instrument channel check, response on related or redundant indicators, or direct observation by plant personnel.

An indication, report, or condition is considered to be valid when it is verified by (1) an instrument channel check, or (2) indications on related or redundant indicators, or (3) by direct observation by plant personnel, such that doubt related to the indicator's operability, the condition's existence, or the report's accuracy is removed. Implicit in this definition is the need for timely assessment.

3.1.3 Imminent Conditions

For ICs and EALs that have a stipulated time duration (e.g., 15 minutes, 30 minutes, etc.), the Emergency Coordinator should not wait until the applicable time has elapsed, but should declare the event as soon as it is determined that the condition has exceeded, or will likely exceed, the applicable time. If an ongoing radiological release is detected and the release start time is unknown, it should be assumed that the release duration specified in the IC/EAL has been exceeded, absent data to the contrary.

3.1.4 Planned vs. Unplanned Events

A planned work activity that results in an expected event or condition which meets or exceeds an EAL does not warrant an emergency declaration provided that: 1) the activity proceeds as planned, and 2) the plant remains within the limits imposed by the operating license. Such activities include planned work to test, manipulate, repair, maintain or modify a system or component. In these cases, the controls associated with the planning, preparation and execution of the work will ensure that compliance is maintained with all aspects of the operating license provided that the activity proceeds and concludes as expected. Events or conditions of this type may be subject to the reporting requirements of 10 § CFR 50.72 (ref. 4.1.4).

3.1.5 Classification Based on Analysis

The assessment of some EALs is based on the results of analyses that are necessary to ascertain whether a specific EAL threshold has been exceeded (e.g., dose assessments, chemistry sampling, RCS leak rate calculation, etc.). For these EALs, the EAL wording or the associated basis discussion will identify the necessary analysis. In these cases, the 15-minute declaration period starts with the availability of the analysis results that show the threshold to be exceeded (i.e., this is the time that the EAL information is first available). The NRC expects licensees to establish the capability to initiate and complete EAL-related analyses within a reasonable period of time (e.g., maintain the necessary expertise on-shift).

3.1.6 Emergency Coordinator Judgment

While the EALs have been developed to address a full spectrum of possible events and conditions which may warrant emergency classification, a provision for classification based on operator/management experience and judgment is still necessary. The NEI 99-01 EAL scheme provides the Emergency Coordinator with the ability to classify events and conditions based upon judgment using EALs that are consistent with the Emergency Classification Level (ECL) definitions (refer to Category H). The Emergency Coordinator will need to determine if the effects or consequences of the event or condition reasonably meet or exceed a particular ECL definition. A similar provision is incorporated in the Fission Product Barrier Tables; judgment may be used to determine the status of a fission product barrier.

3.2 Classification Methodology

To make an emergency classification, the user will compare an event or condition (i.e., the relevant plant indications and reports) to an EAL(s) and determine if the EAL has been met or exceeded. The evaluation of an EAL must be consistent with the related Operating Mode Applicability and Notes. If an EAL has been met or exceeded, the associated IC is likewise met, the emergency classification process “clock” starts, and the ECL must be declared in accordance with plant procedures no later than fifteen minutes after the process “clock” started.

When assessing an EAL that specifies a time duration for the off-normal condition, the “clock” for the EAL time duration runs concurrently with the emergency classification process “clock.” For a full discussion of this timing requirement, refer to NSIR/DPR-ISG-01 (ref. 4.1.11).

3.2.1 Classification of Multiple Events and Conditions

When multiple emergency events or conditions are present, the user will identify all met or exceeded EALs. The highest applicable ECL identified during this review is declared. For example:

- If an Alert EAL and a Site Area Emergency EAL are met, whether at one unit or at two different units, a Site Area Emergency should be declared.

There is no “additive” effect from multiple EALs meeting the same ECL. For example:

- If two Alert EALs are met, whether at one unit or at two different units, an Alert should be declared.

Related guidance concerning classification of rapidly escalating events or conditions is provided in Regulatory Issue Summary (RIS) 2007-02, *Clarification of NRC Guidance for Emergency Notifications During Quickly Changing Events* (ref. 4.1.2).

3.2.2 Consideration of Mode Changes During Classification

The mode in effect at the time that an event or condition occurred, and prior to any plant or operator response, is the mode that determines whether or not an IC is applicable. If an event or condition occurs, and results in a mode change before the emergency is declared, the emergency classification level is still based on the mode that existed at the time that the event or condition was initiated (and not when it was declared). Once a different mode is reached, any new event or condition, not related to the original event or condition, requiring emergency classification should be evaluated against the ICs and EALs applicable to the operating mode at the time of the new event or condition.

For events that occur in Cold Shutdown or Refueling, escalation is via EALs that are applicable in the Cold Shutdown or Refueling modes, even if Hot Shutdown (or a higher mode) is entered during the subsequent plant response. In particular, the fission product barrier EALs are applicable only to events that initiate in the Hot Shutdown mode or higher.

3.2.3 Classification of Imminent Conditions

Although EALs provide specific thresholds, the Emergency Coordinator must remain alert to events or conditions that could lead to meeting or exceeding an EAL within a relatively short period of time (i.e., a change in the ECL is IMMINENT). If, in the judgment of the Emergency Coordinator, meeting an EAL is IMMINENT, the emergency classification should be made as if the EAL has been met. While applicable to all emergency classification levels, this approach is particularly important at the higher emergency classification levels since it provides additional time for implementation of protective measures.

3.2.4 Emergency Classification Level Upgrading and Downgrading

An ECL may be downgraded when the event or condition that meets the highest IC and EAL no longer exists, and other site-specific downgrading requirements are met. If downgrading the ECL is deemed appropriate, the new ECL would then be based on a lower applicable IC(s) and EAL(s). The ECL may also simply be terminated.

As noted above, guidance concerning classification of rapidly escalating events or conditions is provided in RIS 2007-02 (ref. 4.1.2).

3.2.5 Classification of Short-Lived Events

Event-based ICs and EALs define a variety of specific occurrences that have potential or actual safety significance. By their nature, some of these events may be short-lived and, thus, over before the emergency classification assessment can be completed. If an event occurs that meets or exceeds an EAL, the associated ECL must be declared regardless of its continued presence at the time of declaration. Examples of such events include an earthquake or a failure of the reactor protection system to automatically trip the reactor followed by a successful manual trip.

3.2.6 Classification of Transient Conditions

Many of the ICs and/or EALs employ time-based criteria. These criteria will require that the IC/EAL conditions be present for a defined period of time before an emergency declaration is warranted. In cases where no time-based criterion is specified, it is recognized that some transient conditions may cause an EAL to be met for a brief period of time (e.g., a few seconds to a few minutes). The following guidance should be applied to the classification of these conditions.

EAL momentarily met during expected plant response - In instances where an EAL is briefly met during an expected (normal) plant response, an emergency declaration is not warranted provided that associated systems and components are operating as expected, and operator actions are performed in accordance with procedures.

EAL momentarily met but the condition is corrected prior to an emergency declaration – If an operator takes prompt manual action to address a condition, and the action is successful in correcting the condition prior to the emergency declaration, then the applicable EAL is not considered met and the associated emergency declaration is not required. For illustrative purposes, consider the following example:

> An ATWS occurs and the high pressure ECCS systems fail to automatically start. RPV level rapidly decreases and the plant enters an inadequate core cooling condition (a potential loss of both the fuel clad and RCS barriers). If an operator manually starts a high pressure ECCS system in accordance with an EOP step and clears the inadequate core cooling condition prior to an emergency declaration, then the classification should be based on the ATWS only.

It is important to stress that the 15-minute emergency classification assessment period (process clock) is not a “grace period” during which a classification may be delayed to allow the performance of a corrective action that would obviate the need to classify the event. Emergency classification assessments must be deliberate and timely, with no undue delays. The provision discussed above addresses only those rapidly evolving situations when an operator is able to take a successful corrective action prior to the Emergency Coordinator completing the review and steps necessary to make the emergency declaration. This provision is included to ensure that any public protective actions resulting from the emergency classification are truly warranted by the plant conditions.

3.2.7 After-the-Fact Discovery of an Emergency Event or Condition

In some cases, an EAL may be met but the emergency classification was not made at the time of the event or condition. This situation can occur when personnel discover that an event or condition existed which met an EAL, but no emergency was declared, and the event or condition no longer exists at the time of discovery. This may be due to the event or condition not being recognized at the time or an error that was made in the emergency classification process.

In these cases, no emergency declaration is warranted; however, the guidance contained in NUREG-1022 (ref. 4.1.3) is applicable. Specifically, the event should be reported to the NRC in accordance with 10 CFR § 50.72 (ref. 4.1.4) within one hour of the discovery of the undeclared event or condition. The licensee should also notify appropriate State and local agencies in accordance with the agreed upon arrangements.

3.2.8 Retraction of an Emergency Declaration

Guidance on the retraction of an emergency declaration reported to the NRC is discussed in NUREG-1022 (ref. 4.1.3).

4.0 REFERENCES

4.1 Developmental

4.1.1 NEI 99-01 Revision 6, Methodology for the Development of Emergency Action Levels for Non-Passive Reactors, ADAMS Accession Number ML12326A805

4.1.2 RIS 2007-02 Clarification of NRC Guidance for Emergency Notifications During Quickly Changing Events, February 2, 2007.

4.1.3 NUREG-1022 Event Reporting Guidelines: 10CFR50.72 and 50.73

4.1.4 10 § CFR 50.72 Immediate Notification Requirements for Operating Nuclear Power Reactors

4.1.5 10 § CFR 50.73 License Event Report System

4.1.6 CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area

4.1.7 CPNPP FSAR Section 2.1.1 Site Location and Description

4.1.8 Technical Specifications Table 1.1-1 Modes

4.1.9 OPT-408A/B Refueling Containment Penetration Verification

4.1.10 ODA-207 Guidelines on the Preparation and Review of Operations Procedures

4.1.11 NSIR/DPR-ISG-01 Interim Staff Guidance, Emergency Planning for Nuclear Power Plants

4.1.12 IPO-010A/B Reactor Coolant System Reduced Inventory Operations

4.1.13 Technical Specifications 3.9.4

4.1.14 CPNPP Offsite Dose Calculation Manual (ODCM)

4.2 Implementing

4.2.1 EPP-201, Assessment of Emergency Action Levels, Emergency Classification and Plan Activation

4.2.2 NEI 99-01 Rev. 6 to CPNPP EAL Comparison Matrix

4.2.3 CPNPP EAL Matrix

5.0 DEFINITIONS, ACRONYMS & ABBREVIATIONS

5.1 Definitions (ref. 4.1.1 except as noted)

Selected terms used in Initiating Condition and Emergency Action Level statements are set in all capital letters (e.g., ALL CAPS). These words are defined terms that have specific meanings as used in this document. The definitions of these terms are provided below.

Alert

Events are in progress, or have occurred, which involve an actual or potential substantial degradation of the level of safety of the plant or a security event that involves probable life threatening risk to site personnel or damage to site equipment because of hostile action. Any releases are expected to be small fractions of the EPA Protective Action Guideline exposure levels.

Confinement Boundary

The barrier(s) between spent fuel and the environment once the spent fuel is processed for dry storage. As applied to the CPNPP ISFSI, the CONFINEMENT BOUNDARY is defined to be the Multi-Purpose Canister (MPC).

Containment Closure

The procedurally defined actions taken to secure containment and its associated structures, systems, and components as a functional barrier to fission product release under shutdown conditions. Containment closure means that all potential escape paths are closed or capable of being closed (ref.4.1.13).

A. All penetrations providing direct access from Containment atmosphere to outside atmosphere are closed except:
   - Penetrations with automatic valves capable of being closed by an operable CVI
   - Penetrations under administrative controls (e.g., Control Room notified and designated person to close if required by fuel handling accident)
B. Equipment hatch is closed and held in place by 4 bolts, or is capable of being closed and held in place by 4 bolts
C. One emergency airlock door is closed
D. One personnel airlock door is capable of being closed (ref. 4.1.9)

Emergency Action Level

A pre-determined, site-specific, observable threshold for an Initiating Condition that, when met or exceeded, places the plant in a given emergency classification level.

Emergency Classification Level

One of a set of names or titles established by the US Nuclear Regulatory Commission (NRC) for grouping off-normal events or conditions according to (1) potential or actual effects or consequences, and (2) resulting onsite and offsite response actions. The emergency classification levels, in ascending order of severity, are: Unusual Event (UE), Alert, Site Area Emergency (SAE) and General Emergency (GE).

EPA PAGs

Environment Protection Agency Protective Action Guidelines. The EPA PAGs are expressed in terms of dose commitment: 1 Rem TEDE or 5 Rem CDE Thyroid. Actual or projected offsite exposures in excess of the EPA PAGs requires CPNPP to recommend protective actions for the general public to offsite planning agencies.

Exclusion Area Boundary

Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20 (ref. 4.1.7). See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area (ref. 4.1.6) and CPNPP ODCM Section 5.0 Design Features (ref. 4.1.14).

Explosion

A rapid, violent and catastrophic failure of a piece of equipment due to combustion, chemical reaction or overpressurization. A release of steam (from high energy lines or components) or an electrical component failure (caused by short circuits, grounding, arcing, etc.) should not automatically be considered an explosion. Such events require a post-event inspection to determine if the attributes of an explosion are present.

Faulted

The term applied to a steam generator that has a steam leak on the secondary side of sufficient size to cause an uncontrolled drop in steam generator pressure or the steam generator to become completely depressurized.

Fire

Combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is NOT required if large quantities of smoke and heat are observed.

Fission Product Barrier Threshold

A pre-determined, site-specific, observable threshold indicating the loss or potential loss of a fission product barrier.

Flooding

A condition where water is entering a room or area faster than installed equipment is capable of removal, resulting in a rise of water level within the room or area.

General Emergency

Events are in progress or have occurred which involve actual or imminent substantial core degradation or melting with potential for loss of containment integrity or hostile actions that result in an actual loss of physical control of the facility. Releases can be reasonably expected to exceed EPA Protective Action Guideline exposure levels offsite for more than the immediate site area.

Hostage

A person(s) held as leverage against the station to ensure that demands will be met by the station.

Hostile Action

An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area).

Hostile Force

One or more individuals who are engaged in a determined assault, overtly or by stealth and deception, equipped with suitable weapons capable of killing, maiming, or causing destruction.

Imminent

The trajectory of events or conditions is such that an EAL will be met within a relatively short period of time regardless of mitigation or corrective actions.

Impede(d)

Personnel access to a room or area is hindered to an extent that extraordinary measures are necessary to facilitate entry of personnel into the affected room/area (e.g., requiring use of protective equipment, such as SCBAs, that is not routinely employed).

Independent Spent Fuel Storage Installation (ISFSI)

A complex that is designed and constructed for the interim storage of spent nuclear fuel and other radioactive materials associated with spent fuel storage.

Initiating Condition

An event or condition that aligns with the definition of one of the four emergency classification levels by virtue of the potential or actual effects or consequences.

Maintain

Take appropriate action to hold the value of an identified parameter within specified limits.

Owner Controlled Area

As shown in CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area.

Projectile

An object directed toward a Nuclear Power Plant that could cause concern for its continued operability, reliability, or personnel safety.

Protected Area

An area encompassed by physical barriers and to which access is controlled. The Protected Area refers to the designated security area around the process buildings and is depicted in FSAR Figure 1.2-1 Plot Plan (ref. 4.1.7).

RCS Intact

The RCS should be considered intact when the RCS pressure boundary is in its normal condition for the cold shutdown mode of operation (e.g., no freeze seals or nozzle dams).

Reduced Inventory

Plant condition when fuel is in the reactor vessel and Reactor Coolant System level is ≤ 80 inches above core plate (829'8") (ref. 4.1.12).

Refueling Pathway

The reactor refueling cavity, spent fuel pool and fuel transfer canal comprise the refueling pathway.

Ruptured

The condition of a steam generator in which primary-to-secondary leakage is of sufficient magnitude to require a safety injection.

Restore

Take the appropriate action required to return the value of an identified parameter to the applicable limits.

Safety System

A system required for safe plant operation, cooling down the plant and/or placing it in the cold shutdown condition, including the ECCS. These are typically systems classified as safety-related (as defined in 10CFR50.2):

Those structures, systems and components that are relied upon to remain functional during and following design basis events to assure:

(1) The integrity of the reactor coolant pressure boundary;

(2) The capability to shut down the reactor and maintain it in a safe shutdown condition;

(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures.

Security Condition

Any security event as listed in the approved security contingency plan that constitutes a threat/compromise to site security, threat/risk to site personnel, or a potential degradation to the level of safety of the plant. A security condition does not involve a hostile action.

Site Area Emergency

Events are in progress or have occurred which involve actual or likely major failures of plant functions needed for protection of the public or hostile actions that result in intentional damage or malicious acts; (1) toward site personnel or equipment that could lead to the likely failure of or; (2) that prevent effective access to equipment needed for the protection of the public. Any releases are not expected to result in exposure levels which exceed EPA Protective Action Guidelines exposure levels beyond the site boundary.

Site Boundary

See EXCLUSION AREA BOUNDARY

Unisolable

An open or breached system line that cannot be isolated, remotely or locally.

Unplanned

A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Unusual Event

Events are in progress or have occurred which indicate a potential degradation in the level of safety of the plant or indicate a security threat to facility protection has been initiated. No releases of radioactive material requiring offsite response or monitoring are expected unless further degradation of safety systems occurs.

Valid

An indication, report, or condition, is considered to be valid when it is verified by (1) an instrument channel check, or (2) indications on related or redundant indicators, or (3) by direct observation by plant personnel, such that doubt related to the indicator's operability, the condition's existence, or the report's accuracy is removed. Implicit in this definition is the need for timely assessment.

Visible Damage

Damage to a component or structure that is readily observable without measurements, testing, or analysis. The visual impact of the damage is sufficient to cause concern regarding the operability or reliability of the affected component or structure.

5.2 Abbreviations/Acronyms

°F .... Degrees Fahrenheit
° .... Degrees
AC .... Alternating Current
APDG .... Alternate Power Diesel Generator
ATWS .... Anticipated Transient Without Scram
CPNPP .... Comanche Peak Nuclear Power Plant
CDE .... Committed Dose Equivalent
CFR .... Code of Federal Regulations
CNTMT .... Containment
CSFST .... Critical Safety Function Status Tree
DBA .... Design Basis Accident
DC .... Direct Current
EAL .... Emergency Action Level
ECCS .... Emergency Core Cooling System
ECL .... Emergency Classification Level
EOF .... Emergency Operations Facility
EOP .... Emergency Operating Procedure
EPA .... Environmental Protection Agency
ERG .... Emergency Response Guideline
EPIP .... Emergency Plan Implementing Procedure
ESF .... Engineered Safety Feature
ESW .... Emergency Service Water
FAA .... Federal Aviation Administration
FBI .... Federal Bureau of Investigation
FEMA .... Federal Emergency Management Agency
FSAR .... Final Safety Analysis Report
GE .... General Emergency
IC .... Initiating Condition
IPEEE .... Individual Plant Examination of External Events (Generic Letter 88-20)
K_{eff} .... Effective Neutron Multiplication Factor
LCO .... Limiting Condition of Operation
LER .... Licensee Event Report
LOCA .... Loss of Coolant Accident
LWR .... Light Water Reactor
MPC .... Maximum Permissible Concentration/Multi-Purpose Canister
mR, mRem, mrem, mREM .... milli-Roentgen Equivalent Man
MSL .... Main Steam Line
MW .... Megawatt
NEI .... Nuclear Energy Institute

NESP...National Environmental Studies Project
NPP .... Nuclear Power Plant
NRC...Nuclear Regulatory Commission
NSSS... Nuclear Steam Supply System
NORAD...North American Aerospace Defense Command
(NO)UE..Notification of Unusual Event
OBE .... Operating Basis Earthquake
OCA..Owner Controlled Area
ODCM..Off-site Dose Calculation Manual
ORO .... Offsite Response Organization
OTO... Off-Normal Operating Procedure
PA.. Protected Area
PAG .... Protective Action Guideline
PRA/PSA..................... Probabilistic Risk Assessment / Probabilistic Safety Assessment
PWR .... Pressurized Water Reactor
PSIG...Pounds per Square Inch Gauge
R.. Roentgen
RCC.. Reactor Control Console
RCS .... Reactor Coolant System
Rem, rem, REM ....Roentgen Equivalent Man
RETS .... Radiological Effluent Technical Specifications
RPS .... Reactor Protection System
R(P)V... Reactor (Pressure) Vessel
RVLIS .... Reactor Vessel Level Indicating System
SAR .... Safety Analysis Report
SBO .... Station Blackout
SCBA... Self-Contained Breathing Apparatus
SG .... Steam Generator
SI .... Safety Injection
ODCM...Offsite Dose Calculation Manual
SPDS.. Safety Parameter Display System
SRO... Senior Reactor Operator
TEDE .... Total Effective Dose Equivalent
TOAF .... Top of Active Fuel
TSC .... Technical Support Center
WOG.. Westinghouse Owners Group

6.0 CPNPP-TO-NEI 99-01 Rev. 6 EAL CROSS-REFERENCE

This cross-reference is provided to facilitate association and location of a CPNPP EAL within the NEI 99-01 IC/EAL identification scheme. Further information regarding the development of the CPNPP EALs based on the NEI guidance can be found in the EAL Comparison Matrix.

CPNPP	NEI 99-01 Rev. 6	
EAL	**IC**	**Example EAL**
RU1.1	AU1	1, 2
RU1.2	AU1	3
RU2.1	AU2	1
RA1.1	AA1	1
RA1.2	AA1	2
RA1.3	AA1	3
RA1.4	AA1	4
RA2.1	AA2	1
RA2.2	AA2	2
RA2.3	AA2	3
RA3.1	AA3	1
RA3.2	AA3	2
RS1.1	AS1	1
RS1.2	AS1	2
RS1.3	AS1	3
RS2.1	AS2	1
RG1.1	AG1	1
RG1.2	AG1	2
RG1.3	AG1	3
RG2.1	AG2	1
CU1.1	CU1	1

CPNPP	NEI 99-01 Rev. 6	
EAL	**IC**	**Example EAL**
CU1.2	CU1	2
CU2.1	CU2	1
CU3.1	CU3	1
CU3.2	CU3	2
CU4.1	CU4	1
CU5.1	CU5	1, 2, 3
CA1.1	CA1	1
CA1.2	CA1	2
CA2.1	CA2	1
CA3.1	CA3	1, 2
CA6.1	CA6	1
CS1.1	CS1	1
CS1.2	CS1	2
CS1.3	CS1	3
CG1.1	CG1	2
FA1.1	FA1	1
FS1.1	FS1	1
FG1.1	FG1	1
HU1.1	HU1	1
HU1.2	HU1	2
HU1.3	HU1	3
HU2.1	HU2	1
HU3.1	HU3	1
HU3.2	HU3	2
HU3.3	HU3	3

CPNPP	NEI 99-01 Rev. 6	
EAL	**IC**	**Example EAL**
HU3.4	HU3	4
HU4.1	HU4	1
HU4.2	HU4	2
HU4.3	HU4	3
HU4.4	HU4	4
HU7.1	HU7	1
HA1.1	HA1	1
HA1.2	HA1	2
HA5.1	HA5	1
HA6.1	HA6	1
HA7.1	HA7	1
HS1.1	HS1	1
HS6.1	HS6	1
HS7.1	HS7	1
HG1.1	HG1	1
HG7.1	HG7	1
SU1.1	SU1	1
SU3.1	SU2	1
SU4.1	SU3	1
SU4.2	SU3	2
SU5.1	SU4	1, 2, 3
SU6.1	SU5	1
SU6.2	SU5	2
SU7.1	SU6	1, 2, 3
SU8.1	SU7	1

CPNPP	NEI 99-01 Rev. 6	
EAL	IC	Example EAL
SA1.1	SA1	1
SA3.1	SA2	1
SA6.1	SA5	1
SA9.1	SA9	1
SS1.1	SS1	1
SS2.1	SS8	1
SS6.1	SS5	1
SG1.1	SG1	1
SG1.2	SG8	1
EU1.1	E-HU1	1

7.0 ATTACHMENTS

7.1 Attachment 1, Emergency Action Level Technical Bases

7.2 Attachment 2, Fission Product Barrier Matrix and Basis

7.3 Attachment 3, Safe Operation & Shutdown Areas Tables R-3 & H-2 Bases

Category R – Abnormal Rad Release / Rad Effluent

EAL Group: ANY (EALs in this category are applicable to any plant condition, hot or cold.)

Many EALs are based on actual or potential degradation of fission product barriers because of the elevated potential for offsite radioactivity release. Degradation of fission product barriers though is not always apparent via non-radiological symptoms. Therefore, direct indication of elevated radiological effluents or area radiation levels are appropriate symptoms for emergency classification.

At lower levels, abnormal radioactivity releases may be indicative of a failure of containment systems or precursors to more significant releases. At higher release rates, offsite radiological conditions may result which require offsite protective actions. Elevated area radiation levels in plant may also be indicative of the failure of containment systems or preclude access to plant vital equipment necessary to ensure plant safety.

Events of this category pertain to the following subcategories:

1. Radiological Effluent

   Direct indication of effluent radiation monitoring systems provides a rapid assessment mechanism to determine releases in excess of classifiable limits. Projected offsite doses, actual offsite field measurements or measured release rates via sampling indicate doses or dose rates above classifiable limits.

2. Irradiated Fuel Event

   Conditions indicative of a loss of adequate shielding or damage to irradiated fuel may preclude access to vital plant areas or result in radiological releases that warrant emergency classification.

3. Area Radiation Levels

   Sustained general area radiation levels which may preclude access to areas requiring continuous occupancy also warrant emergency classification.

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous or liquid radioactivity greater than 2 times the ODCM limits for 60 minutes or longer

EAL:

RU1.1 Unusual Event

Reading on **any** Table R-1 effluent radiation monitor greater than column "UE" for greater than or equal to 60 min.
(Notes 1, 2, 3)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Note 3: If the effluent flow past an effluent monitor is known to have stopped, indicating that the release path is isolated, the effluent monitor reading is no longer VALID for classification purposes.

Table R-1 Effluent Monitor Classification Thresholds

	Release Point	Monitor	GE	SAE	Alert	UE
	Plant Vent **(WRGM)** PVF684 + PVF685	X-RE-5570 A + B	3.0E+7 μCi/sec	3.0E+6 μCi/sec	3.0E+5 μCi/sec	4.0E+4 μCi/sec
	Main Steam MSLu78 MSLu79 MSLu80 MSLu81	u-RE-2325 u-RE-2326 u-RE-2327 u-RE-2328	97 μCi/ml*	9.7 μCi/ml*	0.97 μCi/ml*	2 x high alarm setpoint*
Liquid	**Liquid Waste** LWE-076	X-RE-5253	-----	-----	-----	2 x high alarm setpoint
Liquid	**Service Water** SSWu65 SSWu66	u-RE-4269 u-RE-4270	-----	-----	-----	2 x high alarm setpoint

* with reactor shutdown

Mode Applicability:

All

Definition(s):

None

Basis:

The column “UE” gaseous and liquid release values in Table R-1 represent two times the alarm setpoint of the specified monitors. The setpoints are established to ensure the ODCM release limits are not exceeded. (ref. 1)

Plant Vent Monitors sample both plant vent stacks prior to discharge to the environment. They detect normal operational levels of noble gases. The noble gas detectors (X-RE-5567A, B) can be used as backups to the wide range gas monitors (X-RE-5570A, B). These monitors communicate with the RM-23s in the Control Room. Indication and annunciation are provided in the Control Room for alert and high radiation levels and monitor failure. (ref. 2)

The WRGM system is a gaseous effluent monitoring system composed of two identical monitors used for detection of noble gas releases through the two plant vent stacks. Exhaust from the main turbine gland steam condenser exhauster is routed to the vent stacks for monitoring prior to release. Particulate and iodine grab samples may also be obtained from the WRGM. These monitors also initiate the automatic closure of the gas release valve in the waste gas processing system on detection of high radiation. Indication and annunciation are provided in the Control Room for alert and high radiation levels and monitor failure. (ref. 2)

There are four online Main Steam Line Monitors (MSL) for each steam generator. Each one consists of a shielded, Category II seismic detector mounted adjacent to a main steam line, a remote RM-80 microprocessor and a remote customer interface junction box. The RM-80 associated with the MSL monitor communicates with the PC-11 CRT console computer. (ref. 2).

Plant Liquid Waste Processing System (LWPS) discharge is continuously monitored by a shielded gamma sensitive (NaI(T1)) scintillation detector. When a LWPS discharge is required, normally locked-closed control valves can be opened directing flow through a path containing a radiation monitor (X-RE-5253) and a control valve which discharges waste to the circulating water discharge tunnel. The control valves are administratively controlled with a key-operated switch selectable to closed, automatic, or “key-held” open modes. In the automatic position, the valve will close on monitor high radiation alarm or monitor failure signals. Indication and annunciation are provided on the Waste Processing System (WPS) control panel for alert or monitor failure alarm and in the Control Room for alert, high, and monitor failure alarms. (ref. 2)

Service Water monitors are provided to monitor the Service Water System for radiation since leakage from radioactive fluid systems could cause potential radioactive leakage to the environment. A shielded gamma sensitive scintillation (NaI(T1)) detector is located in an off-line sample assembly downstream of each component cooling water heat exchanger to monitor service water being discharged. Indication and annunciation are provided at the Control Room RMS console. (ref. 2)

This IC addresses a potential decrease in the level of safety of the plant as indicated by a low-level radiological release that exceeds regulatory commitments for an extended period of time (e.g., an uncontrolled release). It includes any gaseous or liquid radiological release, monitored or un-monitored, including those for which a radioactivity discharge permit is normally prepared.

Nuclear power plants incorporate design features intended to control the release of radioactive effluents to the environment. Further, there are administrative controls established to prevent unintentional releases, and to control and monitor intentional releases. The occurrence of an extended, uncontrolled radioactive release to the environment is indicative of degradation in these features and/or controls.

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

Classification based on effluent monitor readings assumes that a release path to the environment is established. If the effluent flow past an effluent monitor is known to have stopped due to actions to isolate the release path, then the effluent monitor reading is no longer valid for classification purposes.

Releases should not be prorated or averaged. For example, a release exceeding 4 times release limits for 30 minutes does not meet the EAL.

This EAL addresses normally occurring continuous radioactivity releases from monitored gaseous or liquid effluent pathways.

Escalation of the emergency classification level would be via IC RA1.

CPNPP Basis Reference(s):

1. CPNPP ODCM Unit 1 and 2
2. DBD-EE-023 Radiation Monitoring System
3. EAL Section R Revision 6 Table R-1 Effluent Monitor Classification Thresholds Review
4. NEI 99-01 AU1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous or liquid radioactivity greater than 2 times the ODCM limits for 60 minutes or longer.

EAL:

RU1.2	**Unusual Event**
Sample analysis for a gaseous or liquid release indicates a concentration or release rate > 2 x ODCM limits for greater than or equal to 60 min. (Notes 1, 2)	

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Mode Applicability:

All

Definition(s):

None

Basis:

This IC addresses a potential decrease in the level of safety of the plant as indicated by a low-level radiological release that exceeds regulatory commitments for an extended period of time (e.g., an uncontrolled release). It includes any gaseous or liquid radiological release, monitored or un-monitored, including those for which a radioactivity discharge permit is normally prepared.

Nuclear power plants incorporate design features intended to control the release of radioactive effluents to the environment. Further, there are administrative controls established to prevent unintentional releases, and to control and monitor intentional releases. The occurrence of an extended, uncontrolled radioactive release to the environment is indicative of degradation in these features and/or controls.

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

Releases should not be prorated or averaged. For example, a release exceeding 4 times release limits for 30 minutes does not meet the EAL.

This EAL addresses uncontrolled gaseous or liquid releases that are detected by sample analyses or environmental surveys, particularly on unmonitored pathways (e.g., spills of radioactive liquids into storm drains, heat exchanger leakage in river water systems, etc.).

Escalation of the emergency classification level would be via IC RA1.

CPNPP Basis Reference(s):

1. CPNPP ODCM Unit 1 and 2
2. NEI 99-01 AU1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous or liquid radioactivity resulting in offsite dose greater than 10 mrem TEDE or 50 mrem thyroid CDE

EAL:

RA1.1 Alert

Reading on **any** Table R-1 effluent radiation monitor greater than column "ALERT" for greater than or equal to 15 min. (Notes 1, 2, 3, 4)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Note 3: If the effluent flow past an effluent monitor is known to have stopped, indicating that the release path is isolated, the effluent monitor reading is no longer VALID for classification purposes.

Note 4 The pre-calculated effluent monitor values presented in EALs RA1.1, RS1.1 and RG1.1 should be used for emergency classification assessments until the results from a dose assessment using actual meteorology are available.

Table R-1 Effluent Monitor Classification Thresholds

Release Point		Monitor	GE	SAE	Alert	UE
	Plant Vent (WRGM) PVF684 + PVF685	X-RE-5570 A + B	3.0E+7 μCi/sec	3.0E+6 μCi/sec	3.0E+5 μCi/sec	4.0E+4 μCi/sec
	Main Steam MSLu78 MSLu79 MSLu80 MSLu81	u-RE-2325 u-RE-2326 u-RE-2327 u-RE-2328	97 μCi/ml*	9.7 μCi/ml*	0.97 μCi/ml*	2 x high alarm setpoint*
Liquid	**Liquid Waste** LWE-076	X-RE-5253	-----	-----	-----	2 x high alarm setpoint
Liquid	**Service Water** SSWu65 SSWu66	u-RE-4269 u-RE-4270	-----	-----	-----	2 x high alarm setpoint

* with reactor shutdown

Mode Applicability:

All

Definition(s):

None

Basis:

This EAL address gaseous radioactivity releases, that for whatever reason, cause effluent radiation monitor readings corresponding to site boundary doses that exceed either:

- 10 mRem TEDE
- 50 mRem CDE Thyroid

The column “ALERT” gaseous effluent release values in Table R-1 correspond to calculated doses of 1% (10% of the SAE thresholds) of the EPA Protective Action Guidelines (TEDE or CDE Thyroid) (ref. 1).

This IC addresses a release of gaseous or liquid radioactivity that results in projected or actual offsite doses greater than or equal to 1% of the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude represent an actual or potential substantial degradation of the level of safety of the plant as indicated by a radiological release that significantly exceeds regulatory limits (e.g., a significant uncontrolled release).

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at 1% of the EPA PAG of 1,000 mrem while the 50 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Classification based on effluent monitor readings assumes that a release path to the environment is established. If the effluent flow past an effluent monitor is known to have stopped due to actions to isolate the release path, then the effluent monitor reading is no longer valid for classification purposes.

Escalation of the emergency classification level would be via IC RS1.

CPNPP Basis Reference(s):

1. EAL Section R Revision 6 Table R-1 Effluent Monitor Classification Thresholds Review
2. NEI 99-01 AA1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous or liquid radioactivity resulting in offsite dose greater than 10 mrem TEDE or 50 mrem thyroid CDE

EAL:

RA1.2	**Alert**
Dose assessment using actual meteorology indicates doses greater than 10 mrem TEDE or 50 mrem thyroid CDE at or beyond the EXCLUSION AREA BOUNDARY (Note 4)	

Note 4: The pre-calculated effluent monitor values presented in EALs RA1.1, RS1.1 and RG1.1 should be used for emergency classification assessments until the results from a dose assessment using actual meteorology are available.

Mode Applicability:

All

Definition(s):

EXCLUSION AREA BOUNDARY - Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20. See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area and CCNPP ODCM Section 5.0 Design Features.

Basis:

Dose assessments are performed by computer-based method (ref. 1)

This IC addresses a release of gaseous or liquid radioactivity that results in projected or actual offsite doses greater than or equal to 1% of the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude represent an actual or potential substantial degradation of the level of safety of the plant as indicated by a radiological release that significantly exceeds regulatory limits (e.g., a significant uncontrolled release).

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at 1% of the EPA PAG of 1,000 mrem while the 50 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Escalation of the emergency classification level would be via IC RS1.

CPNPP Basis Reference(s):

1. EPP-303 Operation of Computer Based Dose Assessment System
2. NEI 99-01 AA1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous or liquid radioactivity resulting in offsite dose greater than 10 mrem TEDE or 50 mrem thyroid CDE

EAL:

RA1.3 Alert Analysis of a liquid effluent sample indicates a concentration or release rate that would result in doses greater than 10 mrem TEDE or 50 mrem thyroid CDE at or beyond the EXCLUSION AREA BOUNDARY for 60 min. of exposure (Notes 1, 2)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Mode Applicability:

All

Definition(s):

EXCLUSION AREA BOUNDARY - Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20. See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area and CCNPP ODCM Section 5.0 Design Features.

Basis:

Dose assessments based on liquid releases are performed per Offsite Dose Calculation Manual (ref. 1).

This EAL addresses a release of liquid radioactivity that results in projected or actual offsite doses greater than or equal to 1% of the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude represent an actual or potential substantial degradation of the level of safety of the plant as indicated by a radiological release that significantly exceeds regulatory limits (e.g., a significant uncontrolled release).

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at 1% of the EPA PAG of 1,000 mrem while the 50 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Escalation of the emergency classification level would be via IC RS1.

CPNPP Basis Reference(s):

1. CPNPP Offsite Dose Calculation Manual
2. NEI 99-01 AA1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous or liquid radioactivity resulting in offsite dose greater than 10 mrem TEDE or 50 mrem thyroid CDE

EAL:

RA1.4 Alert

Field survey results indicate **EITHER** of the following at or beyond the EXCLUSION AREA BOUNDARY:

- Closed window dose rates greater than 10 mR/hr expected to continue for greater than or equal to 60 min.
- Analyses of field survey samples indicate thyroid CDE greater than 50 mrem for 60 min. of inhalation.

(Notes 1, 2)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Mode Applicability:

All

Definition(s):

EXCLUSION AREA BOUNDARY - Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20. See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area and CCNPP ODCM Section 5.0 Design Features.

Basis:

EPP-309 Onsite/In-Plant Radiological Surveys and Offsite Radiological Monitoring provides guidance for emergency or post-accident radiological environmental monitoring (ref. 1).

This IC addresses a release of gaseous or liquid radioactivity that results in projected or actual offsite doses greater than or equal to 1% of the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude represent an actual or potential substantial degradation of the level of safety of the plant as indicated by a radiological release that significantly exceeds regulatory limits (e.g., a significant uncontrolled release).

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at 1% of the EPA PAG of 1,000 mrem while the 50 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Escalation of the emergency classification level would be via IC RS1.

CPNPP Basis Reference(s):

1. EPP-309 Onsite/In-Plant Radiological Surveys and Offsite Radiological Monitoring
2. NEI 99-01 AA1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous radioactivity resulting in offsite dose greater than 100 mrem TEDE or 500 mrem thyroid CDE

EAL:

RS1.1 Site Area Emergency

Reading on **any** Table R-1 effluent radiation monitor greater than column "SAE" for greater than or equal to 15 min.
(Notes 1, 2, 3, 4)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Note 3: If the effluent flow past an effluent monitor is known to have stopped, indicating that the release path is isolated, the effluent monitor reading is no longer VALID for classification purposes.

Note 4: The pre-calculated effluent monitor values presented in EALs RA1.1, RS1.1 and RG1.1 should be used for emergency classification assessments until the results from a dose assessment using actual meteorology are available.

Table R-1 Effluent Monitor Classification Thresholds

Release Point		Monitor	GE	SAE	Alert	UE
	Plant Vent **(WRGM)** PVF684 + PVF685	X-RE-5570 A + B	3.0E+7 μCi/sec	3.0E+6 μCi/sec	3.0E+5 μCi/sec	4.0E+4 μCi/sec
	Main Steam MSLu78 MSLu79 MSLu80 MSLu81	u-RE-2325 u-RE-2326 u-RE-2327 u-RE-2328	97 μCi/ml*	9.7 μCi/ml*	0.97 μCi/ml*	2 x high alarm setpoint*
Liquid	**Liquid Waste** LWE-076	X-RE-5253	-----	-----	-----	2 x high alarm setpoint
Liquid	**Service Water** SSWu65 SSWu66	u-RE-4269 u-RE-4270	-----	-----	-----	2 x high alarm setpoint

* with reactor shutdown

Mode Applicability:

All

Definition(s):

None

Basis:

This EAL address gaseous radioactivity releases, that for whatever reason, cause effluent radiation monitor readings corresponding to site boundary doses that exceed either:

- 100 mRem TEDE
- 500 mRem CDE Thyroid

The column “SAE” gaseous effluent release value in Table R-1 corresponds to calculated doses of 10% of the EPA Protective Action Guidelines (TEDE or CDE Thyroid) (ref. 1).

This IC addresses a release of gaseous radioactivity that results in projected or actual offsite doses greater than or equal to 10% of the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude are associated with the failure of plant systems needed for the protection of the public.

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at 10% of the EPA PAG of 1,000 mrem while the 500 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Classification based on effluent monitor readings assumes that a release path to the environment is established. If the effluent flow past an effluent monitor is known to have stopped due to actions to isolate the release path, then the effluent monitor reading is no longer valid for classification purposes.

Escalation of the emergency classification level would be via IC RG1.

CPNPP Basis Reference(s):

1. EAL Section R Revision 6 Table R-1 Effluent Monitor Classification Thresholds Review
2. NEI 99-01 AS1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous radioactivity resulting in offsite dose greater than 100 mrem TEDE or 500 mrem thyroid CDE

EAL:

RS1.2	**Site Area Emergency**

Dose assessment using actual meteorology indicates doses greater than 100 mrem TEDE
or
500 mrem thyroid CDE at or beyond the EXCLUSION AREA BOUNDARY (Note 4)

Note 4: The pre-calculated effluent monitor values presented in EALs RA1.1, RS1.1 and RG1.1 should be used for emergency classification assessments until the results from a dose assessment using actual meteorology are available.

Mode Applicability:

All

Definition(s):

EXCLUSION AREA BOUNDARY - Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20. See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area and CCNPP ODCM Section 5.0 Design Features.

Basis:

Dose assessments are performed by computer-based method (ref. 1)

This IC addresses a release of gaseous radioactivity that results in projected or actual offsite doses greater than or equal to 10% of the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude are associated with the failure of plant systems needed for the protection of the public.

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at 10% of the EPA PAG of 1,000 mrem while the 500 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Classification based on effluent monitor readings assumes that a release path to the environment is established. If the effluent flow past an effluent monitor is known to have stopped due to actions to isolate the release path, then the effluent monitor reading is no longer valid for classification purposes.

Escalation of the emergency classification level would be via IC RG1.

CPNPP Basis Reference(s):

1. EPP-303 Operation of Computer Based Dose Assessment System
2. NEI 99-01 AS1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous radioactivity resulting in offsite dose greater than 100 mrem TEDE or 500 mrem thyroid CDE

EAL:

RS1.3 Site Area Emergency

Field survey results indicate **EITHER** of the following at or beyond the EXCLUSION AREA BOUNDARY:

- Closed window dose rates greater than 100 mR/hr expected to continue for greater than or equal to 60 min.
- Analyses of field survey samples indicate thyroid CDE greater than 500 mrem for 60 min. of inhalation.

(Notes 1, 2)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Mode Applicability:

All

Definition(s):

EXCLUSION AREA BOUNDARY - Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20. See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area and CCNPP ODCM Section 5.0 Design Features.

Basis:

EPP-309 Onsite/In-Plant Radiological Surveys and Offsite Radiological Monitoring provides guidance for emergency or post-accident radiological environmental monitoring (ref. 1).

This IC addresses a release of gaseous radioactivity that results in projected or actual offsite doses greater than or equal to 10% of the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude are associated with the failure of plant systems needed for the protection of the public.

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at 10% of the EPA PAG of 1,000 mrem while the 500 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Escalation of the emergency classification level would be via IC RG1.

CPNPP Basis Reference(s):

1. EPP-309 Onsite/In-Plant Radiological Surveys and Offsite Radiological Monitoring
2. NEI 99-01 AS1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous radioactivity resulting in offsite dose greater than 1,000 mrem TEDE or 5,000 mrem thyroid CDE

EAL:

RG1.1 General Emergency

Reading on **any** Table R-1 effluent radiation monitor greater than column "GE" for greater than or equal to 15 min.
(Notes 1, 2, 3, 4)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Note 3: If the effluent flow past an effluent monitor is known to have stopped, indicating that the release path is isolated, the effluent monitor reading is no longer VALID for classification purposes.

Note 4: The pre-calculated effluent monitor values presented in EALs RA1.1, RS1.1 and RG1.1 should be used for emergency classification assessments until the results from a dose assessment using actual meteorology are available.

Table R-1 Effluent Monitor Classification Thresholds

Release Point		Monitor	GE	SAE	Alert	UE
	Plant Vent **(WRGM)** PVF684 + PVF685	X-RE-5570 A + B	3.0E+7 μCi/sec	3.0E+6 μCi/sec	3.0E+5 μCi/sec	4.0E+4 μCi/sec
	Main Steam MSLu78 MSLu79 MSLu80 MSLu81	u-RE-2325 u-RE-2326 u-RE-2327 u-RE-2328	97 μCi/ml*	9.7 μCi/ml*	0.97 μCi/ml*	2 x high alarm setpoint*
Liquid	**Liquid Waste** LWE-076	X-RE-5253	-----	-----	-----	2 x high alarm setpoint
Liquid	**Service Water** SSWu65 SSWu66	u-RE-4269 u-RE-4270	-----	-----	-----	2 x high alarm setpoint

* with reactor shutdown

Mode Applicability:

All

Definition(s):

None

Basis:

This EAL address gaseous radioactivity releases, that for whatever reason, cause effluent radiation monitor readings corresponding to site boundary doses that exceed either:

- 1000 mRem TEDE
- 5000 mRem CDE Thyroid

The column “GE” gaseous effluent release values in Table R-1 correspond to calculated doses of 100% of the EPA Protective Action Guidelines (TEDE or CDE Thyroid) (ref. 1).

This IC addresses a release of gaseous radioactivity that results in projected or actual offsite doses greater than or equal to the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude will require implementation of protective actions for the public.

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at the EPA PAG of 1,000 mrem while the 5,000 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Classification based on effluent monitor readings assumes that a release path to the environment is established. If the effluent flow past an effluent monitor is known to have stopped due to actions to isolate the release path, then the effluent monitor reading is no longer valid for classification purposes.

CPNPP Basis Reference(s):

1. EAL Section R Revision 6 Table R-1 Effluent Monitor Classification Thresholds Review
2. NEI 99-01 AG1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous radioactivity resulting in offsite dose greater than 1,000 mrem TEDE or 5,000 mrem thyroid CDE

EAL:

RG1.2	**General Emergency**
Dose assessment using actual meteorology indicates doses greater than 1,000 mrem TEDE or 5,000 mrem thyroid CDE at or beyond the EXCLUSION AREA BOUNDARY (Note 4)	

Note 4: The pre-calculated effluent monitor values presented in EALs RA1.1, RS1.1 and RG1.1 should be used for emergency classification assessments until the results from a dose assessment using actual meteorology are available.

Mode Applicability:

All

Definition(s):

EXCLUSION AREA BOUNDARY - Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20. See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area and CCNPP ODCM Section 5.0 Design Features.

Basis:

Dose assessments are performed by computer-based method (ref. 1)

This IC addresses a release of gaseous radioactivity that results in projected or actual offsite doses greater than or equal to the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude will require implementation of protective actions for the public.

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at the EPA PAG of 1,000 mrem while the 5,000 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

Classification based on effluent monitor readings assumes that a release path to the environment is established. If the effluent flow past an effluent monitor is known to have stopped due to actions to isolate the release path, then the effluent monitor reading is no longer valid for classification purposes.

CPNPP Basis Reference(s):

1. EPP-303 Operation of Computer Based Dose Assessment System
2. NEI 99-01 AG1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 1 – Radiological Effluent

Initiating Condition: Release of gaseous radioactivity resulting in offsite dose greater than 1,000 mrem TEDE or 5,000 mrem thyroid CDE

EAL:

RG1.3 General Emergency

Field survey results indicate **EITHER** of the following at or beyond the EXCLUSION AREA BOUNDARY:

- Closed window dose rates greater than 1,000 mR/hr expected to continue for greater than or equal to 60 min.
- Analyses of field survey samples indicate thyroid CDE greater than 5,000 mrem for 60 min. of inhalation.

(Notes 1, 2)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit.

Mode Applicability:

All

Definition(s):

EXCLUSION AREA BOUNDARY - Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20. See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area and CCNPP ODCM Section 5.0 Design Features.

Basis:

EPP-309 Onsite/In-Plant Radiological Surveys and Offsite Radiological Monitoring provides guidance for emergency or post-accident radiological environmental monitoring (ref. 1).

This IC addresses a release of gaseous radioactivity that results in projected or actual offsite doses greater than or equal to the EPA Protective Action Guides (PAGs). It includes both monitored and un-monitored releases. Releases of this magnitude will require implementation of protective actions for the public.

Radiological effluent EALs are also included to provide a basis for classifying events and conditions that cannot be readily or appropriately classified on the basis of plant conditions alone. The inclusion of both plant condition and radiological effluent EALs more fully addresses the spectrum of possible accident events and conditions.

The TEDE dose is set at the EPA PAG of 1,000 mrem while the 5,000 mrem thyroid CDE was established in consideration of the 1:5 ratio of the EPA PAG for TEDE and thyroid CDE.

CPNPP Basis Reference(s):

1. EPP-309 Onsite/In-Plant Radiological Surveys and Offsite Radiological Monitoring
2. NEI 99-01 AG1

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 2 – Irradiated Fuel Event

Initiating Condition: Unplanned loss of water level above irradiated fuel

EAL:

RU2.1 Unusual Event

UNPLANNED water level drop in the REFUELING PATHWAY as indicated by **any** low water level alarm or indication, Table R-4

AND

UNPLANNED rise in corresponding area radiation levels as indicated by **any** Table R-2 area radiation monitors

Table R-2 SFP & Refueling Cavity Area Radiation Monitors
SFP: • SFP001, LRAM SFP 2 E WALL (X-RE-6272) • SFP002, LRAM SFP 2 N WALL (X-RE-6273) • SFP003, LRAM SFP 1 E WALL (X-RE-6274) • SFP004, LRAM SFP 1 S WALL (X-RE-6275) **Refueling Cavity:** • RFCu10, LRAM W REFUEL CAV860 (u-RE-6251) • RFCu12, LRAM E REFUEL CAV 860 (u-RE-6253)

Table R-4 Refueling Pathway Low Level Alarms & Indications
Alarms: • RFL CAVITY 1(2) LEVEL LO (upender area) • SFP 1(2) LEVEL LO • RFL CAVITY 1(2) LEVEL LO • SFP 1(2) TRANSFER CANAL LEVEL LO **Indications:** • Plant Computer • Visual Observation

Mode Applicability:

All

Definition(s):

UNPLANNED-. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

REFUELING PATHWAY-. The reactor refueling cavity, spent fuel pool and fuel transfer canal comprise the refueling pathway.

Basis:

Indication of decreasing level includes Spent Fuel Pool Panel (FB 810) (ref. 2):

- RFL CAVITY 1 LEVEL LO (upender area) (SFP-3.3)
- RFL CAVITY 2 LEVEL LO (upender area) (SFP-3.7)
- SFP 1 LEVEL LO (SFP-3.9)
- SFP 2 LEVEL LO (SFP-3.10)
- RFL CAVITY 1 LEVEL LO (vessel area) (SFP-4.3)
- RFL CAVITY 2 LEVEL LO (vessel area) (SFP-4.7)
- SFP 1 TRANSFER CANAL LEVEL LO (SFP-4.9)
- SFP 2 TRANSFER CANAL LEVEL LO (SFP-4.10)

Allowing level to decrease could result in spent fuel being uncovered, reducing spent fuel decay heat removal and creating an extremely hazardous radiation environment. Technical Specification Section 3.7.15 (ref. 4) requires at least 23 ft of water above the Spent Fuel Pool storage racks (857' 3½") (ref. 2). Technical Specification Section 3.9.7 (ref. 5) requires at least 23 ft of water above the Reactor Vessel flange in the refueling cavity (856' 11" in refueling cavity or 407" above core plate) (ref. 6). During refueling, this maintains sufficient water level in the fuel transfer canal, refueling cavity, and SFP to retain iodine fission product activity in the water in the event of a fuel handling accident. ABN-909, Spent Fuel Pool/Refueling Cavity Malfunctions, provides appropriate guidance to restore and maintain normal water levels in the fuel transfer canal, refueling cavity, and SFP, and to determine if water levels have dropped below the Technical Specification LCOs (ref. 2). The fuel transfer canal is only of concern in assessing this EAL when irradiated fuel transfer is in progress, in which case the spent fuel pool gates are open and connected to the fuel transfer canal.

This IC addresses a decrease in water level above irradiated fuel sufficient to cause elevated radiation levels. This condition could be a precursor to a more serious event and is also indicative of a minor loss in the ability to control radiation levels within the plant. It is therefore a potential degradation in the level of safety of the plant.

A water level decrease will be primarily determined by indications from available level instrumentation. Other sources of level indications may include reports from plant personnel (e.g., from a refueling crew) or video camera observations (if available). A significant drop in the water level may also cause an increase in the radiation levels of adjacent areas that can be detected by monitors in those locations.

The effects of planned evolutions should be considered. For example, a refueling bridge area radiation monitor reading may increase due to planned evolutions such as lifting of the reactor vessel head or movement of a fuel assembly. Note that this EAL is applicable only in cases where the elevated reading is due to an unplanned loss of water level.

A drop in water level above irradiated fuel within the reactor vessel may be classified in accordance Recognition Category C during the Cold Shutdown and Refueling modes.

Escalation of the emergency classification level would be via IC RA2.

CPNPP Basis Reference(s):

1. ABN-908 Fuel Handling Accident
2. ABN-909 Spent Fuel Pool/Refueling Cavity Malfunctions
3. 1-ALB-6B SFPCS TRBL
4. Technical Specifications 3.7.15 Fuel Storage Area Water Level
5. Technical Specifications 3.9.7 Refueling Cavity Water Level
6. RFO-102A/B Refueling Operations
7. NEI 99-01 AU2

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 2 – Irradiated Fuel Event

Initiating Condition: Significant lowering of water level above, or damage to, irradiated fuel

EAL:

RA2.1	**Alert**
Uncovery of irradiated fuel in the REFUELING PATHWAY	

Mode Applicability:

All

Definition(s):

REFUELING PATHWAY-. The reactor refueling cavity, spent fuel pool and fuel transfer canal comprise the refueling pathway.

Basis:

This IC addresses events that have caused imminent or actual damage to an irradiated fuel assembly, or a significant lowering of water level within the spent fuel pool. These events present radiological safety challenges to plant personnel and are precursors to a release of radioactivity to the environment. As such, they represent an actual or potential substantial degradation of the level of safety of the plant.

This EAL escalates from RU2.1 in that the loss of level, in the affected portion of the REFUELING PATHWAY, is of sufficient magnitude to have resulted in uncovery of irradiated fuel. Indications of irradiated fuel uncovery may include direct or indirect visual observation (e.g., reports from personnel or camera images), as well as significant changes in water and radiation levels, or other plant parameters. Computational aids may also be used (e.g., a boil-off curve). Classification of an event using this EAL should be based on the totality of available indications, reports and observations.

While an area radiation monitor could detect an increase in a dose rate due to a lowering of water level in some portion of the REFUELING PATHWAY, the reading may not be a reliable indication of whether or not the fuel is actually uncovered. To the degree possible, readings should be considered in combination with other available indications of inventory loss.

A drop in water level above irradiated fuel within the reactor vessel may be classified in accordance Recognition Category C during the Cold Shutdown and Refueling modes.

Escalation of the emergency classification level would be via IC RS1.

CPNPP Basis Reference(s):

1. ABN-909 Spent Fuel Pool/Refueling Cavity Malfunctions
2. NEI 99-01 AA2

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 2 – Irradiated Fuel Event

Initiating Condition: Significant lowering of water level above, or damage to, irradiated fuel

EAL:

RA2.2 Alert

Damage to irradiated fuel resulting in a release of radioactivity

AND

High alarm on **any** of the following:

- **Any** Table R-2 area radiation monitors
- CAGu97, CNTMT AIR PIG GAS (u-RE-5503)
- CAPu98, CNTMT AIR PIG PART (u-RE-5502)
- CAIu99, CNTMT AIR PIG IODINE (u-RE-5566)
- FBV088, FB VENT EXH (X-RE-5700)

Table R-2 SFP & Refueling Cavity Area Radiation Monitors
SFP: • SFP001, LRAM SFP 2 E WALL (X-RE-6272) • SFP002, LRAM SFP 2 N WALL (X-RE-6273) • SFP003, LRAM SFP 1 E WALL (X-RE-6274) • SFP004, LRAM SFP 1 S WALL (X-RE-6275) **Refueling Cavity:** • RFCu10, LRAM W REFUEL CAV860 (u-RE-6251) • RFCu12, LRAM E REFUEL CAV 860 (u-RE-6253)

Mode Applicability:

All

Definition(s):

None

Basis:

The specified radiation monitors are those expected to see increase area radiation levels as a result of damage to irradiated fuel (ref. 1, 2).

The bases for the SFP ventilation radiation High alarm and the SFP and containment area radiation readings are a spent fuel handling accident (ref. 1). In the Fuel Handling Building, a fuel assembly could be dropped in the fuel transfer canal or in the SFP. Should a fuel assembly be dropped in the fuel transfer canal or in the SFP and release radioactivity above a prescribed level, the Fuel Handling Building ventilation monitors sound an alarm, alerting personnel to the problem.

This IC addresses events that have caused imminent or actual damage to an irradiated fuel assembly, or a significant lowering of water level within the spent fuel pool. These events present radiological safety challenges to plant personnel and are precursors to a release of radioactivity to the environment. As such, they represent an actual or potential substantial degradation of the level of safety of the plant.

Escalation of the emergency would be based on either Recognition Category R or C ICs.

This EAL addresses a release of radioactive material caused by mechanical damage to irradiated fuel. Damaging events may include the dropping, bumping or binding of an assembly, or dropping a heavy load onto an assembly. A rise in readings on radiation monitors should be considered in conjunction with in-plant reports or observations of a potential fuel damaging event (e.g., a fuel handling accident).

Escalation of the emergency classification level would be via IC RS1.

CPNPP Basis Reference(s):

1. ABN-908 Fuel Handling Accident
2. ABN-909 Spent Fuel Pool/Refueling Cavity Malfunctions
3. NEI 99-01 AA2

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 2 – Irradiated Fuel Event

Initiating Condition: Significant lowering of water level above, or damage to, irradiated fuel

EAL:

RA2.3	**Alert**
Lowering of spent fuel pool level to El. 844.3' (Level 2)	

Mode Applicability:

All

Definition(s):

None

Basis:

Post-Fukushima order EA-12-051 (ref. 1) required the installation of reliable SFP level indication capable of identifying normal level (Level 1), SFP level 10 ft. above the top of the fuel racks (Level 2) and SFP level at the top of the fuel racks (Level 3) (ref. 1).

Level 2 is the level that is adequate to provide substantial radiation shielding for a person standing on the spent fuel pool operating deck. It represents the range of water level where any necessary operations in the vicinity of the spent fuel pool can be completed without significant dose consequences from direct gamma radiation from the stored spent fuel. Comanche Peak designated as Level 2 the water level 10 feet (± 1.0 foot) above the top of the fuel racks (El 844' – 2.75" rounded to 844.3' indicated) (ref. 2).

The enhanced SFP level instruments (X-LI-4876, 4878, 4877, 4879) do not have indication available in the control room and must be read remotely outside of the control room.

This IC addresses events that have caused imminent or actual damage to an irradiated fuel assembly, or a significant lowering of water level within the spent fuel pool. These events present radiological safety challenges to plant personnel and are precursors to a release of radioactivity to the environment. As such, they represent an actual or potential substantial degradation of the level of safety of the plant.

Escalation of the emergency would be based on either Recognition Category R or C ICs.

Spent fuel pool water level at this value is within the lower end of the level range necessary to prevent significant dose consequences from direct gamma radiation to personnel performing operations in the vicinity of the spent fuel pool. This condition reflects a significant loss of spent fuel pool water inventory and thus it is also a precursor to a loss of the ability to adequately cool the irradiated fuel assembles stored in the pool.

Escalation of the emergency classification level would be via IC RS1.

CPNPP Basis Reference(s):

1. NRC EA-12-51 Issuance of Order to Modify Licenses with Regard to Reliable Spent Fuel Pool Instrumentation
2. TXX-13103 Overall Integrated Plan in Response to March 12,2012 Commission Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation (Order Number EA-12-051), Response to Request for Additional Information

3 NEI 99-01 AA2

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 2 – Irradiated Fuel Event

Initiating Condition: Spent fuel pool level at the top of the fuel racks

EAL:

RS2.1	**Site Area Emergency**
Lowering of spent fuel pool level to El. 835.3’ (Level 3)	

Mode Applicability:

All

Definition(s):

None

Basis:

Post-Fukushima order EA-12-051 (ref. 1) required the installation of reliable SFP level indication capable of identifying normal level (Level 1), SFP level 10 ft. above the top of the fuel racks (Level 2) and SFP level at the top of the fuel racks (Level 3) (ref. 1).

Level 3 is the level where fuel remains covered and actions to implement make-up water addition should no longer be deferred. Level 3 corresponds nominally (i.e., +/- 1 foot) to the highest point of any fuel rack seated in the spent fuel pool. Level 3 is defined in this manner to provide the maximum range of information to operators, decision makers and emergency response personnel. Comanche Peak designated as Level 3 the water level greater than 1 foot above the top of the fuel storage racks plus the accuracy of the SFP level instrument channel (El. 835’ – 2.75” rounded to 835.3’ indicated). Designation of this level as Level 3 is conservative; its selection assures that the fuel will remain covered, and at that point there would be no functional or operational reason to defer action to implement the addition of make-up water to the pool (ref. 2).

The enhanced SFP level instruments (X-LI-4876, 4878, 4877, 4879) do not have indication available in the control room and must be read remotely outside of the control room.

This EAL addresses a significant loss of spent fuel pool inventory control and makeup capability leading to IMMINENT fuel damage. This condition entails major failures of plant functions needed for protection of the public and thus warrant a Site Area Emergency declaration.

It is recognized that this IC would likely not be met until well after another Site Area Emergency IC was met; however, it is included to provide classification diversity.

Escalation of the emergency classification level would be via IC AG1 or RG2.

CPNPP Basis Reference(s):

1. NRC EA-12-51 Issuance of Order to Modify Licenses with Regard to Reliable Spent Fuel Pool Instrumentation
2. TXX-13103 Overall Integrated Plan in Response to March 12,2012 Commission Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation (Order Number EA-12-051), Response to Request for Additional Information
3. NEI 99-01 AS2

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 2 – Irradiated Fuel Event

Initiating Condition: Spent fuel pool level cannot be restored to at least the top of the fuel racks for 60 minutes or longer

EAL:

RG2.1 General Emergency

Spent fuel pool level **cannot** be restored to at least El. 835.3’ (Level 3) for greater than or equal to 60 min. (Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

All

Definition(s):

None

Basis:

Post-Fukushima order EA-12-051 (ref. 1) required the installation of reliable SFP level indication capable of identifying normal level (Level 1), SFP level 10 ft. above the top of the fuel racks (Level 2) and SFP level at the top of the fuel racks (Level 3) (ref. 1).

Level 3 is the level where fuel remains covered and actions to implement make-up water addition should no longer be deferred. Level 3 corresponds nominally (i.e., +/- 1 foot) to the highest point of any fuel rack seated in the spent fuel pool. Level 3 is defined in this manner to provide the maximum range of information to operators, decision makers and emergency response personnel. Comanche Peak designated as Level 3 the water level greater than 1 foot above the top of the fuel storage racks plus the accuracy of the SFP level instrument channel (El. 835’ – 2.75” rounded to 835.3’ indicated). Designation of this level as Level 3 is conservative; its selection assures that the fuel will remain covered, and at that point there would be no functional or operational reason to defer action to implement the addition of make-up water to the pool (ref. 2).

The enhanced SFP level instruments (X-LI-4876, 4878, 4877, 4879) do not have indication available in the control room and must be read remotely outside of the control room.

This EAL addresses a significant loss of spent fuel pool inventory control and makeup capability leading to a prolonged uncovery of spent fuel. This condition will lead to fuel damage and a radiological release to the environment.

It is recognized that this IC would likely not be met until well after another General Emergency IC was met; however, it is included to provide classification diversity.

CPNPP Basis Reference(s):

1. NRC EA-12-51 Issuance of Order to Modify Licenses with Regard to Reliable Spent Fuel Pool Instrumentation
2. TXX-13103 Overall Integrated Plan in Response to March 12,2012 Commission Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation (Order Number EA-12-051), Response to Request for Additional Information
3. NEI 99-01 AG2

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 3 – Area Radiation Levels

Initiating Condition: Radiation levels that IMPEDE access to equipment necessary for normal plant operations, cooldown or shutdown

EAL:

RA3.1 Alert

Dose rates greater than 15 mR/hr in **EITHER** of the following areas:

Control Room

CRM048 (X-RE-6281) or CRM049 (X-RE-6282)

OR

Central Alarm Station (by survey)

Mode Applicability:

All

Definition(s):

None

Basis:

X-RE-6281 and X-RE-6282 are the installed Control Room area radiation monitors and may be used to assess this EAL threshold (range of 1E-4 to 1E+5 mR/hr). However, no permanently installed area radiation monitoring is installed in the CAS and therefore this threshold must be assessed via local radiation survey (ref. 1).

This IC addresses elevated radiation levels in certain plant rooms/areas sufficient to preclude or impede personnel from performing actions necessary to maintain normal plant operation, or to perform a normal plant cooldown and shutdown. As such, it represents an actual or potential substantial degradation of the level of safety of the plant. The Emergency Coordinator should consider the cause of the increased radiation levels and determine if another IC may be applicable.

Escalation of the emergency classification level would be via Recognition Category R, C or F ICs.

CPNPP Basis Reference(s):

1. DBD-EE-023 Radiation Monitoring System
2. NEI 99-01 AA3

Category: R – Abnormal Rad Levels / Rad Effluent

Subcategory: 3 – Area Radiation Levels

Initiating Condition: Radiation levels that IMPEDE access to equipment necessary for normal plant operations, cooldown or shutdown

EAL:

RA3.2 Alert

An UNPLANNED event results in radiation levels that prohibit or IMPEDE access to **any** Table R-3 rooms or areas (Note 5)

Note 5: If the equipment in the listed room or area was already inoperable or out-of-service before the event occurred, then **no** emergency classification is warranted.

Table R-3 Safe Operation & Shutdown Rooms/Areas	
Room/Area	**Mode Applicability**
Charging Pump Rooms	1, 2, 3, 4, 5, 6
CVCS Valve Rooms	1, 2, 3, 4, 5, 6
1E Switchgear Rooms	All
RHR Pump Rooms	4, 5, 6

Mode Applicability:

All

Definition(s):

IMPEDE(D) - Personnel access to a room or area is hindered to an extent that extraordinary measures are necessary to facilitate entry of personnel into the affected room/area (e.g., requiring use of protective equipment, such as SCBAs, that is not routinely employed).

UNPLANNED-. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

For this EAL, area or room access is considered impeded if radiation levels require locked high radiation controls to to be imposed.

If the equipment in the listed room or area was already inoperable, or out-of-service, before the event occurred, then no emergency should be declared since the event will have no adverse impact beyond that already allowed by Technical Specifications at the time of the event.

The list of plant rooms or areas with entry-related mode applicability identified specify those rooms or areas that contain equipment which require a manual/local action as specified in operating procedures used for normal plant operation, cooldown and shutdown. Rooms or areas in which actions of a contingent or emergency nature would be performed (e.g., an action to address an off-normal or emergency condition such as emergency repairs, corrective measures or emergency operations) are not included. In addition, the list specifies the plant mode(s) during which entry would be required for each room or area (ref. 1).

This IC addresses elevated radiation levels in certain plant rooms/areas sufficient to preclude or impede personnel from performing actions necessary to maintain normal plant operation, or to perform a normal plant cooldown and shutdown. As such, it represents an actual or potential substantial degradation of the level of safety of the plant. The Emergency Coordinator should consider the cause of the increased radiation levels and determine if another IC may be applicable.

For RA3.2, an Alert declaration is warranted if entry into the affected room/area is, or may be, procedurally required during the plant operating mode in effect at the time of the elevated radiation levels. The emergency classification is not contingent upon whether entry is actually necessary at the time of the increased radiation levels. Access should be considered as impeded if extraordinary measures are necessary to facilitate entry of personnel into the affected room/area (e.g., installing temporary shielding, requiring use of non-routine protective equipment, requesting an extension in dose limits beyond normal administrative limits).

An emergency declaration is not warranted if any of the following conditions apply:

- The plant is in an operating mode different than the mode specified for the affected room/area (i.e., entry is not required during the operating mode in effect at the time of the elevated radiation levels). For example, the plant is in Mode 1 when the radiation increase occurs, and the procedures used for normal operation, cooldown and shutdown do not require entry into the affected room until Mode 4.
- The increased radiation levels are a result of a planned activity that includes compensatory measures which address the temporary inaccessibility of a room or area (e.g., radiography, spent filter or resin transfer, etc.).
- The action for which room/area entry is required is of an administrative or record keeping nature (e.g., normal rounds or routine inspections).
- The access control measures are of a conservative or precautionary nature, and would not actually prevent or impede a required action.

Escalation of the emergency classification level would be via Recognition Category R, C or F ICs.

CPNPP Basis Reference(s):

1. Attachment 3 Safe Operation & Shutdown Areas Tables R-3 & H-2 Bases
2. NEI 99-01 AA3

Category E – Independent Spent Fuel Storage Installation (ISFSI)

EAL Group: Any (EALs in this category are applicable to any plant condition, hot or cold.)

An independent spent fuel storage installation (ISFSI) is a complex that is designed and constructed for the interim storage of spent nuclear fuel and other radioactive materials associated with spent fuel storage. A significant amount of the radioactive material contained within a canister must escape its packaging and enter the biosphere for there to be a significant environmental effect resulting from an accident involving the dry storage of spent nuclear fuel.

An Unusual Event is declared on the basis of the occurrence of an event of sufficient magnitude that a loaded cask confinement boundary is damaged or violated.

Category: ISFSI

Subcategory: Confinement Boundary

Initiating Condition: Damage to a loaded cask CONFINEMENT BOUNDARY

EAL:

EU1.1 Unusual Event

Damage to a loaded cask CONFINEMENT BOUNDARY as indicated by an on-contact radiation reading greater than **EITHER**:

- 60 mrem/hr (ϒ + η) on the top of the overpack
- 600 mrem/hr (ϒ + η) on the side of the overpack (excluding inlet and outlet ducts)

Mode Applicability:

All

Definition(s):

CONFINEMENT BOUNDARY-. The barrier(s) between spent fuel and the environment once the spent fuel is processed for dry storage. As applied to the CPNPP ISFSI, the CONFINEMENT BOUNDARY is defined to be the Multi-Purpose Canister (MPC).

Basis:

The ISFSI includes the dry-cask storage system, the cask transfer facility, onsite transporter, and the storage pads. The dry-cask storage system is the HI-STORM 100 System. This is a canister-based storage system that stores spent nuclear fuel in a vertical orientation. It consists of three discrete components: the MPC, the HI-TRAC 125 Transfer Cask, and the HI-STORM 100 System Overpack. The MPC provides the confinement boundary for the stored fuel. The HI-TRAC 125 Transfer Cask provides radiation shielding and structural protection of the MPC during transfer operations, while the storage overpack provides radiation shielding and structural protection of the MPC during storage (ref. 1).

The value shown represents 2 times the limits specified in the ISFSI Certificate of Compliance Technical Specification section 5.7.4 for radiation external to a loaded MPC overpack (ref. 1).

This IC addresses an event that results in damage to the CONFINEMENT BOUNDARY of a storage cask containing spent fuel. It applies to irradiated fuel that is licensed for dry storage beginning at the point that the loaded storage cask is sealed. The issues of concern are the creation of a potential or actual release path to the environment, degradation of one or more fuel assemblies due to environmental factors, and configuration changes which could cause challenges in removing the cask or fuel from storage.

The existence of “damage” is determined by radiological survey. The technical specification multiple of “2 times”, which is also used in Recognition Category R IC RU1, is used here to distinguish between non-emergency and emergency conditions. The emphasis for this classification is the degradation in the level of safety of the spent fuel cask and not the magnitude of the associated dose or dose rate. It is recognized that in the case of extreme damage to a loaded cask, the fact that the "on-contact" dose rate limit is exceeded may be determined based on measurement of a dose rate at some distance from the cask.

Security-related events for ISFSIs are covered under ICs HU1 and HA1.

CPNPP Basis Reference(s):

1. HI-2104635, HI-STORM Certificate of Compliance Appendix A Technical Specification Section 5.7.4
2. RPI-792 HI-STORM Overpack Surface Dose Rates
3. NEI 99-01 E-HU1

Category C – Cold Shutdown / Refueling System Malfunction

EAL Group: Cold Conditions (RCS temperature ≤ 200ºF); EALs in this category are applicable only in one or more cold operating modes.

Category C EALs are directly associated with cold shutdown or refueling system safety functions. Given the variability of plant configurations (e.g., systems out-of-service for maintenance, containment open, reduced AC power redundancy, time since shutdown) during these periods, the consequences of any given initiating event can vary greatly. For example, a loss of decay heat removal capability that occurs at the end of an extended outage has less significance than a similar loss occurring during the first week after shutdown. Compounding these events is the likelihood that instrumentation necessary for assessment may also be inoperable. The cold shutdown and refueling system malfunction EALs are based on performance capability to the extent possible with consideration given to RCS integrity, containment closure, and fuel clad integrity for the applicable operating modes (5 - Cold Shutdown, 6 - Refueling, D – Defueled).

The events of this category pertain to the following subcategories:

1. RCS Level

RCS water level is directly related to the status of adequate core cooling and, therefore, fuel clad integrity.

2. Loss of Emergency AC Power

Loss of emergency plant electrical power can compromise plant safety system operability including decay heat removal and emergency core cooling systems which may be necessary to ensure fission product barrier integrity. This category includes loss of onsite and offsite power sources for 6.9 KV AC emergency buses.

3. RCS Temperature

Uncontrolled or inadvertent temperature or pressure increases are indicative of a potential loss of safety functions.

4. Loss of Vital DC Power

Loss of emergency plant electrical power can compromise plant safety system operability including decay heat removal and emergency core cooling systems which may be necessary to ensure fission product barrier integrity. This category includes loss of power to or degraded voltage on the 125V DC vital buses.

5. Loss of Communications

Certain events that degrade plant operator ability to effectively communicate with essential personnel within or external to the plant warrant emergency classification.

6. Hazardous Event Affecting Safety Systems

Certain hazardous natural and technological events may result in visible damage to or degraded performance of safety systems warranting classification.

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: UNPLANNED loss of RCS inventory for 15 minutes or longer

EAL:

CU1.1 **Unusual Event**
UNPLANNED loss of reactor coolant results in RCS water level less than a required lower limit for greater than or equal to 15 min. (Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

5 - Cold Shutdown, 6 - Refueling

Definition(s):

UNPLANNED-. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

With the plant in Cold Shutdown, RCS water level is normally maintained above the pressurizer low level setpoint of 17% (ref. 1). However, if RCS level is being controlled below the pressurizer low level setpoint, or if level is being maintained in a designated band in the reactor vessel it is the inability to maintain level above the low end of the designated control band due to a loss of inventory resulting from a leak in the RCS that is the concern.

With the plant in Refueling mode, RCS water level is normally maintained at or above the reactor vessel flange (Technical Specification LCO 3.9.7 requires at least 23 ft. of water above the top of the reactor vessel flange in the refueling cavity during refueling operations) (ref. 2). The Reactor Vessel flange level is 834’ ½” elevation or 132.5 in. above the upper core plate (top) (ref. 3).

This IC addresses the inability to restore and maintain water level to a required minimum level (or the lower limit of a level band), or a loss of the ability to monitor RCS level concurrent with indications of coolant leakage. Either of these conditions is considered to be a potential degradation of the level of safety of the plant.

Refueling evolutions that decrease RCS water inventory are carefully planned and controlled. An UNPLANNED event that results in water level decreasing below a procedurally required limit warrants the declaration of an Unusual Event due to the reduced water inventory that is available to keep the core covered.

This EAL recognizes that the minimum required RCS level can change several times during the course of a refueling outage as different plant configurations and system lineups are implemented. This EAL is met if the minimum level, specified for the current plant conditions, cannot be maintained for 15 minutes or longer. The minimum level is typically specified in the applicable operating procedure but may be specified in another controlling document.

The 15-minute threshold duration allows sufficient time for prompt operator actions to restore and maintain the expected water level. This criterion excludes transient conditions causing a brief lowering of water level.

Continued loss of RCS inventory may result in escalation to the Alert emergency classification level via either IC CA1 or CA3.

CPNPP Basis Reference(s):

1. ALM-0052A/B Alarm Procedure u-ALB-5B (5B-3.6)
2. Technical Specification Section 3.9.7 Refueling Cavity Water Level
3. IPO-010A/B Reactor Coolant System Reduced Inventory Operations
4. NEI 99-01 CU1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: UNPLANNED loss of RCS inventory for 15 minutes or longer

EAL:

CU1.2 Unusual Event

RCS water level cannot be monitored

AND EITHER

- UNPLANNED increase in **any** Table C-1 sump/tank level due to loss of RCS inventory
- Visual observation of UNISOLABLE RCS leakage

Table C-1 Sumps / Tanks
• Containment Sump 1 • Containment Sump 2 • Reactor Cavity Sump • CCW Surge Tank A • CCW Surge Tank B • PRT • RCDT

Mode Applicability:

5 - Cold Shutdown, 6 – Refueling

Definition(s):

UNISOLABLE - An open or breached system line that cannot be isolated, remotely or locally.

UNPLANNED-. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

In Cold Shutdown mode, the RCS will normally be intact and standard RCS level monitoring means are available.

In this EAL, all water level indication is unavailable and the RCS inventory loss must be detected by indirect leakage indications (Table C-1). Level increases must be evaluated against other potential sources of leakage such as cooling water sources inside the containment to ensure they are indicative of RCS leakage. If the make-up rate to the RCS unexplainably rises above the pre-established rate, a loss of RCS inventory may be occurring even if the source of the leakage cannot be immediately identified. Visual observation of leakage from systems connected to the RCS that cannot be isolated could also be indicative of a loss of RCS inventory (ref. 1, 2, 3, 4).

This IC addresses the inability to restore and maintain water level to a required minimum level (or the lower limit of a level band), or a loss of the ability to monitor RCS level concurrent with indications of coolant leakage. Either of these conditions is considered to be a potential degradation of the level of safety of the plant.

Refueling evolutions that decrease RCS water inventory are carefully planned and controlled. An UNPLANNED event that results in water level decreasing below a procedurally required limit warrants the declaration of an Unusual Event due to the reduced water inventory that is available to keep the core covered.

Continued loss of RCS inventory may result in escalation to the Alert emergency classification level via either IC CA1 or CA3.

CPNPP Basis Reference(s):

1. IPO-010A/B Reactor Coolant System Reduced Inventory Operations
2. SOP-101A/B Reactor Coolant System
3. ABN-103 Excessive Reactor Coolant Leakage
4. ABN-108 Shutdown Loss of Coolant
5. NEI 99-01 CU1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: Loss of RCS inventory

EAL:

CA1.1 Alert

Loss of RCS inventory as indicated by RCS level less than 48 in. above upper core plate (top)

Mode Applicability:

5 - Cold Shutdown, 6 – Refueling

Definition(s):

None

Basis:

When Reactor Vessel water level decreases to 48 in. above the upper core plate (top) (EL 827' 0"), RHR pump cavitation may occur. RCS level can be monitored by one or more of the following (ref. 1, 2, 3, 4, 5, 6):

- RCS Level Wide Range u-LI-3615B
- RCS Level Narrow Range u-LI-3615A
- RCS Extended Wide Range u-LI-3615C
- Mansell Level Monitor System u-LT-3619A/B/C-1, -2
- Plant Computer
- RVLIS
- Ultrasonic Level monitoring (optional)

This IC addresses conditions that are precursors to a loss of the ability to adequately cool irradiated fuel (i.e., a precursor to a challenge to the fuel clad barrier). This condition represents a potential substantial reduction in the level of plant safety.

For this EAL, a lowering of RCS water level below 48 in. above the upper core plate (top) indicates that operator actions have not been successful in restoring and maintaining RCS water level. The heat-up rate of the coolant will increase as the available water inventory is reduced. A continuing decrease in water level will lead to core uncovery.

Although related, this EAL is concerned with the loss of RCS inventory and not the potential concurrent effects on systems needed for decay heat removal (e.g., loss of a Decay Heat Removal suction point). An increase in RCS temperature caused by a loss of decay heat removal capability is evaluated under IC CA3.

If RCS water level continues to lower, then escalation to Site Area Emergency would be via IC CS1.

CPNPP Basis Reference(s):

1. IPO-010A/B Reactor Coolant System Reduced Inventory Operations
2. INC-6269 Calibration of the Mansell RCS Measurement System
3. SOP-101A/B Reactor Coolant System
4. ABN-103 Excessive Reactor Coolant Leakage
5. ABN-104 Residual Heat Removal System Malfunction
6. ABN-108 Shutdown Loss of Coolant
7. NEI 99-01 CA1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: Loss of RCS inventory

EAL:

CA1.2 Alert

RCS water level cannot be monitored for greater than or equal to 15 min. (Note 1)

AND EITHER

- UNPLANNED increase in **any** Table C-1 sump/tank level due to loss of RCS inventory
- Visual observation of UNISOLABLE RCS leakage

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table C-1 Sumps / Tanks
• Containment Sump 1 • Containment Sump 2 • Reactor Cavity Sump • CCW Surge Tank A • CCW Surge Tank B • PRT • RCDT

Mode Applicability:

5 - Cold Shutdown, 6 – Refueling

Definition(s):

UNISOLABLE - An open or breached system line that cannot be isolated, remotely or locally.

UNPLANNED-. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

In Cold Shutdown mode, the RCS will normally be intact and standard RCS level monitoring means are available.

In the Refuel mode, the RCS is not intact and RPV level may be monitored by different means, including the ability to monitor level visually.

In this EAL, all RCS water level indication would be unavailable for greater than 15 minutes, and the RCS inventory loss must be detected by indirect leakage indications (Table C-1).

Surveillance procedures provide instructions for calculating primary system leak rate by manual or computer-based water inventory balances. Level increases must be evaluated against other potential sources of leakage such as cooling water sources inside the containment to ensure they are indicative of RCS leakage. If the make-up rate to the RCS unexplainably rises above the pre-established rate, a loss of RCS inventory may be occurring even if the source of the leakage cannot be immediately identified. Visual observation of leakage from systems connected to the RCS that cannot be isolated could also be indicative of a loss of RCS inventory (ref. 1, 2, 3).

This IC addresses conditions that are precursors to a loss of the ability to adequately cool irradiated fuel (i.e., a precursor to a challenge to the fuel clad barrier). This condition represents a potential substantial reduction in the level of plant safety.

For this EAL, the inability to monitor RCS level may be caused by instrumentation and/or power failures, or water level dropping below the range of available instrumentation. If water level cannot be monitored, operators may determine that an inventory loss is occurring by observing changes in sump and/or tank levels. Sump and/or tank level changes must be evaluated against other potential sources of water flow to ensure they are indicative of leakage from the RCS.

The 15-minute duration for the loss of level indication was chosen because it is half of the EAL duration specified in IC CS1.

If the RCS inventory level continues to lower, then escalation to Site Area Emergency would be via IC CS1.

CPNPP Basis Reference(s):

1. ABN-103 Excessive Reactor Coolant Leakage
2. ABN-108 Shutdown Loss of Coolant
3. FSAR 5.2.5.2
4. NEI 99-01 CA1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: Loss of RCS inventory affecting core decay heat removal capability

EAL:

CS1.1 **Site Area Emergency**
With CONTAINMENT CLOSURE **not** established, RCS level less than 27.3 in. above upper core plate (top)

Mode Applicability:

5 – Cold Shutdown, 6 – Refueling

Definition(s):

CONTAINMENT CLOSURE - The procedurally defined actions taken to secure containment and its associated structures, systems, and components as a functional barrier to fission product release under shutdown conditions. Containment closure means that all potential escape paths are closed or capable of being closed:

A. All penetrations providing direct access from Containment atmosphere to outside atmosphere are closed except:
   - Penetrations with automatic valves capable of being closed by an operable CVI
   - Penetrations under administrative controls (e.g., Control Room notified and designated person to close if required by fuel handling accident)
B. Equipment hatch is closed and held in place by 4 bolts, or is capable of being closed and held in place by 4 bolts
C. One emergency airlock door is closed
D. One personnel airlock door is capable of being closed

Basis:

When Reactor Vessel water level decreases to 27.25 in. (rounded to 27.3 in. for instrument readability), 825'-3 ¼" elevation (ref. 1), water level is six inches below the elevation of the bottom of the RCS hot leg penetration. When Reactor Vessel water level drops significantly below the elevation of the bottom of the RCS hot leg penetration, all sources of RCS injection have failed or are incapable of making up for the inventory loss. RCS level can be monitored by one or more of the following (ref. 1, 2, 3):

- RCS Level Wide Range u-LI-3615B
- RCS Level Narrow Range u-LI-3615A
- RCS Extended Wide Range u-LI-3615C
- Mansell Level Monitor System u-LT-3619A/B/C-1, -2
- Plant Computer
- RVLIS
- Ultrasonic Level monitoring (optional)

In Refueling mode, Reactor Vessel water level indication from RVLIS is likely unavailable but alternate means of level indication are normally installed (including visual observation) to assure that the ability to monitor water level will not be interrupted.

The status of Containment closure is tracked if plant conditions change that could raise the risk of a fission product release as a result of a loss of decay heat removal (ref. 4, 5).

This IC addresses a significant and prolonged loss of reactor vessel/RCS inventory control and makeup capability leading to IMMINENT fuel damage. The lost inventory may be due to a RCS component failure, a loss of configuration control or prolonged boiling of reactor coolant. These conditions entail major failures of plant functions needed for protection of the public and thus warrant a Site Area Emergency declaration.

Following an extended loss of core decay heat removal and inventory makeup, decay heat will cause reactor coolant boiling and a further reduction in reactor vessel level. If RCS level cannot be restored, fuel damage is probable.

Outage/shutdown contingency plans typically provide for re-establishing or verifying CONTAINMENT CLOSURE following a loss of heat removal or RCS inventory control functions. The difference in the specified RCS/reactor vessel levels of EALs CS1.1 and CS1.2 reflect the fact that with CONTAINMENT CLOSURE established, there is a lower probability of a fission product release to the environment.

This EAL addresses concerns raised by Generic Letter 88-17, Loss of Decay Heat Removal; SECY 91-283, Evaluation of Shutdown and Low Power Risk Issues; NUREG-1449, Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States; and NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management.

Escalation of the emergency classification level would be via IC CG1 or RG1

CPNPP Basis Reference(s):

1. IPO-010A/B Reactor Coolant System Reduced Inventory Operations
2. INC-6269 Calibration of the Mansell RCS Measurement System
3. SOP-101A/B Reactor Coolant System
4. Technical Specifications 3.9.4
5. OPT-408A/B Refueling Containment Penetration Verification
6. NEI 99-01 CS1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: Loss of RCS inventory affecting core decay heat removal capability

EAL:

CS1.2	**Site Area Emergency**
With CONTAINMENT CLOSURE established, RCS level less than or equal to 0 in. above upper core plate (top)	

Mode Applicability:

5 – Cold Shutdown, 6 – Refueling

Definition(s):

CONTAINMENT CLOSURE - The procedurally defined actions taken to secure containment and its associated structures, systems, and components as a functional barrier to fission product release under shutdown conditions. Containment closure means that all potential escape paths are closed or capable of being closed:

A. All penetrations providing direct access from Containment atmosphere to outside atmosphere are closed except:
   - Penetrations with automatic valves capable of being closed by an operable CVI
   - Penetrations under administrative controls (e.g., Control Room notified and designated person to close if required by fuel handling accident)
B. Equipment hatch is closed and held in place by 4 bolts, or is capable of being closed and held in place by 4 bolts
C. One emergency airlock door is closed
D. One personnel airlock door is capable of being closed

Basis:

When Reactor Vessel water level drops below 0 in. above upper core plate (top) 823'-0" elevation (ref. 1), core uncovery is about to occur. RCS level can be monitored by one or more of the following (ref. 1, 2, 3):

- RCS Level Wide Range u-LI-3615B
- RCS Level Narrow Range u-LI-3615A
- RCS Extended Wide Range u-LI-3615C
- Mansell Level Monitor System u-LT-3619A/B/C-1, -2
- Plant Computer
- RVLIS
- Ultrasonic Level monitoring (optional)

Under the conditions specified by this EAL, continued lowering of Reactor Vessel water level is indicative of a loss of inventory control. Inventory loss may be due to a vessel breach, RCS pressure boundary leakage or continued boiling in the Reactor Vessel. The magnitude of this loss of water indicates that makeup systems have not been effective and may not be capable of preventing further RCS or Reactor Vessel water level drop and potential core uncovery. The inability to restore and maintain level after reaching this setpoint infers a failure of the RCS barrier and Potential Loss of the Fuel Clad barrier.

The status of Containment closure is tracked if plant conditions change that could raise the risk of a fission product release as a result of a loss of decay heat removal (ref. 4, 5).

This IC addresses a significant and prolonged loss of reactor vessel/RCS inventory control and makeup capability leading to IMMINENT fuel damage. The lost inventory may be due to a RCS component failure, a loss of configuration control or prolonged boiling of reactor coolant. These conditions entail major failures of plant functions needed for protection of the public and thus warrant a Site Area Emergency declaration.

Following an extended loss of core decay heat removal and inventory makeup, decay heat will cause reactor coolant boiling and a further reduction in reactor vessel level. If RCS level cannot be restored, fuel damage is probable.

Outage/shutdown contingency plans typically provide for re-establishing or verifying CONTAINMENT CLOSURE following a loss of heat removal or RCS inventory control functions. The difference in the specified RCS/reactor vessel levels of EALs CS1.1 and CS1.2 reflect the fact that with CONTAINMENT CLOSURE established, there is a lower probability of a fission product release to the environment.

This EAL addresses concerns raised by Generic Letter 88-17, Loss of Decay Heat Removal; SECY 91-283, Evaluation of Shutdown and Low Power Risk Issues; NUREG-1449, Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States; and NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management.

Escalation of the emergency classification level would be via IC CG1 or RG1

CPNPP Basis Reference(s):

1. IPO-010A/B Reactor Coolant System Reduced Inventory Operations
2. INC-6269 Calibration of the Mansell RCS Measurement System
3. SOP-101A/B Reactor Coolant System
4. Technical Specifications 3.9.4
5. OPT-408A/B Refueling Containment Penetration Verification
6. NEI 99-01 CS1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: Loss of RCS inventory affecting core decay heat removal capability

EAL:

CS1.3 Site Area Emergency

RCS water level cannot be monitored for greater than or equal to 30 min. (Note 1)

AND

Core uncovery is indicated by **any** of the following:

- UNPLANNED increase in **any** Table C-1 sump/tank level of sufficient magnitude to indicate core uncovery
- Erratic Source Range Monitor indication
- greater than 20,000 R/hr on **any** of the following:
  - CTEu16, Containment HRRM (u-RE-6290A)
  - CTWu17, Containment HRRM (u-RE-6290B)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table C-1 Sumps / Tanks
• Containment Sump 1 • Containment Sump 2 • Reactor Cavity Sump • CCW Surge Tank A • CCW Surge Tank B • PRT • RCDT

Mode Applicability:

5 – Cold Shutdown, 6 – Refueling

Definition(s):

UNISOLABLE - An open or breached system line that cannot be isolated, remotely or locally.

UNPLANNED-. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

In Cold Shutdown mode, the RCS will normally be intact and standard RCS level monitoring means are available.

In the Refueling mode, the RCS is not intact and RCS level may be monitored by different means, including the ability to monitor level visually.

In this EAL, all RCS water level indication would be unavailable for greater than 30 minutes, and the RCS inventory loss must be detected by indirect leakage indications (Table C-1). Surveillance procedures provide instructions for calculating primary system leak rate by manual or computer-based water inventory balances. Level increases must be evaluated against other potential sources of leakage such as cooling water sources inside the containment to ensure they are indicative of RCS leakage. If the make-up rate to the RCS unexplainably rises above the pre-established rate, a loss of RCS inventory may be occurring even if the source of the leakage cannot be immediately identified (ref. 1, 2).

The RCS inventory loss may be detected by the Containment High Range Radiation Monitor (HRRM) or erratic Source Range Monitor indication. As water level in the Reactor Vessel lowers, the dose rate above the core will rise. The dose rate due to this core shine should result in Containment High Range Radiation Monitor indication greater than 20,000 R/hr (ref. 3). The Containment HRRMs have a range of 1E-1 to 1E+8 R/hr.

Post-TMI accident studies indicated that the installed PWR nuclear instrumentation will operate erratically when the core is uncovered and that this should be used as a tool for making such determinations (ref. 4, 5).

This IC addresses a significant and prolonged loss of RCS inventory control and makeup capability leading to IMMINENT fuel damage. The lost inventory may be due to a RCS component failure, a loss of configuration control or prolonged boiling of reactor coolant. These conditions entail major failures of plant functions needed for protection of the public and thus warrant a Site Area Emergency declaration.

Following an extended loss of core decay heat removal and inventory makeup, decay heat will cause reactor coolant boiling and a further reduction in reactor vessel level. If RCS level cannot be restored, fuel damage is probable.

The 30-minute criterion is tied to a readily recognizable event start time (i.e., the total loss of ability to monitor level), and allows sufficient time to monitor, assess and correlate reactor and plant conditions to determine if core uncovery has actually occurred (i.e., to account for various accident progression and instrumentation uncertainties). It also allows sufficient time for performance of actions to terminate leakage, recover inventory control/makeup equipment and/or restore level monitoring.

This EAL addresses concerns raised by Generic Letter 88-17, Loss of Decay Heat Removal; SECY 91-283, Evaluation of Shutdown and Low Power Risk Issues; NUREG-1449, Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States; and NUMARC 91-06, Guidelines for Industry Actions to Assess Shutdown Management.

Escalation of the emergency classification level would be via IC CG1 or RG1

CPNPP Basis Reference(s):

1. ABN-103 Excessive Reactor Coolant Leakage
2. ABN-108 Shutdown Loss of Coolant
3. Engineering Handbook, Guidelines for Events Beyond Design Basis: Spent Fuel Pools, Figure D “Dose Rate at Elevation 860’ above Stored Fuel vs. Water Level Depth in SFP”
4. Severe Accident Management Guidance Technical Basis Report, Volume 1: Candidate High-Level Actions and Their Effects, pgs 2-18, 2-19
5. Nuclear Safety Analysis Center (NSAC), 1980, “Analysis of Three Mile Island - Unit 2 Accident,” NSAC-1
6. NEI 99-01 CS1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: Loss of RCS inventory affecting fuel clad integrity with containment challenged

EAL:

CG1.1	**General Emergency**

RCS level less than or equal to 0 in. above upper core plate (top) for ≥ 30 min. (Note 1)

AND

Any Containment Challenge indication, Table C-2

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 6: If CONTAINMENT CLOSURE is re-established prior to exceeding the 30-minute time limit, declaration of a General Emergency is not required.

Table C-2 Containment Challenge Indications
• CONTAINMENT CLOSURE **not** established (Note 6) • Containment hydrogen concentration greater than 4% • Unplanned rise greater than 1 psig in Containment pressure

Mode Applicability:

5 – Cold Shutdown, 6 – Refueling

Definition(s):

CONTAINMENT CLOSURE - The procedurally defined actions taken to secure containment and its associated structures, systems, and components as a functional barrier to fission product release under shutdown conditions. Containment closure means that all potential escape paths are closed or capable of being closed:

A. All penetrations providing direct access from Containment atmosphere to outside atmosphere are closed except:
   - Penetrations with automatic valves capable of being closed by an operable CVI
   - Penetrations under administrative controls (e.g., Control Room notified and designated person to close if required by fuel handling accident)
B. Equipment hatch is closed and held in place by 4 bolts, or is capable of being closed and held in place by 4 bolts
C. One emergency airlock door is closed
D. One personnel airlock door is capable of being closed

Basis:

When Reactor Vessel water level drops below 0 in. above upper core plate (top) 823’-0” elevation (ref. 1), core uncovery is about to occur. RCS level can be monitored by one or more of the following (ref. 1, 2, 3):

- RCS Level Wide Range u-LI-3615B
- RCS Level Narrow Range u-LI-3615A
- RCS Extended Wide Range u-LI-3615C
- Mansell Level Monitor System u-LT-3619A/B/C-1, -2
- Plant Computer
- RVLIS
- Ultrasonic Level monitoring (optional)

Under the conditions specified by this EAL, continued lowering of Reactor Vessel water level is indicative of a loss of inventory control. Inventory loss may be due to a vessel breach, RCS pressure boundary leakage or continued boiling in the Reactor Vessel. The magnitude of this loss of water indicates that makeup systems have not been effective and may not be capable of preventing further RCS or Reactor Vessel water level drop and potential core uncovery. The inability to restore and maintain level after reaching this setpoint infers a failure of the RCS barrier and Potential Loss of the Fuel Clad barrier.

Three conditions are associated with a challenge to Containment integrity:

1. CONTAINMENT COSURE not established - The status of Containment closure is tracked if plant conditions change that could raise the risk of a fission product release as a result of a loss of decay heat removal (ref. 4, 5). If containment closure is re-established prior to exceeding the 30 minute core uncovery time limit then escalation to GE would not occur.
2. Containment hydrogen greater than 4% - The 4% hydrogen concentration threshold is generally considered the lower limit for hydrogen deflagrations. CPNPP is equipped with a Hydrogen Control System (HCS) which serves to limit or reduce combustible gas concentrations in the Containment. The plant has two hydrogen monitoring systems. Each monitoring system consists of four sensor modules and one microprocessor analyzer. Two sensors from each Containment are coupled to one of the two hydrogen microprocessors located in the Control Room. Thus each microprocessor analyzer is shared by Units 1 and 2. The analyzer system has a range of 0-10% hydrogen by volume. The detector modules are located on the 905’, 873’, and 860’ elevations in Containment. A fourth detector is located on 832’ level across from the loop room entrance for loops 1 and 4. Hydrogen concentration is displayed in the Control Room on u-AI-5506A/B and u-AI-5506C/D. Hydrogen concentration can also be displayed on the Plant Computer. Alarms at ~3% are provided for high hydrogen concentration, u-ALB-3A, window 3.7. If a hydrogen concentration value can not be obtained from the hydrogen monitoring system, a grab sample from the containment PIG radiation monitor may be used to determine the hydrogen concentration (ref. 6, 7, 8, 9).

3. UNPLANNED rise in Containment pressure - An unplanned pressure rise in containment while in cold Shutdown or Refueling modes can threaten Containment Closure capability and thus Containment potentially cannot be relied upon as a barrier to fission product release.

This IC addresses the inability to restore and maintain reactor vessel level above the top of active fuel with containment challenged. This condition represents actual or IMMINENT substantial core degradation or melting with potential for loss of containment integrity. Releases can be reasonably expected to exceed EPA PAG exposure levels offsite for more than the immediate site area.

Following an extended loss of core decay heat removal and inventory makeup, decay heat will cause reactor coolant boiling and a further reduction in reactor vessel level. If RCS level cannot be restored, fuel damage is probable.

With CONTAINMENT CLOSURE not established, there is a high potential for a direct and unmonitored release of radioactivity to the environment. If CONTAINMENT CLOSURE is re-established prior to exceeding the 30-minute time limit, then declaration of a General Emergency is not required.

The existence of an explosive mixture means, at a minimum, that the containment atmospheric hydrogen concentration is sufficient to support a hydrogen burn (i.e., at the lower deflagration limit). A hydrogen burn will raise containment pressure and could result in collateral equipment damage leading to a loss of containment integrity. It therefore represents a challenge to Containment integrity.

In the early stages of a core uncovery event, it is unlikely that hydrogen buildup due to a core uncovery could result in an explosive gas mixture in containment. If all installed hydrogen gas monitors are out-of-service during an event leading to fuel cladding damage, it may not be possible to obtain a containment hydrogen gas concentration reading as ambient conditions within the containment will preclude personnel access. During periods when installed containment hydrogen gas monitors are out-of-service, operators may use the other listed indications to assess whether or not containment is challenged.

The 30-minute criterion is tied to a readily recognizable event start time (i.e., the total loss of ability to monitor level), and allows sufficient time to monitor, assess and correlate reactor and plant conditions to determine if core uncovery has actually occurred (i.e., to account for various accident progression and instrumentation uncertainties). It also allows sufficient time for performance of actions to terminate leakage, recover inventory control/makeup equipment and/or restore level monitoring.

This EAL addresses concerns raised by Generic Letter 88-17, *Loss of Decay Heat Removal*; SECY 91-283, *Evaluation of Shutdown and Low Power Risk Issues*; NUREG-1449, *Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States*; and NUMARC 91-06, *Guidelines for Industry Actions to Assess Shutdown Management*.

CPNPP Basis Reference(s):

1. IPO-010A/B Reactor Coolant System Reduced Inventory Operations
2. INC-6269 Calibration of the Mansell RCS Measurement System
3. SOP-101A/B Reactor Coolant System
4. Technical Specifications 3.9.4
5. OPT-408A/B Refueling Containment Penetration Verification
6. FRC-0.1A/B Response to Inadequate Core Cooling, Attachment 5
7. FSAR Section 6.2.5
8. FSAR Table 7.5-7A
9. CHM-111 Primary Chemistry Accident Assessment Sampling Program
10. NEI 99-01 CS1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 1 – RCS Level

Initiating Condition: Loss of RCS inventory affecting fuel clad integrity with containment challenged

EAL:

CG1.2 General Emergency

RCS level **cannot** be monitored for greater than or equal to 30 min. (Note 1)

AND

Core uncovery is indicated by **any** of the following:

- UNPLANNED increase in **any** Table C-1 sump/tank level of sufficient magnitude to indicate core uncovery
- Erratic Source Range Monitor indication
- Greater than 20,000 R/hr on **any** of the following:

  - CTEu16, Containment HRRM (u-RE-6290A)
  - CTWu17, Containment HRRM (u-RE-6290B)

AND

Any Containment Challenge indication, Table C-2

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Note 6: If CONTAINMENT CLOSURE is re-established prior to exceeding the 30-minute time limit, declaration of a General Emergency is not required.

Table C-1 Sumps / Tanks
• Containment Sump 1
• Containment Sump 2
• Reactor Cavity Sump
• CCW Surge Tank A
• CCW Surge Tank B
• PRT
• RCDT

Table C-2 Containment Challenge Indications
• CONTAINMENT CLOSURE **not** established (Note 6)
• Containment hydrogen concentration greater than 4%
• Unplanned rise greater than 1 psig in Containment pressure

Mode Applicability:

5 - Cold Shutdown, 6 – Refueling

Definition(s):

CONTAINMENT CLOSURE - The procedurally defined actions taken to secure containment and its associated structures, systems, and components as a functional barrier to fission product release under shutdown conditions. Containment closure means that all potential escape paths are closed or capable of being closed:

A. All penetrations providing direct access from Containment atmosphere to outside atmosphere are closed except:
   - Penetrations with automatic valves capable of being closed by an operable CVI
   - Penetrations under administrative controls (e.g., Control Room notified and designated person to close if required by fuel handling accident)
B. Equipment hatch is closed and held in place by 4 bolts, or is capable of being closed and held in place by 4 bolts
C. One emergency airlock door is closed
D. One personnel airlock door is capable of being closed

UNISOLABLE - An open or breached system line that cannot be isolated, remotely or locally.

UNPLANNED-. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

In Cold Shutdown mode, the RCS will normally be intact and standard RCS level monitoring means are available.

In the Refueling mode, the RCS is not intact and RCS level may be monitored by different means, including the ability to monitor level visually.

In this EAL, all RCS water level indication would be unavailable for greater than 30 minutes, and the RCS inventory loss must be detected by indirect leakage indications (Table C-1). Surveillance procedures provide instructions for calculating primary system leak rate by manual or computer-based water inventory balances. Level increases must be evaluated against other potential sources of leakage such as cooling water sources inside the containment to ensure they are indicative of RCS leakage. If the make-up rate to the RCS unexplainably rises above the pre-established rate, a loss of RCS inventory may be occurring even if the source of the leakage cannot be immediately identified (ref. 1, 2).

The RCS inventory loss may be detected by the Containment High Range Radiation Monitor (HRRM) or erratic Source Range Monitor indication. As water level in the Reactor Vessel lowers, the dose rate above the core will rise. The dose rate due to this core shine should result in Containment High Range Radiation Monitor indication greater than 20,000 R/hr (ref. 3). The Containment HRRMs have a range of 1E-1 to 1E+8 R/hr.

Post-TMI accident studies indicated that the installed PWR nuclear instrumentation will operate erratically when the core is uncovered and that this should be used as a tool for making such determinations (ref. 4, 5).

Three conditions are associated with a challenge to Containment integrity:

1. CONTAINMENT COSURE not established - The status of Containment closure is tracked if plant conditions change that could raise the risk of a fission product release as a result of a loss of decay heat removal (ref. 6, 7). If containment closure is re-established prior to exceeding the 30 minute core uncovery time limit then escalation to GE would not occur.
2. Containment hydrogen greater than 4% - The 4% hydrogen concentration threshold is generally considered the lower limit for hydrogen deflagrations. CPNPP is equipped with a Hydrogen Control System (HCS) which serves to limit or reduce combustible gas concentrations in the Containment. The plant has two hydrogen monitoring systems. Each monitoring system consists of four sensor modules and one microprocessor analyzer. Two sensors from each Containment are coupled to one of the two hydrogen microprocessors located in the Control Room. Thus each microprocessor analyzer is shared by Units 1 and 2. The analyzer system has a range of 0-10% hydrogen by volume. The detector modules are located on the 905', 873', and 860' elevations in Containment. A fourth detector is located on 832' level across from the loop room entrance for loops 1 and 4. Hydrogen concentration is displayed in the Control Room on u-AI-5506A/B and u-AI-5506C/D. Hydrogen concentration can also be displayed on the Plant Computer. Alarms at ~3% are provided for high hydrogen concentration, u-ALB-3A, window 3.7. If a hydrogen concentration value can not be obtained from the hydrogen monitoring system, a grab sample from the containment PIG radiation monitor may be used to determine the hydrogen concentration (ref. 8, 9, 10, 11).
3. UNPLANNED rise in Containment pressure - An unplanned pressure rise in containment while in cold Shutdown or Refueling modes can threaten Containment Closure capability and thus Containment potentially cannot be relied upon as a barrier to fission product release.

This IC addresses the inability to restore and maintain reactor vessel level above the top of active fuel with containment challenged. This condition represents actual or IMMINENT substantial core degradation or melting with potential for loss of containment integrity. Releases can be reasonably expected to exceed EPA PAG exposure levels offsite for more than the immediate site area.

Following an extended loss of core decay heat removal and inventory makeup, decay heat will cause reactor coolant boiling and a further reduction in reactor vessel level. If RCS level cannot be restored, fuel damage is probable.

With CONTAINMENT CLOSURE not established, there is a high potential for a direct and unmonitored release of radioactivity to the environment. If CONTAINMENT CLOSURE is re-established prior to exceeding the 30-minute time limit, then declaration of a General Emergency is not required.

The existence of an explosive mixture means, at a minimum, that the containment atmospheric hydrogen concentration is sufficient to support a hydrogen burn (i.e., at the lower deflagration limit). A hydrogen burn will raise containment pressure and could result in collateral equipment damage leading to a loss of containment integrity. It therefore represents a challenge to Containment integrity.

In the early stages of a core uncovery event, it is unlikely that hydrogen buildup due to a core uncovery could result in an explosive gas mixture in containment. If all installed hydrogen gas monitors are out-of-service during an event leading to fuel cladding damage, it may not be possible to obtain a containment hydrogen gas concentration reading as ambient conditions within the containment will preclude personnel access. During periods when installed containment hydrogen gas monitors are out-of-service, operators may use the other listed indications to assess whether or not containment is challenged.

The 30-minute criterion is tied to a readily recognizable event start time (i.e., the total loss of ability to monitor level), and allows sufficient time to monitor, assess and correlate reactor and plant conditions to determine if core uncovery has actually occurred (i.e., to account for various accident progression and instrumentation uncertainties). It also allows sufficient time for performance of actions to terminate leakage, recover inventory control/makeup equipment and/or restore level monitoring.

The inability to monitor RCS level may be caused by instrumentation and/or power failures, or water level dropping below the range of available instrumentation. If water level cannot be monitored, operators may determine that an inventory loss is occurring by observing changes in sump and/or tank levels.

This EAL addresses concerns raised by Generic Letter 88-17, *Loss of Decay Heat Removal*; SECY 91-283, *Evaluation of Shutdown and Low Power Risk Issues*; NUREG-1449, *Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States*; and NUMARC 91-06, *Guidelines for Industry Actions to Assess Shutdown Management*.

CPNPP Basis Reference(s):

1. ABN-103 Excessive Reactor Coolant Leakage
2. ABN-108 Shutdown Loss of Coolant
3. Engineering Handbook, Guidelines for Events Beyond Design Basis: Spent Fuel Pools, Figure D “Dose Rate at Elevation 860’ above Stored Fuel vs. Water Level Depth in SFP”
4. Severe Accident Management Guidance Technical Basis Report, Volume 1: Candidate High-Level Actions and Their Effects, pgs 2-18, 2-19
5. Nuclear Safety Analysis Center (NSAC), 1980, “Analysis of Three Mile Island - Unit 2 Accident,” NSAC-1
6. Technical Specifications 3.9.4
7. OPT-408A/B Refueling Containment Penetration Verification
8. FRC-0.1A/B Response to Inadequate Core Cooling, Attachment 5
9. FSAR Section 6.2.5
10. FSAR Table 7.5-7A
11. CHM-111 Primary Chemistry Accident Assessment Sampling Program
12. NEI 99-01 CG1

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 2 – Loss of Emergency AC Power

Initiating Condition: Loss of **all but one** AC power source to safeguard buses for 15 minutes or longer

EAL:

CU2.1 Unusual Event

AC power capability, Table C-3, to 6.9 KV safeguard buses uEA1 and uEA2 reduced to a single power source for greater than or equal to 15 min. (Note 1)

AND

Any additional single Table C-3 power source failure will result in loss of **all** AC power to SAFETY SYSTEMS

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table C-3 AC Power Sources
Offsite: • 138 KV switchyard circuit • 345 KV switchyard circuit **Onsite:** • uEG1 • uEG2

Mode Applicability:

5 - Cold Shutdown, 6 – Refueling, D - Defueled

Definition(s):

SAFETY SYSTEM - A system required for safe plant operation, cooling down the plant and/or placing it in the cold shutdown condition, including the ECCS. These are typically systems classified as safety-related (as defined in 10CFR50.2):

Those structures, systems and components that are relied upon to remain functional during and following design basis events to assure:

(1) The integrity of the reactor coolant pressure boundary;

(2) The capability to shut down the reactor and maintain it in a safe shutdown condition;

(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures.

Basis:

For emergency classification purposes, “capability” means that an offsite AC power source(s) is available to the emergency buses, whether or not the buses are powered from it.

The condition indicated by this EAL is the degradation of the offsite and onsite power sources such that any additional single failure would result in a loss of all AC power to the emergency buses.

The safeguards AC distribution system power sources consist of the preferred and alternate offsite power sources, and the onsite standby emergency diesel generators uEG1 and uEG2. Offsite power is supplied to the plant switchyards from the transmission network by five 345 KV and two 138 KV transmission lines. From the switchyards, two electrically and physically separated circuits provide AC power through step down startup transformers, to the 6.9 kV safeguard buses. The 138 kV switchyard circuit is the preferred source for Unit 2 and alternate source for Unit 1. The 345 KV circuit is the preferred source for Unit 1 and alternate source for Unit 2. The onsite AC distribution system is divided into redundant trains so that the loss of any one load group does not prevent the minimum safety functions from being performed. Each train has connections to two offsite power sources and a dedicated diesel generator. Each offsite circuit can supply the Unit 1 and Unit 2 6.9 KV safeguard buses. (ref. 1, 2, 3, 4).

This cold condition EAL is equivalent to the hot condition EAL SA1.1.

This IC describes a significant degradation of offsite and onsite AC power sources such that any additional single failure would result in a loss of all AC power to SAFETY SYSTEMS. In this condition, the sole AC power source may be powering one, or more than one, train of safety-related equipment.

When in the cold shutdown, refueling, or defueled mode, this condition is not classified as an Alert because of the increased time available to restore another power source to service. Additional time is available due to the reduced core decay heat load, and the lower temperatures and pressures in various plant systems. Thus, when in these modes, this condition is considered to be a potential degradation of the level of safety of the plant.

An “AC power source” is a source recognized in AOPs and EOPs, and capable of supplying required power to an essential bus. Some examples of this condition are presented below.

- A loss of all offsite power with a concurrent failure of all but one emergency power source (e.g., an onsite diesel generator).
- A loss of all offsite power and loss of all emergency power sources (e.g., onsite diesel generators) with a single train of emergency buses being back-fed from the unit main generator.
- A loss of emergency power sources (e.g., onsite diesel generators) with a single train of emergency buses being back-fed from an offsite power source.

Fifteen minutes was selected as a threshold to exclude transient or momentary losses of power.

The subsequent loss of the remaining single power source would escalate the event to an Alert in accordance with IC CA2.

CPNPP Basis Reference(s):

1. FSAR Figure 8.3-1
2. FSAR Section 8.2
3. FSAR Section 8.3
4. Technical Specifications B3.8.1
5. ABN-601 Response to a 138/345 KV System Malfunction
6. ABN-602 Response to a 6900/480V System Malfunction
7. NEI 99-01 CU2

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 2 – Loss of Emergency AC Power

Initiating Condition: Loss of **all** offsite and **all** onsite AC power to safeguard buses for 15 minutes or longer

EAL:

CA2.1 Alert
Loss of **all** offsite and **all** onsite AC power capability, Table C-3, to 6.9 KV safeguard buses uEA1 and uEA2 for greater than or equal to 15 min. (Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table C-3 AC Power Sources
Offsite: • 138 KV switchyard circuit • 345 KV switchyard circuit **Onsite:** • uEG1 • uEG2

Mode Applicability:

5 - Cold Shutdown, 6 - Refueling, D - Defueled

Basis:

For emergency classification purposes, “capability” means that an offsite AC power source(s) is available to the emergency buses, whether or not the buses are powered from it.

The safeguards AC distribution system power sources consist of the preferred and alternate offsite power sources, and the onsite standby emergency diesel generators uEG1 and uEG2. Offsite power is supplied to the plant switchyards from the transmission network by five 345 KV and two 138 KV transmission lines. From the switchyards, two electrically and physically separated circuits provide AC power through step down startup transformers, to the 6.9 kV safeguard buses. The 138 kV switchyard circuit is the preferred source for Unit 2 and alternate source for Unit 1. The 345 KV circuit is the preferred source for Unit 1 and alternate source for Unit 2. The onsite AC distribution system is divided into redundant trains so that the loss of any one load group does not prevent the minimum safety functions from being performed. Each train has connections to two offsite power sources and a dedicated diesel generator. Each offsite circuit can supply the Unit 1 and Unit 2 6.9 KV safeguard buses. (ref. 1, 2, 3, 4)

This cold condition EAL is equivalent to the hot condition loss of all offsite AC power EAL SS1.1.

This IC addresses a total loss of AC power that compromises the performance of all SAFETY SYSTEMS requiring electric power including those necessary for emergency core cooling, containment heat removal/pressure control, spent fuel heat removal and the ultimate heat sink.

When in the cold shutdown, refueling, or defueled mode, this condition is not classified as a Site Area Emergency because of the increased time available to restore an emergency bus to service. Additional time is available due to the reduced core decay heat load, and the lower temperatures and pressures in various plant systems. Thus, when in these modes, this condition represents an actual or potential substantial degradation of the level of safety of the plant.

Fifteen minutes was selected as a threshold to exclude transient or momentary power losses.

Escalation of the emergency classification level would be via IC CS1 or RS1.

CPNPP Basis Reference(s):

1. FSAR Figure 8.3-1
2. FSAR Section 8.2
3. FSAR Section 8.3
4. Technical Specifications B3.8.1
5. ABN-601 Response to a 138/345 KV System Malfunction
6. ABN-602 Response to a 6900/480V System Malfunction
7. NEI 99-01 CA2

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 3 – RCS Temperature

Initiating Condition: UNPLANNED increase in RCS temperature

EAL:

CU3.1	**Unusual Event**
UNPLANNED increase in RCS temperature to greater than 200°F (Note 9)	

Note 9: Begin monitoring hot condition EALs concurrently.

Mode Applicability:

5 - Cold Shutdown, 6 - Refueling

Definition(s):

UNPLANNED-. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

Several instruments are capable of providing indication of RCS temperature with respect to the Technical Specification cold shutdown temperature limit (200°F, ref. 1). These include loop T_{hot} (u-TR-413A/23A, u -TR-433A/43A, u -TI-413A, u -TI-423A) and, if no RCPs are operating, the Core Exit Thermocouples (TCs). The most limiting temperature indication should be used. For example, during heatup, the highest reading temperature indication should be used; during cooldown, the lowest (ref. 2, 3, 4, 5).

In the absence of reliable RCS temperature indication caused by the loss of decay heat removal capability, classification should be based on time to boil data.

The note is a reminder that any temperature increase above 200ºF is an operating mode change from cold to hot conditions. Since each EAL is associated with operating mode applicability, the set of EALs that must be monitored must now include EALs associated with hot condition operating modes.

This IC addresses an UNPLANNED increase in RCS temperature above the Technical Specification cold shutdown temperature limitand represents a potential degradation of the level of safety of the plant. If the RCS is not intact and CONTAINMENT CLOSURE is not established during this event, the Emergency Coordinator should also refer to IC CA3.

A momentary UNPLANNED excursion above the Technical Specification cold shutdown temperature limit when the heat removal function is available does not warrant a classification.

This EAL involves a loss of decay heat removal capability, or an addition of heat to the RCS in excess of that which can currently be removed, such that reactor coolant temperature cannot be maintained below the cold shutdown temperature limit specified in Technical Specifications. During this condition, there is no immediate threat of fuel damage because the core decay heat load has been reduced since the cessation of power operation.

During an outage, the level in the reactor vessel will normally be maintained at or above the reactor vessel flange. Refueling evolutions that lower water level below the reactor vessel flange are carefully planned and controlled. A loss of forced decay heat removal at reduced inventory may result in a rapid increase in reactor coolant temperature depending on the time after shutdown.

Escalation to Alert would be via IC CA1 based on an inventory loss or IC CA3 based on exceeding plant configuration-specific time criteria.

CPNPP Basis Reference(s):

1. Technical Specifications Table 1.1-1
2. IPO-005A/B Plant Cooldown From Hot Standby To Cold Shutdown
3. Technical Specifications 3.4.3
4. OPT-407 RCS Pressure and Temperature Verification
5. IPO-010A/B Reactor Coolant System Reduced Inventory Condition
6. NEI 99-01 CU3

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 3 – RCS Temperature

Initiating Condition: UNPLANNED increase in RCS temperature

EAL:

CU3.2	**Unusual Event**
Loss of **all** RCS temperature and RCS level indication for greater than or equal to 15 min. (Note 1)	

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

5 - Cold Shutdown, 6- Refueling

Definition(s):

None

Basis:

RCS level can be monitored by one or more of the following (ref. 2, 3, 4):

- RCS Level Wide Range u-LI-3615B
- RCS Level Narrow Range u-LI-3615A
- RCS Extended Wide Range u-LI-3615C
- Mansell Level Monitor System u-LT-3619A/B/C-1, -2
- Plant Computer
- RVLIS
- Ultrasonic Level monitoring (optional)

Several instruments are capable of providing indication of RCS temperature with respect to the Technical Specification cold shutdown temperature limit (200°F, ref. 1). These include loop T_{hot} (u-TR-413A/23A, u -TR-433A/43A, u -TI-413A, u -TI-423A) and, if no RCPs are operating, the Core Exit Thermocouples (TCs). The most limiting temperature indication should be used. For example, during heatup, the highest reading temperature indication should be used; during cooldown, the lowest (ref. 5, 6, 7, 8).

In the absence of reliable RCS temperature indication caused by the loss of decay heat removal capability, classification should be based on time to boil data .

This EAL addresses the inability to determine RCS temperature and level, and represents a potential degradation of the level of safety of the plant. If the RCS is not intact and CONTAINMENT CLOSURE is not established during this event, the Emergency Coordinator should also refer to IC CA3.

This EAL reflects a condition where there has been a significant loss of instrumentation capability necessary to monitor RCS conditions and operators would be unable to monitor key parameters necessary to assure core decay heat removal. During this condition, there is no immediate threat of fuel damage because the core decay heat load has been reduced since the cessation of power operation.

Fifteen minutes was selected as a threshold to exclude transient or momentary losses of indication.

Escalation to Alert would be via IC CA1 based on an inventory loss or IC CA3 based on exceeding plant configuration-specific time criteria.

CPNPP Basis Reference(s):

1. Technical Specifications Table 1.1-1
2. IPO-010A/B Reactor Coolant System Reduced Inventory Operations
3. INC-6269 Calibration of the Mansell RCS Measurement System
4. SOP-101A/B Reactor Coolant System
5. IPO-005A/B Plant Cooldown From Hot Standby To Cold Shutdown
6. Technical Specifications 3.4.3
7. OPT-407 RCS Pressure and Temperature Verification
8. IPO-010A/B Reactor Coolant System Reduced Inventory Condition
9. NEI 99-01 CU3

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 3 – RCS Temperature

Initiating Condition: Inability to maintain plant in cold shutdown

EAL:

CA3.1 Alert

UNPLANNED increase in RCS temperature to greater than 200°F for greater than Table C-4 duration
(Notes 1, 9)

OR

UNPLANNED RCS pressure increase greater than 10 psig (This EAL does not apply during water-solid plant conditions)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that the applicable time has been exceeded, or will likely be exceeded.

Note 9: Begin monitoring hot condition EALs concurrently.

Table C-4: RCS Heat-up Duration Thresholds		
RCS Status	**CONTAINMENT CLOSURE Status**	**Heat-up Duration**
Intact (but **not** REDUCED INVENTORY)	N/A	60 min.*
Not intact **OR** REDUCED INVENTORY	Established	20 min.*
	Not established	0 min.
* If an RCS heat removal system is in operation within this time frame and RCS temperature is being reduced, the EAL is **not** applicable.		

Mode Applicability:

5 - Cold Shutdown, 6 – Refueling

Definition(s):

CONTAINMENT CLOSURE - The procedurally defined actions taken to secure containment and its associated structures, systems, and components as a functional barrier to fission product release under shutdown conditions. Containment closure means that all potential escape paths are closed or capable of being closed:

A. All penetrations providing direct access from Containment atmosphere to outside atmosphere are closed except:
   - Penetrations with automatic valves capable of being closed by an operable CVI
   - Penetrations under administrative controls (e.g., Control Room notified and designated person to close if required by fuel handling accident)

B. Equipment hatch is closed and held in place by 4 bolts, or is capable of being closed and held in place by 4 bolts
C. One emergency airlock door is closed
D. One personnel airlock door is capable of being closed

UNPLANNED -. A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

REDUCED INVENTORY - Plant condition when fuel is in the reactor vessel and Reactor Coolant System level is ≤ 80 inches above core plate (829’8”).

Basis:

Several instruments are capable of providing indication of RCS temperature with respect to the Technical Specification cold shutdown temperature limit (200°F, ref. 1). These include loop T_{hot} (u-TR-413A/23A, u -TR-433A/43A, u -TI-413A, u -TI-423A) and, if no RCPs are operating, the Core Exit Thermocouples (TCs). The most limiting temperature indication should be used. For example, during heatup, the highest reading temperature indication should be used; during cooldown, the lowest (ref. 2, 3, 4, 5).

In the absence of reliable RCS temperature indication caused by the loss of decay heat removal capability, classification should be based on heat up rate data or additionally if in Mode 5 with RCS intact on pressure increase.

A 10 psig RCS pressure increase can be monitored on u-PI-403A and computer points P6498A and P6499A (ref. 9, 10).

The status of Containment closure is tracked if plant conditions change that could raise the risk of a fission product release as a result of a loss of decay heat removal (ref. 6, 7).

The note is a reminder that any temperature increase above 200ºF is an operating mode change from cold to hot conditions. Since each EAL is associated with operating mode applicability, the set of EALs that must be monitored must now include EALs associated with hot condition operating modes.

This IC addresses conditions involving a loss of decay heat removal capability or an addition of heat to the RCS in excess of that which can currently be removed. Either condition represents an actual or potential substantial degradation of the level of safety of the plant.

A momentary UNPLANNED excursion above the Technical Specification cold shutdown temperature limit when the heat removal function is available does not warrant a classification.

The RCS Heat-up Duration Thresholds table addresses an increase in RCS temperature when CONTAINMENT CLOSURE is established but the RCS is not intact, or RCS inventory is reduced (e.g., mid-loop operation). The 20-minute criterion was included to allow time for operator action to address the temperature increase.

The RCS Heat-up Duration Thresholds table also addresses an increase in RCS temperature with the RCS intact. The status of CONTAINMENT CLOSURE is not crucial in this condition since the intact RCS is providing a high pressure barrier to a fission product release. The 60-minute time frame should allow sufficient time to address the temperature increase without a substantial degradation in plant safety.

Finally, in the case where there is an increase in RCS temperature, the RCS is not intact or is at reduced inventory, and CONTAINMENT CLOSURE is not established, no heat-up duration is allowed (i.e., 0 minutes). This is because 1) the evaporated reactor coolant may be released directly into the containment atmosphere and subsequently to the environment, and 2) there is reduced reactor coolant inventory above the top of irradiated fuel.

The RCS pressure increase threshold provides a pressure-based indication of RCS heat-up in the absence of RCS temperature monitoring capability.

Escalation of the emergency classification level would be via IC CS1 or RS1.

CPNPP Basis Reference(s):

1. Technical Specifications Table 1.1-1
2. IPO-005A/B Plant Cooldown From Hot Standby To Cold Shutdown
3. Technical Specifications 3.4.3
4. OPT-407 RCS Pressure and Temperature Verification
5. IPO-010A/B Reactor Coolant System Reduced Inventory Condition
6. Technical Specifications 3.9.4
7. OPT-408A/B Refueling Containment Penetration Verification
8. IPO-010A/B Reactor Coolant System Reduced Inventory Operations
9. IPO-005A/B Plant Cooldown From Hot Standby To Cold Shutdown
10. SOP-101A/B Reactor Coolant System Reduced Inventory
11. NEI 99-01 CA3

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 4 – Loss of Vital DC Power

Initiating Condition: Loss of vital DC power for 15 minutes or longer

EAL:

CU4.1	**Unusual Event**
Less than 105 VDC bus voltage indications on Technical Specification **required** 125 VDC buses (uED1, uED2, uED3, uED4) for greater than or equal to 15 min. (Note 1)	

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

5 - Cold Shutdown, 6 - Refueling

Definition(s):

None

Basis:

The purpose of this EAL is to recognize a loss of DC power compromising the ability to monitor and control the removal of decay heat during cold shutdown or refueling operations. This EAL is intended to be anticipatory in as much as the operating crew may not have necessary indication and control of equipment needed to respond to the loss. The fifteen minute interval is intended to exclude transient or momentary power losses.

The safeguards 125 VDC buses are the Class 1E buses uED1, uED2, uED3 and uED4 (ref. 1). The 125 VDC safeguard distribution system is illustrated in Figure C-2 (ref. 2, 3).

Each redundant safeguards 125 VDC system consists of two independent batteries each having one main distribution bus, two static battery chargers (one spare), and local distribution panels. For Unit 1, batteries BT1ED1 and BT1ED3 feed all train A load requirements, while batteries BT1ED2 and BT1ED4 supply train B load requirements.

For Unit 2, batteries BT2ED1 and BT2ED3 feed all train A load requirements, while batteries BT2ED2 and BT2ED4 supply train B load requirements. There are no bus ties or sharing of power supplies between redundant trains (ref. 1).

Minimum DC bus voltage is 105 VDC (ref. 4). Bus voltage may be monitored from the following indications (ref. 6):

Control Room Panel CP-10	Annunciator u--ALB-10B	Plant Computer
V-1ED1, 125VDC SWITCH PNL 1ED1 VOLT	1.13	V6501A BATT BT1ED1 VOLT
V-1ED2, 125VDC SWITCH PNL 1ED2 VOLT	2.13	V6502A BATT BT1ED2 VOLT
V-1ED3, 125VDC SWITCH PNL 1ED3 VOLT	1.9	V6503A BATT BT1ED3 VOLT
V-1ED4, 125VDC SWITCH PNL 1ED4 VOLT	3.9	V6504A BATT BT1ED4 VOLT

This EAL is the cold condition equivalent of the hot condition loss of DC power EAL SS2.1

This IC addresses a loss of vital DC power which compromises the ability to monitor and control operable SAFETY SYSTEMS when the plant is in the cold shutdown or refueling mode. In these modes, the core decay heat load has been significantly reduced, and coolant system temperatures and pressures are lower; these conditions increase the time available to restore a vital DC bus to service. Thus, this condition is considered to be a potential degradation of the level of safety of the plant.

As used in this EAL, "required" means the vital DC buses necessary to support operation of the in-service, or operable, train or trains of SAFETY SYSTEM equipment. For example, if Train A is out-of-service (inoperable) for scheduled outage maintenance work and Train B is in-service (operable), then a loss of Vital DC power affecting Train B would require the declaration of an Unusual Event. A loss of Vital DC power to Train A would not warrant an emergency classification.

Depending upon the event, escalation of the emergency classification level would be via IC CA1 or CA3, or an IC in Recognition Category R.

CPNPP Basis Reference(s):

1. FSAR 8.3.2
2. FSAR Figure 8.3-14
3. FSAR Figure 8.3-14A
4. ECA-0.0A/B Loss of All AC Power
5. SOP-605A/B 125 VDC Switchgear and Distribution Systems, Batteries and Battery Chargers
6. ALM-0102A/B Alarm Procedures Manual, u-ALB-10B, nos. 1.9, 1.13, 2.13, 3.8
7. NEI 99-01 CU4

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 5 – Loss of Communications

Initiating Condition: Loss of **all** onsite or offsite communications capabilities

EAL:

CU5.1 Unusual Event

Loss of **all** Table C-5 onsite communication methods

OR

Loss of **all** Table C-5 offsite communication methods

OR

Loss of **all** Table C-5 NRC communication methods

Table C-5 Communication Methods			
System	**Onsite**	**Offsite**	**NRC**
Gai-tronics Page/Party (PA)	X		
Plant Radios	X		
PABX	X	X	X
Public Telephone	X	X	X
Federal Telephone System (FTS)		X	X

Mode Applicability:

5 - Cold Shutdown, 6 - Refueling, D – Defueled

Definition(s):

None

Basis:

Onsite/offsite communications include one or more of the systems listed in Table C-5 (ref. 1, 2).

This EAL is the cold condition equivalent of the hot condition EAL SU7.1.

This IC addresses a significant loss of on-site or offsite communications capabilities. While not a direct challenge to plant or personnel safety, this event warrants prompt notifications to OROs and the NRC.

This IC should be assessed only when extraordinary means are being utilized to make communications possible (e.g., use of non-plant, privately owned equipment, relaying of on-site information via individuals or multiple radio transmission points, individuals being sent to offsite locations, etc.).

The first EAL condition addresses a total loss of the communications methods used in support of routine plant operations.

The second EAL condition addresses a total loss of the communications methods used to notify all OROs of an emergency declaration. The offsite (OROs) referred to here are the State Department of Public Safety, Somervell and Hood County EOCs

The third EAL addresses a total loss of the communications methods used to notify the NRC of an emergency declaration.

CPNPP Basis Reference(s):

1. FSAR 9.5.2
2. DBD-EE-048 Communication System
3. NEI 99-01 CU5

Category: C – Cold Shutdown / Refueling System Malfunction

Subcategory: 6 – Hazardous Event Affecting Safety Systems

Initiating Condition: Hazardous event affecting a SAFETY SYSTEM needed for the current operating mode

EAL:

CA6.1 Alert

The occurrence of **any** Table C-6 hazardous event

AND EITHER:

- Event damage has caused indications of degraded performance in at least one train of a SAFETY SYSTEM needed for the current operating mode
- The event has caused VISIBLE DAMAGE to a SAFETY SYSTEM component or structure needed for the current operating mode

Table C-6 Hazardous Events
● Seismic event (earthquake) ● Internal or external FLOODING event ● High winds or tornado strike ● FIRE ● EXPLOSION ● Other events with similar hazard characteristics as determined by the Emergency Coordinator

Mode Applicability:

5 - Cold Shutdown, 6 - Refueling

Definition(s):

EXPLOSION - A rapid, violent and catastrophic failure of a piece of equipment due to combustion, chemical reaction or overpressurization. A release of steam (from high energy lines or components) or an electrical component failure (caused by short circuits, grounding, arcing, etc.) should not automatically be considered an explosion. Such events require a post-event inspection to determine if the attributes of an explosion are present.

FIRE - Combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is NOT required if large quantities of smoke and heat are observed.

FLOODING - A condition where water is entering a room or area faster than installed equipment is capable of removal, resulting in a rise of water level within the room or area.

SAFETY SYSTEM - A system required for safe plant operation, cooling down the plant and/or placing it in the cold shutdown condition, including the ECCS. These are typically systems classified as safety-related (as defined in 10CFR50.2):

Those structures, systems and components that are relied upon to remain functional during and following design basis events to assure:

(1) The integrity of the reactor coolant pressure boundary;

(2) The capability to shut down the reactor and maintain it in a safe shutdown condition;

(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures.

VISIBLE DAMAGE - Damage to a component or structure that is readily observable without measurements, testing, or analysis. The visual impact of the damage is sufficient to cause concern regarding the operability or reliability of the affected component or structure.

Basis:

- The significance of seismic events are discussed under EAL HU2.1 (ref. 1).
- Internal FLOODING may be caused by events such as component failures, equipment misalignment, or outage activity mishaps (ref. 2).
- External flooding may be due to high lake level (ref. 3, 4).
- Seismic Category I structures are analyzed to withstand a sustained, design wind velocity of at least 80 mph. (ref. 5).
- Areas containing functions and systems required for safe shutdown of the plant are identified by fire area (ref. 6, 7).
- An explosion that degrades the performance of a SAFETY SYSTEM train or visibly damages a SAFETY SYSTEM component or structure would be classified under this EAL.

This IC addresses a hazardous event that causes damage to a SAFETY SYSTEM, or a structure containing SAFETY SYSTEM components, needed for the current operating mode. This condition significantly reduces the margin to a loss or potential loss of a fission product barrier, and therefore represents an actual or potential substantial degradation of the level of safety of the plant.

The first conditional addresses damage to a SAFETY SYSTEM train that is in service/operation since indications for it will be readily available. The indications of degraded performance should be significant enough to cause concern regarding the operability or reliability of the SAFETY SYSTEM train.

The second conditional addresses damage to a SAFETY SYSTEM component that is not in service/operation or readily apparent through indications alone, or to a structure containing SAFETY SYSTEM components. Operators will make this determination based on the totality of available event and damage report information. This is intended to be a brief assessment not requiring lengthy analysis or quantification of the damage.

Escalation of the emergency classification level would be via IC CS1 or RS1.

CPNPP Basis Reference(s):

1. ABN-907 Acts of Nature
2. CPNPP PRA Accident Sequence Analysis “Internal Flooding Sequences”
3. FSAR Section 2.4.3.7 Flood Evaluations for Safe Shutdown Impoundment
4. DBD-CS-071 Maximum Probable Flood
5. FSAR Section 3.3.1.1 Wind Loadings
6. CPNPP Fire Protection Report, Section 5.0 “Fire Safe Shutdown Equipment List”
7. FSAR Section 7.4 Systems Required for Safe Shutdown
8. NEI 99-01 CA6

Category H – Hazards and Other Conditions Affecting Plant Safety

EAL Group: ANY (EALs in this category are applicable to any plant condition, hot or cold.)

Hazards are non-plant, system-related events that can directly or indirectly affect plant operation, reactor plant safety or personnel safety.

1. Security

Unauthorized entry attempts into the Protected Area, bomb threats, sabotage attempts, and actual security compromises threatening loss of physical control of the plant.

2. Seismic Event

Natural events such as earthquakes have potential to cause plant structure or equipment damage of sufficient magnitude to threaten personnel or plant safety.

3. Natural or Technology Hazard

Other natural and non-naturally occurring events that can cause damage to plant facilities include tornados, FLOODING, hazardous material releases and events restricting site access warranting classification.

4. Fire

Fires can pose significant hazards to personnel and reactor safety. Appropriate for classification are fires within the site Protected Area or which may affect operability of equipment needed for safe shutdown

5. Hazardous Gas

Toxic, corrosive, asphyxiant or flammable gas leaks can affect normal plant operations or preclude access to plant areas required to safely shutdown the plant.

6. Control Room Evacuation

Events that are indicative of loss of Control Room habitability. If the Control Room must be evacuated, additional support for monitoring and controlling plant functions is necessary through the emergency response facilities.

7. Emergency Coordinator Judgment

The EALs defined in other categories specify the predetermined symptoms or events that are indicative of emergency or potential emergency conditions and thus warrant classification. While these EALs have been developed to address the full spectrum of possible emergency conditions which may warrant classification and subsequent implementation of the Emergency Plan, a provision for classification of emergencies based on operator/management experience and judgment is still necessary. The EALs of this category provide the Emergency Coordinator the latitude to classify emergency conditions consistent with the established classification criteria based upon Emergency Coordinator judgment.

Category: H – Hazards

Subcategory: 1 – Security

Initiating Condition: Confirmed SECURITY CONDITION or threat

EAL:

HU1.1	**Unusual Event**
A SECURITY CONDITION that does **not** involve a HOSTILE ACTION as reported by the Security Shift Supervisor	

Mode Applicability:

All

Definition(s):

SECURITY CONDITION - Any security event as listed in the approved security contingency plan that constitutes a threat/compromise to site security, threat/risk to site personnel, or a potential degradation to the level of safety of the plant. A security condition does not involve a hostile action.

HOSTILE ACTION - An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area).

Basis:

The security shift supervision is defined as the Security Shift Supervisor.

This EAL is based on the CPNPP Safeguards Contingency Plan (ref. 1).

This IC addresses events that pose a threat to plant personnel or SAFETY SYSTEM equipment, and thus represent a potential degradation in the level of plant safety. Security events which do not meet one of these EALs are adequately addressed by the requirements of 10 CFR § 73.71 or 10 CFR § 50.72. Security events assessed as HOSTILE ACTIONS are classifiable under ICs HA1, HS1 and HG1.

Timely and accurate communications between Security Shift Supervision and the Control Room is essential for proper classification of a security-related event. Classification of these events will initiate appropriate threat-related notifications to plant personnel and Offsite Response Organizations.

Security plans and terminology are based on the guidance provided by NEI 03-12, *Template for the Security Plan, Training and Qualification Plan, Safeguards Contingency Plan* .

This EAL references the Shift Security Supervisor because these are the individuals trained to confirm that a security event is occurring or has occurred. Training on security event confirmation and classification is controlled due to the nature of Safeguards and 10 CFR § 2.39 information.

Emergency plans and implementing procedures are public documents; therefore, EALs should not incorporate Security-sensitive information. This includes information that may be advantageous to a potential adversary, such as the particulars concerning a specific threat or threat location. Security-sensitive information should be contained in non-public documents such as the CPNPP Safeguards Contingency Plan (ref. 1).

Escalation of the emergency classification level would be via IC HA1.

CPNPP Basis Reference(s):

1. CPNPP Safeguards Contingency Plan (Safeguards)
2. NEI 99-01 HU1

Category: H – Hazards

Subcategory: 1 – Security

Initiating Condition: Confirmed SECURITY CONDITION or threat

EAL:

HU1.2	**Unusual Event**
Notification of a credible security threat directed at the site	

Mode Applicability:

All

Definition(s):

SECURITY CONDITION - Any security event as listed in the approved security contingency plan that constitutes a threat/compromise to site security, threat/risk to site personnel, or a potential degradation to the level of safety of the plant. A security condition does not involve a hostile action.

HOSTILE ACTION - An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area).

Basis:

The security shift supervision is defined as the Security Shift Supervisor.

This EAL is based on the CPNPP Safeguards Contingency Plan (ref. 1).

This IC addresses events that pose a threat to plant personnel or SAFETY SYSTEM equipment, and thus represent a potential degradation in the level of plant safety. Security events which do not meet one of these EALs are adequately addressed by the requirements of 10 CFR § 73.71 or 10 CFR § 50.72. Security events assessed as HOSTILE ACTIONS are classifiable under ICs HA1, HS1 and HG1.

Timely and accurate communications between Security Shift Supervision and the Control Room is essential for proper classification of a security-related event. Classification of these events will initiate appropriate threat-related notifications to plant personnel and Offsite Response Organizations.

Security plans and terminology are based on the guidance provided by NEI 03-12, *Template for the Security Plan, Training and Qualification Plan, Safeguards Contingency Plan* .

This EAL addresses the receipt of a credible security threat. The credibility of the threat is assessed in accordance with (site-specific procedure).

Emergency plans and implementing procedures are public documents; therefore, EALs should not incorporate Security-sensitive information. This includes information that may be advantageous to a potential adversary, such as the particulars concerning a specific threat or threat location. Security-sensitive information should be contained in non-public documents such as the CPNPP Safeguards Contingency Plan (ref. 1).

Escalation of the emergency classification level would be via IC HA1.

CPNPP Basis Reference(s):

1. CPNPP Safeguards Contingency Plan (Safeguards)
2. NEI 99-01 HU1

Category: H – Hazards

Subcategory: 1 – Security

Initiating Condition: Confirmed SECURITY CONDITION or threat

EAL:

HU1.3	**Unusual Event**
A validated notification from the NRC providing information of an aircraft threat	

Mode Applicability:

All

Definition(s):

None

Basis:

This EAL is based on the CPNPP Safeguards Contingency Plan (ref. 1).

This IC addresses events that pose a threat to plant personnel or SAFETY SYSTEM equipment, and thus represent a potential degradation in the level of plant safety. Security events which do not meet one of these EALs are adequately addressed by the requirements of 10 CFR § 73.71 or 10 CFR § 50.72. Security events assessed as HOSTILE ACTIONS are classifiable under ICs HA1, HS1 and HG1.

Timely and accurate communications between Security Shift Supervision and the Control Room is essential for proper classification of a security-related event. Classification of these events will initiate appropriate threat-related notifications to plant personnel and Offsite Response Organizations.

Security plans and terminology are based on the guidance provided by NEI 03-12, *Template for the Security Plan, Training and Qualification Plan, Safeguards Contingency Plan* .

This EAL addresses the threat from the impact of an aircraft on the plant. The NRC Headquarters Operations Officer (HOO) will communicate to the licensee if the threat involves an aircraft. The status and size of the plane may also be provided by NORAD through the NRC. Validation of the threat is performed in accordance with (site-specific procedure).

Emergency plans and implementing procedures are public documents; therefore, EALs should not incorporate Security-sensitive information. This includes information that may be advantageous to a potential adversary, such as the particulars concerning a specific threat or threat location. Security-sensitive information should be contained in non-public documents such as the CPNPP Safeguards Contingency Plan (ref. 1).

Escalation of the emergency classification level would be via IC HA1.

CPNPP Basis Reference(s):

1. CPNPP Safeguards Contingency Plan (Safeguards)
2. NEI 99-01 HU1

Category: H – Hazards

Subcategory: 1 – Security

Initiating Condition: HOSTILE ACTION within the OWNER CONTROLLED AREA or airborne attack threat within 30 minutes

EAL:

HA1.1	**Alert**
A HOSTILE ACTION is occurring or has occurred within the OWNER CONTROLLED AREA as reported by the Security Shift Supervisor	

Mode Applicability:

All

Definition(s):

HOSTILE ACTION - An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area).

OWNER CONTROLLED AREA - As shown in CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area.

Basis:

The security shift supervision is defined as the Security Shift Supervisor.

This IC addresses the occurrence of a HOSTILE ACTION within the OWNER CONTROLLED AREA. This event will require rapid response and assistance due to the possibility of the attack progressing to the PROTECTED AREA, or the need to prepare the plant and staff for a potential aircraft impact.

Timely and accurate communications between the Security Shift Supervisor and the Control Room is essential for proper classification of a security-related event.

Security plans and terminology are based on the guidance provided by NEI 03-12, *Template for the Security Plan, Training and Qualification Plan, Safeguards Contingency Plan*.

As time and conditions allow, these events require a heightened state of readiness by the plant staff and implementation of onsite protective measures (e.g., evacuation, dispersal or sheltering). The Alert declaration will also heighten the awareness of Offsite Response Organizations (OROs), allowing them to be better prepared should it be necessary to consider further actions.

This IC does not apply to incidents that are accidental events, acts of civil disobedience, or otherwise are not a HOSTILE ACTION perpetrated by a HOSTILE FORCE. Examples include the crash of a small aircraft, shots from hunters, physical disputes between employees, etc.

Reporting of these types of events is adequately addressed by other EALs, or the requirements of 10 CFR § 73.71 or 10 CFR § 50.72.

This EAL is applicable for any HOSTILE ACTION occurring, or that has occurred, in the OWNER CONTROLLED AREA. This includes any action directed against an ISFSI that is located outside the plant PROTECTED AREA.

Emergency plans and implementing procedures are public documents; therefore, EALs should not incorporate Security-sensitive information. This includes information that may be advantageous to a potential adversary, such as the particulars concerning a specific threat or threat location. Security-sensitive information should be contained in non-public documents such as the CPNPP Safeguards Contingency Plan (ref. 1).

CPNPP Basis Reference(s):

1. CPNPP Safeguards Contingency Plan (Safeguards)
2. NEI 99-01 HA1

Category: H – Hazards

Subcategory: 1 – Security

Initiating Condition: HOSTILE ACTION within the OWNER CONTROLLED AREA or airborne attack threat within 30 minutes

EAL:

HA1.2	**Alert**
A validated notification from NRC of an aircraft attack threat within 30 min. of the site	

Mode Applicability:

All

Definition(s):

None

Basis:

This IC addresses the occurrence of an aircraft attack threat. This event will require rapid response and assistance due to the possibility of the attack progressing to the PROTECTED AREA, or the need to prepare the plant and staff for a potential aircraft impact.

Timely and accurate communications between the Security Shift Supervisor and the Control Room is essential for proper classification of a security-related event.

Security plans and terminology are based on the guidance provided by NEI 03-12, *Template for the Security Plan, Training and Qualification Plan, Safeguards Contingency Plan*.

As time and conditions allow, these events require a heightened state of readiness by the plant staff and implementation of onsite protective measures (e.g., evacuation, dispersal or sheltering). The Alert declaration will also heighten the awareness of Offsite Response Organizations (OROs), allowing them to be better prepared should it be necessary to consider further actions.

This IC does not apply to incidents that are accidental events, acts of civil disobedience, or otherwise are not a HOSTILE ACTION perpetrated by a HOSTILE FORCE. Examples include the crash of a small aircraft, shots from hunters, physical disputes between employees, etc. Reporting of these types of events is adequately addressed by other EALs, or the requirements of 10 CFR § 73.71 or 10 CFR § 50.72.

This EAL addresses the threat from the impact of an aircraft on the plant, and the anticipated arrival time is within 30 minutes. The intent of this EAL is to ensure that threat-related notifications are made in a timely manner so that plant personnel and OROs are in a heightened state of readiness. This EAL is met when the threat-related information has been validated in accordance with site-specific security procedures.

The NRC Headquarters Operations Officer (HOO) will communicate to the licensee if the threat involves an aircraft. The status and size of the plane may be provided by NORAD through the NRC.

In some cases, it may not be readily apparent if an aircraft impact within the OWNER CONTROLLED AREA was intentional (i.e., a HOSTILE ACTION). It is expected, although not certain, that notification by an appropriate Federal agency to the site would clarify this point. In this case, the appropriate federal agency is intended to be NORAD, FBI, FAA or NRC. The emergency declaration, including one based on other ICs/EALs, should not be unduly delayed while awaiting notification by a Federal agency.

Emergency plans and implementing procedures are public documents; therefore, EALs should not incorporate Security-sensitive information. This includes information that may be advantageous to a potential adversary, such as the particulars concerning a specific threat or threat location. Security-sensitive information should be contained in non-public documents such as the CPNPP Safeguards Contingency Plan (ref. 1).

CPNPP Basis Reference(s):

1. CPNPP Safeguards Contingency Plan (Safeguards)
2. NEI 99-01 HA1

Category: H – Hazards

Subcategory: 1 – Security

Initiating Condition: HOSTILE ACTION within the PROTECTED AREA

EAL:

HS1.1	**Site Area Emergency**
A HOSTILE ACTION is occurring or has occurred within the PROTECTED AREA as reported by the Security Shift Supervisor	

Mode Applicability:

All

Definition(s):

HOSTILE ACTION - An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area).

PROTECTED AREA - An area encompassed by physical barriers and to which access is controlled. The Protected Area refers to the designated security area around the process buildings and is depicted in FSAR Figure 1.2-1 Plot Plan.

Basis:

The security shift supervision is defined as the Security Shift Supervisor.

These individuals are the designated on-site personnel qualified and trained to confirm that a security event is occurring or has occurred. Training on security event classification confirmation is closely controlled due to the strict secrecy controls placed on the CPNPP Safeguards Contingency Plan (Safeguards) information. (ref. 1)

This IC addresses the occurrence of a HOSTILE ACTION within the PROTECTED AREA. This event will require rapid response and assistance due to the possibility for damage to plant equipment.

Timely and accurate communications between Security Shift Supervision and the Control Room is essential for proper classification of a security-related event.

Security plans and terminology are based on the guidance provided by NEI 03-12, *Template for the Security Plan, Training and Qualification Plan, Safeguards Contingency Plan* .

As time and conditions allow, these events require a heightened state of readiness by the plant staff and implementation of onsite protective measures (e.g., evacuation, dispersal or sheltering). The Site Area Emergency declaration will mobilize Offsite Response Organization (ORO) resources and have them available to develop and implement public protective actions in the unlikely event that the attack is successful in impairing multiple safety functions.

This IC does not apply to a HOSTILE ACTION directed at an ISFSI PROTECTED AREA located outside the plant PROTECTED AREA; such an attack should be assessed using IC HA1. It also does not apply to incidents that are accidental events, acts of civil disobedience, or otherwise are not a HOSTILE ACTION perpetrated by a HOSTILE FORCE. Examples include the crash of a small aircraft, shots from hunters, physical disputes between employees, etc. Reporting of these types of events is adequately addressed by other EALs, or the requirements of 10 CFR § 73.71 or 10 CFR § 50.72.

Emergency plans and implementing procedures are public documents; therefore, EALs should not incorporate Security-sensitive information. This includes information that may be advantageous to a potential adversary, such as the particulars concerning a specific threat or threat location. Security-sensitive information should be contained in non-public documents such as the CPNPP Safeguards Contingency Plan (ref. 1).

Escalation of the emergency classification level would be via IC HG1.

CPNPP Basis Reference(s):

1. CPNPP Safeguards Contingency Plan (Safeguards)
2. NEI 99-01 HS1

Category: H – Hazards

Subcategory: 1 – Security

Initiating Condition: HOSTILE ACTION resulting in loss of physical control of the facility

EAL:

HG1.1 General Emergency

A HOSTILE ACTION is occurring or has occurred within the PROTECTED AREA as reported by the Security Shift Supervisor

AND EITHER of the following has occurred:

- One or more of the following safety functions cannot be controlled or maintained
  - Reactivity control
  - Core cooling
  - RCS heat removal

  OR
- Damage to spent fuel has occurred or is IMMINENT

Mode Applicability:

All

Definition(s):

HOSTILE ACTION - An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area).

IMMINENT - The trajectory of events or conditions is such that an EAL will be met within a relatively short period of time regardless of mitigation or corrective actions

PROTECTED AREA - An area encompassed by physical barriers and to which access is controlled. The Protected Area refers to the designated security area around the process buildings and is depicted in FSAR Figure 1.2-1 Plot Plan.

Basis:

The security shift supervision is defined as the Security Shift Supervisor.

This IC addresses an event in which a HOSTILE FORCE has taken physical control of the facility to the extent that the plant staff can no longer operate equipment necessary to maintain key safety functions. It also addresses a HOSTILE ACTION leading to a loss of physical control that results in actual or IMMINENT damage to spent fuel due to 1) damage to a spent fuel pool cooling system (e.g., pumps, heat exchangers, controls, etc.) or, 2) loss of spent fuel pool integrity such that sufficient water level cannot be maintained.

Timely and accurate communications between Security Shift Supervision and the Control Room is essential for proper classification of a security-related event.

Security plans and terminology are based on the guidance provided by NEI 03-12, *Template for the Security Plan, Training and Qualification Plan, Safeguards Contingency Plan* .

Emergency plans and implementing procedures are public documents; therefore, EALs should not incorporate Security-sensitive information. This includes information that may be advantageous to a potential adversary, such as the particulars concerning a specific threat or threat location. Security-sensitive information should be contained in non-public documents such as the CPNPP Safeguards Contingency Plan (ref.1).

CPNPP Basis Reference(s):

1. CPNPP Safeguards Contingency Plan (Safeguards)
2. NEI 99-01 HG1

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 2 – Seismic Event

Initiating Condition: Seismic event greater than OBE level

EAL:

HU2.1	**Unusual Event**
Seismic event greater than OBE as indicated by annunciator 2A-3.1, OBE EXCEEDED, or yellow OBE light on Seismic Monitoring system panel	

Mode Applicability:

All

Definition(s):

None

Basis:

Seismic events of this magnitude can result in a areas needed for safe shutdown being subjected to forces beyond design limits, and thus damage may be assumed to have occurred to plant safety systems.

A conservative Safe Shutdown Earthquake (SSE) having a peak horizontal ground acceleration at the top of bedrock of 0.12 g has been selected for design (FSAR Section 2.5.2.6). The Operating Basis Earthquake (OBE) is equal to ½ the SSE (ref. 1).

When the seismic recorder indicates that the OBE has been exceeded, System Engineering must evaluate and determine whether the reactor must be shut down and remain shutdown until inspection of the facility shows that no damage has been incurred which would jeopardize safe operation of the facility or until such damage is repaired. CPNPP was designed such that, for ground motion less than the OBE, the features of the plant necessary for continued operation without undue risk to the health and safety of the public will remain functional. Any ground motion in excess of this results in an uncertainty as to the extent of the damage which must be resolved before continued operation can be considered safe (ref. 2).

The seismic trigger, CP1-SIATAS-03, is set to activate the strong motion recording system at an acceleration level slightly above normal ambient vibrations (0.01g) and well below the postulated OBE “free field” ground acceleration (0.06g horizontal). This causes an alarm in the control room to alert the operator. (ref. 2, 3) The seismic recorders (strong motion accelerators) monitor earth vibration and, when triggered, store data in the recorder. Triaxial SMAs are installed at appropriate locations to provide data on the frequency, amplitude, and phase relationship of the seismic response of the containment structure and the seismic input to other seismic Category I structures, systems, and components. The Seismic Instrumentation consists of strong motion accelerograph (triaxial time history accelerograph system), triaxial peak accelerograph recorders, passive response spectrum recorders, a response spectrum switch, and a seismic switch. Except for sensors for the active instrumentation, all electronics for processing and storage of the seismic data are located in the seismic instrumentation panel CPX-ECPRCV-11 in the control room. There is no additional seismic instrumentation required for Unit 2. However, alarms from seismic instrumentation in Unit 1 are duplicated in Unit 2. The time history accelerograph system is fully operational within 0.1 second after the seismic trigger is actuated.

It will operate continuously during the period in which the earthquake exceeds the seismic trigger threshold (0.01g) plus 5 seconds (minimum) beyond the last seismic trigger signal.

ABN-907 Acts of Nature provides the guidance for determining if the OBE earthquake threshold is exceeded and any required response actions. (ref. 2)

To avoid inappropriate emergency classification resulting from spurious actuation of the seismic instrumentation or felt motion not attributable to seismic activity, an offsite agency (USGS, National Earthquake Information Center) can confirm that an earthquake has occurred in the area of the plant. Such confirmation should not, however, preclude a timely emergency declaration based on receipt of the OBE alarm. The NEIC can be contacted by calling **(303) 273-8500**. Select **option #1** and inform the analyst you wish to confirm recent seismic activity in the vicinity of CPNPP. Alternatively, near real-time seismic activity can be accessed via the NEIC website:

http://earthquake.usgs.gov

This IC addresses a seismic event that results in accelerations at the plant site greater than those specified for an Operating Basis Earthquake (OBE). An earthquake greater than an OBE but less than a Safe Shutdown Earthquake (SSE) should have no significant impact on safety-related systems, structures and components; however, some time may be required for the plant staff to ascertain the actual post-event condition of the plant (e.g., performs walk-downs and post-event inspections). Given the time necessary to perform walk-downs and inspections, and fully understand any impacts, this event represents a potential degradation of the level of safety of the plant.

Event verification with external sources should not be necessary during or following an OBE. Earthquakes of this magnitude should be readily felt by on-site personnel and recognized as a seismic event (e.g., lateral accelerations in excess of 0.08g). The Shift Manager or Emergency Coordinator may seek external verification if deemed appropriate (e.g., a call to the USGS, check internet news sources, etc.); however, the verification action must not preclude a timely emergency declaration.

Depending upon the plant mode at the time of the event, escalation of the emergency classification level would be via IC CA6 or SA9.

CPNPP Basis Reference(s):

1. FSAR Section 2.5.4.9 Earthquake Design Basis
2. ABN-907 Acts of Nature
3. DBD-EE-077 Seismic Instrumentation
4. 1, 2-ALB-2A-3.1 OBE EXCEEDED
5. DBD-ME-028 Classification of Structures, Systems and Components
6. NEI 99-01 HU2

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 3 – Natural or Technology Hazard

Initiating Condition: Hazardous event

EAL:

HU3.1	**Unusual Event**
A tornado strike within the PROTECTED AREA	

Mode Applicability:

All

Definition(s):

PROTECTED AREA - An area encompassed by physical barriers and to which access is controlled. The Protected Area refers to the designated security area around the process buildings and is depicted in FSAR Figure 1.2-1 Plot Plan.

Basis:

Response actions associated with a tornado onsite is provided in ABN-907 Acts of Nature (ref. 1).

If damage is confirmed visually or by other in-plant indications, the event may be escalated to an Alert under EAL CA6.1 or SA9.1.

A tornado striking (touching down) within the PROTECTED AREA warrants declaration of an Unusual Event regardless of the measured wind speed at the meteorological tower. A tornado is defined as a violently rotating column of air in contact with the ground and extending from the base of a thunderstorm.

This IC addresses hazardous events that are considered to represent a potential degradation of the level of safety of the plant.

EAL HU3.1 addresses a tornado striking (touching down) within the PROTECTED AREA.

Escalation of the emergency classification level would be based on ICs in Recognition Categories R, F, S or C.

CPNPP Basis Reference(s):

1. ABN-907 Acts of Nature
2. NEI 99-01 HU3

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 3 – Natural or Technology Hazard

Initiating Condition: Hazardous event

EAL:

HU3.2	**Unusual Event**
Internal room or area FLOODING of a magnitude sufficient to require manual or automatic electrical isolation of a SAFETY SYSTEM component needed for the current operating mode	

Mode Applicability:

All

Definition(s):

FLOODING - A condition where water is entering a room or area faster than installed equipment is capable of removal, resulting in a rise of water level within the room or area.

SAFETY SYSTEM - A system required for safe plant operation, cooling down the plant and/or placing it in the cold shutdown condition, including the ECCS. These are typically systems classified as safety-related (as defined in 10CFR50.2):

Those structures, systems and components that are relied upon to remain functional during and following design basis events to assure:

(1) The integrity of the reactor coolant pressure boundary;

(2) The capability to shut down the reactor and *maintain* it in a safe shutdown condition;

(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures.

Basis:

Refer to EAL CA6.1 or SA9.1 for internal flooding affecting one or more SAFETY SYSTEM trains.

This IC addresses hazardous events that are considered to represent a potential degradation of the level of safety of the plant.

This EAL addresses FLOODING of a building room or area that results in operators isolating power to a SAFETY SYSTEM component due to water level or other wetting concerns. Classification is also required if the water level or related wetting causes an automatic isolation of a SAFETY SYSTEM component from its power source (e.g., a breaker or relay trip). To warrant classification, operability of the affected component must be required by Technical Specifications for the current operating mode.

Escalation of the emergency classification level would be based on ICs in Recognition Categories R, F, S or C.

CPNPP Basis Reference(s):

1. CPNPP PRA Accident Sequence Analysis “Internal Flooding Sequences”
2. NEI 99-01 HU3

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 3 – Natural or Technology Hazard

Initiating Condition: Hazardous event

EAL:

HU3.3	**Unusual Event**
Movement of personnel within the PROTECTED AREA is IMPEDED due to an offsite event involving hazardous materials (e.g., an offsite chemical spill or toxic gas release)	

Mode Applicability:

All

Definition(s):

IMPEDE(D) - Personnel access to a room or area is hindered to an extent that extraordinary measures are necessary to facilitate entry of personnel into the affected room/area (e.g., requiring use of protective equipment, such as SCBAs, that is not routinely employed).

PROTECTED AREA - An area encompassed by physical barriers and to which access is controlled. The Protected Area refers to the designated security area around the process buildings and is depicted in FSAR Figure 1.2-1 Plot Plan.

Basis:

As used here, the term "offsite" is meant to be areas external to the CPNPP PROTECTED AREA.

This IC addresses hazardous events that are considered to represent a potential degradation of the level of safety of the plant.

This EAL addresses a hazardous materials event originating at an offsite location and of sufficient magnitude to impede the movement of personnel within the PROTECTED AREA.

Escalation of the emergency classification level would be based on ICs in Recognition Categories R, F, S or C.

CPNPP Basis Reference(s):

1. NEI 99-01 HU3

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 3 – Natural or Technology Hazard

Initiating Condition: Hazardous event

EAL:

HU3.4	**Unusual Event**
A hazardous event that results in on-site conditions sufficient to prohibit the plant staff from accessing the site via personal vehicles (Note 7)	

Note 7: This EAL does not apply to routine traffic impediments such as fog, snow, ice, or vehicle breakdowns or accidents.

Mode Applicability:

All

Definition(s):

None

Basis:

This IC addresses hazardous events that are considered to represent a potential degradation of the level of safety of the plant.

This EAL addresses a hazardous event that causes an on-site impediment to vehicle movement and significant enough to prohibit the plant staff from accessing the site using personal vehicles. Examples of such an event include site FLOODING caused by a hurricane, heavy rains, up-river water releases, dam failure, etc., or an on-site train derailment blocking the access road.

This EAL is not intended to apply to routine impediments such as fog, snow, ice, or vehicle breakdowns or accidents, but rather to more significant conditions such as the Hurricane Andrew strike on Turkey Point in 1992, the flooding around the Cooper Station during the Midwest floods of 1993, or the flooding around Ft. Calhoun Station in 2011.

Escalation of the emergency classification level would be based on ICs in Recognition Categories R, F, S or C.

CPNPP Basis Reference(s):

1. NEI 99-01 HU3

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 4 – Fire

Initiating Condition: FIRE potentially degrading the level of safety of the plant

EAL:

HU4.1 Unusual Event

A FIRE is **not** extinguished within 15 min. of **any** of the following FIRE detection indications (Note 1):

- Report from the field (i.e., visual observation)
- Receipt of multiple (more than 1) fire alarms or indications
- Field verification of a single fire alarm

AND

The FIRE is located within **any** Table H-1 area

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table H-1 Fire Areas
• u-Containment • u-Safeguards Building • X-Auxiliary Building • X-Electrical & Control Building • X-Fuel Building • X-Service Water Intake Structure • u-Diesel Generator Building • u-Normal Switchgear Rooms • u-CST • u-RWST

Mode Applicability:

All

Definition(s):

FIRE - Combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is NOT required if large quantities of smoke and heat are observed.

Basis:

The 15 minute requirement begins with a credible notification that a fire is occurring, or receipt of multiple valid fire detection system alarms or field validation of a single fire alarm. The alarm is to be validated using available Control Room indications or alarms to prove that it is not spurious, or by reports from the field. Actual field reports must be made within the 15 minute time limit or a classification must be made. If a fire is verified to be occurring by field report, the 15 minute time limit is from the original receipt of the fire detection alarm.

Table H-1 applies to buildings and areas housing equipment needed for safe shutdown (SAFETY SYSTEMS) (ref. 1, 2).

This IC addresses the magnitude and extent of FIRES that may be indicative of a potential degradation of the level of safety of the plant.

For EAL HU4.1 the intent of the 15-minute duration is to size the FIRE and to discriminate against small FIRES that are readily extinguished (e.g., smoldering waste paper basket). In addition to alarms, other indications of a FIRE could be a drop in fire main pressure, automatic activation of a suppression system, etc.

Upon receipt, operators will take prompt actions to confirm the validity of an initial fire alarm, indication, or report. For EAL assessment purposes, the emergency declaration clock starts at the time that the initial alarm, indication, or report was received, and not the time that a subsequent verification action was performed. Similarly, the fire duration clock also starts at the time of receipt of the initial alarm, indication or report.

<u>Basis-Related Requirements from Appendix R</u>

Appendix R to 10 CFR 50, states in part:

> Criterion 3 of Appendix A to this part specifies that "Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions."
>
> When considering the effects of fire, those systems associated with achieving and maintaining safe shutdown conditions assume major importance to safety because damage to them can lead to core damage resulting from loss of coolant through boil-off.
>
> Because fire may affect safe shutdown systems and because the loss of function of systems used to mitigate the consequences of design basis accidents under post-fire conditions does not per se impact public safety, the need to limit fire damage to systems required to achieve and maintain safe shutdown conditions is greater than the need to limit fire damage to those systems required to mitigate the consequences of design basis accidents.

Depending upon the plant mode at the time of the event, escalation of the emergency classification level would be via IC CA6 or SA9.

CPNPP Basis Reference(s):

1. CPNPP Fire Protection Report, Section 5.0 “Fire Safe Shutdown Equipment List”
2. FSAR Section 7.4 Systems Required for Safe Shutdown
3. NEI 99-01 HU4

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 4 – Fire

Initiating Condition: FIRE potentially degrading the level of safety of the plant

EAL:

HU4.2 **Unusual Event**
Receipt of a single fire alarm (i.e., **no** other indications of a FIRE)
AND
The fire alarm is indicating a FIRE within **any** Table H-1 area
AND
The existence of a FIRE is **not** verified within 30 min. of alarm receipt (Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table H-1 Fire Areas
• u-Containment • u-Safeguards Building • X-Auxiliary Building • X-Electrical & Control Building • X-Fuel Building • X-Service Water Intake Structure • u-Diesel Generator Building • u-Normal Switchgear Rooms • u-CST • u-RWST

Mode Applicability:

All

Definition(s):

FIRE - Combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is NOT required if large quantities of smoke and heat are observed.

Basis:

The 30 minute requirement begins upon receipt of a single valid fire detection system alarm. The alarm is to be validated using available Control Room indications or alarms to prove that it is not spurious, or by reports from the field. Actual field reports must be made within the 30 minute time limit or a classification must be made. If a fire is verified to be occurring by field report, classification shall be made based on EAL HU4.1.

Table H-1 applies to buildings and areas housing equipment needed for safe shutdown (SAFETY SYSTEMS) (ref. 1, 2).

This IC addresses the magnitude and extent of FIRES that may be indicative of a potential degradation of the level of safety of the plant.

This EAL addresses receipt of a single fire alarm, and the existence of a FIRE is not verified (i.e., proved or disproved) within 30-minutes of the alarm. Upon receipt, operators will take prompt actions to confirm the validity of a single fire alarm. For EAL assessment purposes, the 30-minute clock starts at the time that the initial alarm was received, and not the time that a subsequent verification action was performed.

A single fire alarm, absent other indication(s) of a FIRE, may be indicative of equipment failure or a spurious activation, and not an actual FIRE. For this reason, additional time is allowed to verify the validity of the alarm. The 30-minute period is a reasonable amount of time to determine if an actual FIRE exists; however, after that time, and absent information to the contrary, it is assumed that an actual FIRE is in progress.

If an actual FIRE is verified by a report from the field, then HU4.1 is immediately applicable, and the emergency must be declared if the FIRE is not extinguished within 15-minutes of the report. If the alarm is verified to be due to an equipment failure or a spurious activation, and this verification occurs within 30-minutes of the receipt of the alarm, then this EAL is not applicable and no emergency declaration is warranted.

<u>Basis-Related Requirements from Appendix R</u>

Appendix R to 10 CFR 50, states in part:

> Criterion 3 of Appendix A to this part specifies that "Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions."
>
> When considering the effects of fire, those systems associated with achieving and maintaining safe shutdown conditions assume major importance to safety because damage to them can lead to core damage resulting from loss of coolant through boil-off.
>
> Because fire may affect safe shutdown systems and because the loss of function of systems used to mitigate the consequences of design basis accidents under post-fire conditions does not per se impact public safety, the need to limit fire damage to systems required to achieve and maintain safe shutdown conditions is greater than the need to limit fire damage to those systems required to mitigate the consequences of design basis accidents.

In addition, Appendix R to 10 CFR 50, requires, among other considerations, the use of 1-hour fire barriers for the enclosure of cable and equipment and associated non-safety circuits of one redundant train (G.2.c). As used in HU4.2, the 30-minutes to verify a single alarm is well within this worst-case 1-hour time period.

Depending upon the plant mode at the time of the event, escalation of the emergency classification level would be via IC CA6 or SA9.

CPNPP Basis Reference(s):

1. CPNPP Fire Protection Report, Section 5.0 “Fire Safe Shutdown Equipment List”
2. FSAR Section 7.4 Systems Required for Safe Shutdown
3. NEI 99-01 HU4

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 4 – Fire

Initiating Condition: FIRE potentially degrading the level of safety of the plant

EAL:

HU4.3	**Unusual Event**
A FIRE within the ISFSI or plant PROTECTED AREA **not** extinguished within 60 min. of the initial report, alarm or indication (Note 1)	

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

All

Definition(s):

FIRE - Combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is NOT required if large quantities of smoke and heat are observed.

PROTECTED AREA - An area encompassed by physical barriers and to which access is controlled. The Protected Area refers to the designated security area around the process buildings and is depicted in FSAR Figure 1.2-1 Plot Plan.

Basis:

This IC addresses the magnitude and extent of FIRES that may be indicative of a potential degradation of the level of safety of the plant.

In addition to a FIRE addressed by EAL HU4.1 or HU4.2, a FIRE within the plant PROTECTED AREA not extinguished within 60-minutes may also potentially degrade the level of plant safety. This basis extends to a FIRE occurring within the PROTECTED AREA of an ISFSI located outside the plant PROTECTED AREA.

Depending upon the plant mode at the time of the event, escalation of the emergency classification level would be via IC CA6 or SA9.

CPNPP Basis Reference(s):

1. NEI 99-01 HU4

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 4 – Fire

Initiating Condition: FIRE potentially degrading the level of safety of the plant

EAL:

HU4.4	**Unusual Event**
A FIRE within the ISFSI or plant PROTECTED AREA that requires firefighting support by an offsite fire response agency to extinguish	

Mode Applicability:

All

Definition(s):

FIRE - Combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is NOT required if large quantities of smoke and heat are observed.

PROTECTED AREA - An area encompassed by physical barriers and to which access is controlled. The Protected Area refers to the designated security area around the process buildings and is depicted in FSAR Figure 1.2-1 Plot Plan.

Basis:

This IC addresses the magnitude and extent of FIRES that may be indicative of a potential degradation of the level of safety of the plant.

If a FIRE within the plant or ISFSI PROTECTED AREA is of sufficient size to require a response by an offsite firefighting agency (e.g., a local town Fire Department), then the level of plant safety is potentially degraded. The dispatch of an offsite firefighting agency to the site requires an emergency declaration only if it is needed to actively support firefighting efforts because the fire is beyond the capability of the Fire Brigade to extinguish. Declaration is not necessary if the agency resources are placed on stand-by, or supporting post-extinguishment recovery or investigation actions.

Depending upon the plant mode at the time of the event, escalation of the emergency classification level would be via IC CA6 or SA9.

CPNPP Basis Reference(s):

1. NEI 99-01 HU4

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 5 – Hazardous Gases

Initiating Condition: Gaseous release IMPEDING access to equipment necessary for normal plant operations, cooldown or shutdown

EAL:

HA5.1 Alert

Release of a toxic, corrosive, asphyxiant or flammable gas into **any** Table H-2 rooms or areas

AND

Entry into the room or area is prohibited or IMPEDED (Note 5)

Note 5: If the equipment in the listed room or area was already inoperable or out-of-service before the event occurred, then **no** emergency classification is warranted.

Table H-2 Safe Operation & Shutdown Rooms/Areas	
Room/Area	**Mode Applicability**
Charging Pump Rooms	1, 2, 3, 4, 5, 6
CVCS Valve Rooms	1, 2, 3, 4, 5, 6
1E Switchgear Rooms	All
RHR Pump Rooms	4, 5, 6

Mode Applicability:

All

Definition(s):

IMPEDE(D) - Personnel access to a room or area is hindered to an extent that extraordinary measures are necessary to facilitate entry of personnel into the affected room/area (e.g., requiring use of protective equipment, such as SCBAs, that is not routinely employed).

Basis:

If the equipment in the listed room or area was already inoperable, or out-of-service, before the event occurred, then no emergency should be declared since the event will have no adverse impact beyond that already allowed by Technical Specifications at the time of the event.

The list of plant rooms or areas with entry-related mode applicability identified specify those rooms or areas that contain equipment which require a manual/local action as specified in operating procedures used for normal plant operation, cooldown and shutdown. Rooms or areas in which actions of a contingent or emergency nature would be performed (e.g., an action to address an off-normal or emergency condition such as emergency repairs, corrective measures or emergency operations) are not included. In addition, the list specifies the plant mode(s) during which entry would be required for each room or area (ref. 1).

This IC addresses an event involving a release of a hazardous gas that precludes or impedes access to equipment necessary to maintain normal plant operation, or required for a normal plant cooldown and shutdown. This condition represents an actual or potential substantial degradation of the level of safety of the plant.

An Alert declaration is warranted if entry into the affected room/area is, or may be, procedurally required during the plant operating mode in effect at the time of the gaseous release. The emergency classification is not contingent upon whether entry is actually necessary at the time of the release.

Evaluation of the IC and EAL do not require atmospheric sampling; it only requires the Emergency Coordinator's judgment that the gas concentration in the affected room/area is sufficient to preclude or significantly impede procedurally required access. This judgment may be based on a variety of factors including an existing job hazard analysis, report of ill effects on personnel, advice from a subject matter expert or operating experience with the same or similar hazards. Access should be considered as impeded if extraordinary measures are necessary to facilitate entry of personnel into the affected room/area (e.g., requiring use of protective equipment, such as SCBAs, that is not routinely employed).

An emergency declaration is not warranted if any of the following conditions apply:

- The plant is in an operating mode different than the mode specified for the affected room/area (i.e., entry is not required during the operating mode in effect at the time of the gaseous release). For example, the plant is in Mode 1 when the gaseous release occurs, and the procedures used for normal operation, cooldown and shutdown do not require entry into the affected room until Mode 4.
- The gas release is a planned activity that includes compensatory measures which address the temporary inaccessibility of a room or area (e.g., fire suppression system testing).
- The action for which room/area entry is required is of an administrative or record keeping nature (e.g., normal rounds or routine inspections).
- The access control measures are of a conservative or precautionary nature, and would not actually prevent or impede a required action.

An asphyxiant is a gas capable of reducing the level of oxygen in the body to dangerous levels. Most commonly, asphyxiants work by merely displacing air in an enclosed environment. This reduces the concentration of oxygen below the normal level of around 19%, which can lead to breathing difficulties, unconsciousness or even death.

This EAL does not apply to firefighting activities that automatically or manually activate a fire suppression system in an area..

Escalation of the emergency classification level would be via Recognition Category R, C or F ICs.

CPNPP Basis Reference(s):

1. Attachment 3 Safe Operation & Shutdown Areas Tables R-3 & H-2 Bases
2. NEI 99-01 HA5

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 6 – Control Room Evacuation

Initiating Condition: Control Room evacuation resulting in transfer of plant control to alternate locations

EAL:

HA6.1	**Alert**
An event has resulted in plant control being transferred from the Control Room to the Remote Shutdown Panel (RSP)	

Mode Applicability:

All

Definition(s):

None

Basis:

Upon evacuation of the Control Room plant control is established at the Remote Shutdown Panel (RSP). ABN-905A/B “Loss of Control Room Habitability” and ABN-803A/B “Response to a Fire in the Control Room or Cable Spreading Room” provide the instructions for tripping the unit, and maintaining RCS inventory and Hot Shutdown conditions from outside the Control Room. The Shift Manager (SM) determines if the Control Room is inoperable and requires evacuation. Control Room inhabitability may be caused by fire, dense smoke, noxious fumes, bomb threat in or adjacent to the Control Room, or other life threatening conditions. (Ref. 1, 2, 3, 4, 5).

Inability to establish plant control from outside the Control Room escalates this event to a Site Area Emergency per EAL HS6.1.

This IC addresses an evacuation of the Control Room that results in transfer of plant control to alternate locations outside the Control Room. The loss of the ability to control the plant from the Control Room is considered to be a potential substantial degradation in the level of plant safety.

Following a Control Room evacuation, control of the plant will be transferred to alternate shutdown locations. The necessity to control a plant shutdown from outside the Control Room, in addition to responding to the event that required the evacuation of the Control Room, will present challenges to plant operators and other on-shift personnel. Activation of the ERO and emergency response facilities will assist in responding to these challenges.

Escalation of the emergency classification level would be via IC HS6.

CPNPP Basis Reference(s):

1. DBD-ME-003 Control Room Habitability
2. ABN-905A Loss of Control Room Habitability
3. ABN-905B Loss of Control Room Habitability
4. ABN-803A Response to a Fire in the Control Room or Cable Spreading Room
5. ABN-803B Response to a Fire in the Control Room or Cable Spreading Room
6. NEI 99-01 HA6

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 6 – Control Room Evacuation

Initiating Condition: Inability to control a key safety function from outside the Control Room

EAL:

HS6.1 Site Area Emergency

An event has resulted in plant control being transferred from the Control Room to the Remote Shutdown Panel (RSP)

AND

Control of **any** of the following key safety functions is **not** re-established within 15 min. (Note 1):

- Reactivity
- Core Cooling
- RCS heat removal

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

All

Definition(s):

None

Basis:

Upon evacuation of the Control Room plant control is established at the Remote Shutdown Panel (RSP). ABN-905A/B "Loss of Control Room Habitability" and ABN-803A/B "Response to a Fire in the Control Room or Cable Spreading Room" provide the instructions for tripping the unit, and maintaining RCS inventory and Hot Shutdown conditions from outside the Control Room. The Shift Manager (SM) determines if the Control Room is inoperable and requires evacuation. Control Room inhabitability may be caused by fire, dense smoke, noxious fumes, bomb threat in or adjacent to the Control Room, or other life threatening conditions. (Ref. 1, 2, 3, 4, 5).

The intent of this EAL is to capture events in which control of the plant cannot be reestablished in a timely manner. The fifteen minute time for transfer starts when the Control Room begins to be evacuated (not when the ABN is entered). The time interval is based on how quickly control must be reestablished without core uncovery and/or core damage. The determination of whether or not control is established from outside the Control Room is based on Emergency Coordinator judgment. The Emergency Coordinator is expected to make a reasonable, informed judgment that control of the plant from outside the Control Room cannot be established within the fifteen minute interval.

Once the Control Room is evacuated, the objective is to establish control of important plant equipment and maintain knowledge of important plant parameters in a timely manner. Primary emphasis should be placed on components and instruments that supply protection for and information about safety functions. Typically, these safety functions are reactivity control (ability to shutdown the reactor and maintain it shutdown), RCS inventory (ability to cool the core), and secondary heat removal (ability to maintain a heat sink).

This IC addresses an evacuation of the Control Room that results in transfer of plant control to alternate locations, and the control of a key safety function cannot be reestablished in a timely manner. The failure to gain control of a key safety function following a transfer of plant control to alternate locations is a precursor to a challenge to one or more fission product barriers within a relatively short period of time.

The determination of whether or not “control” is established at the remote safe shutdown location(s) is based on Emergency Coordinator judgment. The Emergency Coordinator is expected to make a reasonable, informed judgment within 15 minutes whether or not the operating staff has control of key safety functions from the remote safe shutdown location(s).

Escalation of the emergency classification level would be via IC FG1 or CG1

CPNPP Basis Reference(s):

1. DBD-ME-003 Control Room Habitability
2. ABN-905A Loss of Control Room Habitability
3. ABN-905B Loss of Control Room Habitability
4. ABN-803A Response to a Fire in the Control Room or Cable Spreading Room
5. ABN-803B Response to a Fire in the Control Room or Cable Spreading Room
6. NEI 99-01 HS6

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 7 – Emergency Coordinator Judgment

Initiating Condition: Other conditions existing that in the judgment of the Emergency Coordinator warrant declaration of a UE

EAL:

HU7.1	**Unusual Event**
Other conditions exist which in the judgment of the Emergency Coordinator indicate that events are in progress or have occurred which indicate a potential degradation of the level of safety of the plant or indicate a security threat to facility protection has been initiated. No releases of radioactive material requiring offsite response or monitoring are expected unless further degradation of SAFETY SYSTEMS occurs.	

Mode Applicability:

All

Definition(s):

SAFETY SYSTEM - A system required for safe plant operation, cooling down the plant and/or placing it in the cold shutdown condition, including the ECCS. These are typically systems classified as safety-related (as defined in 10CFR50.2):

Those structures, systems and components that are relied upon to remain functional during and following design basis events to assure:

(1) The integrity of the reactor coolant pressure boundary;

(2) The capability to shut down the reactor and *maintain* it in a safe shutdown condition;

(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures.

Basis:

The Emergency Coordinator is the designated onsite individual having the responsibility and authority for implementing the CPNPP Radiological Emergency Response Plan. The Shift Manager (SM) initially acts in the capacity of the Emergency Coordinator and takes actions as outlined in the Emergency Plan implementing procedures. If required by the emergency classification or if deemed appropriate by the Emergency Coordinator, emergency response personnel are notified and instructed to report to their emergency response locations. In this manner, the individual usually in charge of activities in the Control Room is responsible for initiating the necessary emergency response, but Plant Management is expected to manage the emergency response as soon as available to do so in anticipation of the possible wide-ranging responsibilities associated with managing a major emergency (ref. 1).

This IC addresses unanticipated conditions not addressed explicitly elsewhere but that warrant declaration of an emergency because conditions exist which are believed by the Emergency Coordinator to fall under the emergency classification level description for an Unusual Event.

CPNPP Basis Reference(s):

1. CPNPP Radiological Emergency Response Plan section 1.1.2 Response
2. NEI 99-01 HU7

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 7 – Emergency Coordinator Judgment

Initiating Condition: Other conditions exist that in the judgment of the Emergency Coordinator warrant declaration of an Alert

EAL:

HA7.1 Alert
Other conditions exist which, in the judgment of the Emergency Coordinator, indicate that events are in progress or have occurred which involve an actual or potential substantial degradation of the level of safety of the plant or a security event that involves probable life threatening risk to site personnel or damage to site equipment because of HOSTILE ACTION. Any releases are expected to be limited to small fractions of the EPA Protective Action Guideline exposure levels.

Mode Applicability:

All

Definition(s):

HOSTILE ACTION - An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area).

Basis:

The Emergency Coordinator is the designated onsite individual having the responsibility and authority for implementing the CPNPP Radiological Emergency Response Plan. The Shift Manager (SM) initially acts in the capacity of the Emergency Coordinator and takes actions as outlined in the Emergency Plan implementing procedures. If required by the emergency classification or if deemed appropriate by the Emergency Coordinator, emergency response personnel are notified and instructed to report to their emergency response locations. In this manner, the individual usually in charge of activities in the Control Room is responsible for initiating the necessary emergency response, but Plant Management is expected to manage the emergency response as soon as available to do so in anticipation of the possible wide-ranging responsibilities associated with managing a major emergency (ref. 1).

This IC addresses unanticipated conditions not addressed explicitly elsewhere but that warrant declaration of an emergency because conditions exist which are believed by the Emergency Coordinator to fall under the emergency classification level description for an Alert.

CPNPP Basis Reference(s):

1. CPNPP Radiological Emergency Response Plan section 1.1.2 Response
2. NEI 99-01 HA7

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 7 – Emergency Coordinator Judgment

Initiating Condition: Other conditions existing that in the judgment of the Emergency Coordinator warrant declaration of a Site Area Emergency

EAL:

HS7.1 Site Area Emergency

Other conditions exist which in the judgment of the Emergency Coordinator indicate that events are in progress or have occurred which involve actual or likely major failures of plant functions needed for protection of the public or HOSTILE ACTION that results in intentional damage or malicious acts, (1) toward site personnel or equipment that could lead to the likely failure of or, (2) that prevent effective access to equipment needed for the protection of the public. Any releases are not expected to result in exposure levels which exceed EPA Protective Action Guideline exposure levels beyond the EXCLUSION AREA BOUNDARY

Mode Applicability:

All

Definition(s):

EXCLUSION AREA BOUNDARY - Exclusion Area Boundary is a synonymous term for Site Boundary. CPNPP FSAR Section 2.1.1.3 and Figure 2.1-2 define the Exclusion Area Boundary. This boundary is used for establishing effluent release limits with respect to the requirements of 10CFR20. See also CPNPP Emergency Plan Appendix E, Complex and Owner Controlled Area and CCNPP ODCM Section 5.0 Design Features.

HOSTILE ACTION - An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area)

Basis:

The Emergency Coordinator is the designated onsite individual having the responsibility and authority for implementing the CPNPP Radiological Emergency Response Plan. The Shift Manager (SM) initially acts in the capacity of the Emergency Coordinator and takes actions as outlined in the Emergency Plan implementing procedures. If required by the emergency classification or if deemed appropriate by the Emergency Coordinator, emergency response personnel are notified and instructed to report to their emergency response locations. In this manner, the individual usually in charge of activities in the Control Room is responsible for initiating the necessary emergency response, but Plant Management is expected to manage the emergency response as soon as available to do so in anticipation of the possible wide-ranging responsibilities associated with managing a major emergency (ref. 1).

This IC addresses unanticipated conditions not addressed explicitly elsewhere but that warrant declaration of an emergency because conditions exist which are believed by the Emergency Coordinator to fall under the emergency classification level description for a Site Area Emergency.

CPNPP Basis Reference(s):

1. CPNPP Radiological Emergency Response Plan section 1.1.2 Response
2. NEI 99-01 HS7

Category: H – Hazards and Other Conditions Affecting Plant Safety

Subcategory: 7 – Emergency Coordinator Judgment

Initiating Condition: Other conditions exist which in the judgment of the Emergency Coordinator warrant declaration of a General Emergency

EAL:

HG7.1	**General Emergency**
Other conditions exist which in the judgment of the Emergency Coordinator indicate that events are in progress or have occurred which involve actual or IMMINENT substantial core degradation or melting with potential for loss of containment integrity or HOSTILE ACTION that results in an actual loss of physical control of the facility. Releases can be reasonably expected to exceed EPA Protective Action Guideline exposure levels offsite for more than the immediate site area	

Mode Applicability:

All

Definition(s):

HOSTILE ACTION - An act toward CPNPP or its personnel that includes the use of violent force to destroy equipment, take hostages, and/or intimidate the licensee to achieve an end. This includes attack by air, land, or water using guns, explosives, projectiles, vehicles, or other devices used to deliver destructive force. Other acts that satisfy the overall intent may be included. Hostile action should not be construed to include acts of civil disobedience or felonious acts that are not part of a concerted attack on CPNPP. Non-terrorism-based EALs should be used to address such activities (i.e., this may include violent acts between individuals in the owner controlled area).

IMMINENT - The trajectory of events or conditions is such that an EAL will be met within a relatively short period of time regardless of mitigation or corrective actions.

Basis:

The Emergency Coordinator is the designated onsite individual having the responsibility and authority for implementing the CPNPP Radiological Emergency Response Plan. The Shift Manager (SM) initially acts in the capacity of the Emergency Coordinator and takes actions as outlined in the Emergency Plan implementing procedures. If required by the emergency classification or if deemed appropriate by the Emergency Coordinator, emergency response personnel are notified and instructed to report to their emergency response locations. In this manner, the individual usually in charge of activities in the Control Room is responsible for initiating the necessary emergency response, but Plant Management is expected to manage the emergency response as soon as available to do so in anticipation of the possible wide-ranging responsibilities associated with managing a major emergency (ref. 1).

Releases can reasonably be expected to exceed EPA PAG plume exposure levels outside the Site Boundary.

This IC addresses unanticipated conditions not addressed explicitly elsewhere but that warrant declaration of an emergency because conditions exist which are believed by the Emergency Coordinator to fall under the emergency classification level description for a General Emergency.

CPNPP Basis Reference(s):

1. CPNPP Radiological Emergency Response Plan section 1.1.2 Response
2. NEI 99-01 HG7

Category S – System Malfunction

EAL Group: Hot Conditions (RCS temperature greater than 200ºF); EALs in this category are applicable only in one or more hot operating modes.

Numerous system-related equipment failure events that warrant emergency classification have been identified in this category. They may pose actual or potential threats to plant safety.

The events of this category pertain to the following subcategories:

1. Loss of Emergency AC Power

Loss of emergency electrical power can compromise plant safety system operability including decay heat removal and emergency core cooling systems which may be necessary to ensure fission product barrier integrity. This category includes loss of onsite and offsite sources for 6.9KV AC safeguard buses.

2. Loss of Vital DC Power

Loss of emergency electrical power can compromise plant safety system operability including decay heat removal and emergency core cooling systems which may be necessary to ensure fission product barrier integrity. This category includes loss of vital plant 125 VDC power sources.

3. Loss of Control Room Indications

Certain events that degrade plant operator ability to effectively assess plant conditions within the plant warrant emergency classification. Losses of indicators are in this subcategory.

4. RCS Activity

During normal operation, reactor coolant fission product activity is very low. Small concentrations of fission products in the coolant are primarily from the fission of tramp uranium in the fuel clad or minor perforations in the clad itself. Any significant increase from these base-line levels (2% - 5% clad failures) is indicative of fuel failures and is covered under the Fission Product Barrier Degradation category. However, lesser amounts of clad damage may result in coolant activity exceeding Technical Specification limits. These fission products will be circulated with the reactor coolant and can be detected by coolant sampling.

5. RCS Leakage

The reactor vessel provides a volume for the coolant that covers the reactor core. The reactor pressure vessel and associated pressure piping (reactor coolant system) together provide a barrier to limit the release of radioactive material should the reactor fuel clad integrity fail. Excessive RCS leakage greater than Technical Specification limits indicates potential pipe cracks that may propagate to an extent threatening fuel clad, RCS and containment integrity.

6. RPS Failure

This subcategory includes events related to failure of the Reactor Protection System (RPS) to initiate and complete reactor trips. In the plant licensing basis, postulated failures of the RPS to complete a reactor trip comprise a specific set of analyzed events referred to as Anticipated Transient Without Scram (ATWS) events. For EAL classification, however, ATWS is intended to mean any trip failure event that does not achieve reactor shutdown. If RPS actuation fails to assure reactor shutdown, positive control of reactivity is at risk and could cause a threat to fuel clad, RCS and containment integrity.

7. Loss of Communications

Certain events that degrade plant operator ability to effectively communicate with essential personnel within or external to the plant warrant emergency classification.

8. Containment Failure

Failure of containment isolation capability (under conditions in which the containment is not currently challenged) warrants emergency classification. Failure of containment pressure control capability also warrants emergency classification.

9. Hazardous Event Affecting Safety Systems

Various natural and technological events that result in degraded plant safety system performance or significant visible damage warrant emergency classification under this subcategory.

Category: S – System Malfunction

Subcategory: 1 – Loss of Emergency AC Power

Initiating Condition: Loss of **all** offsite AC power capability to safeguard buses for 15 minutes or longer

EAL:

SU1.1 Unusual Event

Loss of **all** offsite AC power capability, Table S-1, to 6.9 KV safeguard buses uEA1 and uEA2 for greater than or equal to 15 min. (Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table S-1 AC Power Sources
Offsite:
• 138 KV switchyard circuit
• 345 KV switchyard circuit
Onsite:
• uEG1
• uEG2

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 – Hot Shutdown

Definition(s):

None

Basis:

For emergency classification purposes, “capability” means that an offsite AC power source(s) is available to the safeguard buses, whether or not the buses are powered from it.

The safeguards AC distribution system power sources consist of the preferred and alternate offsite power sources, and the onsite standby emergency diesel generators uEG1 and uEG2. Offsite power is supplied to the plant switchyards from the transmission network by five 345 KV and two 138 KV transmission lines. From the switchyards, two electrically and physically separated circuits provide AC power through step down startup transformers, to the 6.9 kV safeguard buses. The 138 kV switchyard circuit is the preferred source for Unit 2 and alternate source for Unit 1. The 345 KV circuit is the preferred source for Unit 1 and alternate source for Unit 2. The onsite AC distribution system is divided into redundant trains so that the loss of any one load group does not prevent the minimum safety functions from being performed. Each train has connections to two offsite power sources and a dedicated diesel generator. Each offsite circuit can supply the Unit 1 and Unit 2 6.9 KV safeguard buses. (ref. 1, 2, 3, 4)

The 15-minute interval was selected as a threshold to exclude transient or momentary power losses.

This IC addresses a prolonged loss of offsite power. The loss of offsite power sources renders the plant more vulnerable to a complete loss of power to AC emergency buses. This condition represents a potential reduction in the level of safety of the plant.

For emergency classification purposes, “capability” means that an offsite AC power source(s) is available to the emergency buses, whether or not the buses are powered from it.

Escalation of the emergency classification level would be via IC SA1.

CPNPP Basis Reference(s):

1. FSAR Figure 8.3-1
2. FSAR Section 8.2
3. FSAR Section 8.3
4. Technical Specifications B3.8.1
5. ABN-601 Response to a 138/345 KV System Malfunction
6. ABN-602 Response to a 6900/480V System Malfunction
7. NEI 99-01 SU1

Category: S – System Malfunction

Subcategory: 1 – Loss of Emergency AC Power

Initiating Condition: Loss of **all but one** AC power source to safeguard buses for 15 minutes or longer

EAL:

SA1.1 Alert

AC power capability, Table S-1, to 6.9 KV safeguard buses uEA1 and uEA2 reduced to a single power source for greater than or equal to 15 min. (Note 1)

AND

Any additional single power source failure will result in loss of **all** AC power to SAFETY SYSTEMS

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table S-1 AC Power Sources
Offsite: • 138 KV switchyard circuit • 345 KV switchyard circuit **Onsite:** • uEG1 • uEG2

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

SAFETY SYSTEM - A system required for safe plant operation, cooling down the plant and/or placing it in the cold shutdown condition, including the ECCS. These are typically systems classified as safety-related (as defined in 10CFR50.2):

Those structures, systems and components that are relied upon to remain functional during and following design basis events to assure:

(1) The integrity of the reactor coolant pressure boundary;

(2) The capability to shut down the reactor and maintain it in a safe shutdown condition;

(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures.

Basis:

For emergency classification purposes, "capability" means that an offsite AC power source(s) is available to the emergency buses, whether or not the buses are powered from it.

The condition indicated by this EAL is the degradation of the offsite and onsite power sources such that any additional single failure would result in a loss of all AC power to the safeguard buses.

The safeguards AC distribution system power sources consist of the preferred and alternate offsite power sources, and the onsite standby emergency diesel generators uEG1 and uEG2. Offsite power is supplied to the plant switchyards from the transmission network by five 345 KV and two 138 KV transmission lines. From the switchyards, two electrically and physically separated circuits provide AC power through step down startup transformers, to the 6.9 kV safeguard buses. The 138 kV switchyard circuit is the preferred source for Unit 2 and alternate source for Unit 1. The 345 KV circuit is the preferred source for Unit 1 and alternate source for Unit 2. The onsite AC distribution system is divided into redundant trains so that the loss of any one load group does not prevent the minimum safety functions from being performed. Each train has connections to two offsite power sources and a dedicated diesel generator. Each offsite circuit can supply the Unit 1 and Unit 2 6.9 KV safeguard buses. (ref. 1, 2, 3, 4).

The 15-minute interval was selected as a threshold to exclude transient or momentary power losses. If the capability of a second source of emergency bus power is not restored within 15 minutes, an Alert is declared under this EAL.

This hot condition EAL is equivalent to the cold condition EAL CU2.1.

This IC describes a significant degradation of offsite and onsite AC power sources such that any additional single failure would result in a loss of all AC power to SAFETY SYSTEMS. In this condition, the sole AC power source may be powering one, or more than one, train of safety-related equipment. This IC provides an escalation path from IC SU1.

An “AC power source” is a source recognized in AOPs and EOPs, and capable of supplying required power to an emergency bus. Some examples of this condition are presented below.

- A loss of all offsite power with a concurrent failure of all but one emergency power source (e.g., an onsite diesel generator).
- A loss of all offsite power and loss of all emergency power sources (e.g., onsite diesel generators) with a single train of emergency buses being back-fed from the unit main generator.
- A loss of emergency power sources (e.g., onsite diesel generators) with a single train of emergency buses being fed from an offsite power source.

Escalation of the emergency classification level would be via IC SS1.

CPNPP Basis Reference(s):

1. FSAR Figure 8.3-1
2. FSAR Section 8.2
3. FSAR Section 8.3
4. Technical Specifications B3.8.1
5. ABN-601 Response to a 138/345 KV System Malfunction
6. ABN-602 Response to a 6900/480V System Malfunction
7. NEI 99-01 SA1

Category: S – System Malfunction

Subcategory: 1 – Loss of Emergency AC Power

Initiating Condition: Loss of **all** offsite power and **all** onsite AC power to safeguard buses for 15 minutes or longer

EAL:

SS1.1 **Site Area Emergency**
Loss of **all** offsite and **all** onsite AC power capability to 6.9 KV safeguard buses uEA1 and uEA2 for greater than or equal to 15 min. (Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

For emergency classification purposes, "capability" means that an AC power source is available to the safeguard buses, whether or not the buses are powered from it.

The safeguards AC distribution system power sources consist of the preferred and alternate offsite power sources, and the onsite standby emergency diesel generators uEG1 and uEG2. Offsite power is supplied to the plant switchyards from the transmission network by five 345 KV and two 138 KV transmission lines. From the switchyards, two electrically and physically separated circuits provide AC power through step down startup transformers, to the 6.9 kV safeguard buses. The 138 kV switchyard circuit is the preferred source for Unit 2 and alternate source for Unit 1. The 345 KV circuit is the preferred source for Unit 1 and alternate source for Unit 2. The onsite AC distribution system is divided into redundant trains so that the loss of any one load group does not prevent the minimum safety functions from being performed. Each train has connections to two offsite power sources and a dedicated diesel generator. Each offsite circuit can supply the Unit 1 and Unit 2 6.9 KV safeguard buses. (ref. 1, 2, 3, 4).

The 15-minute interval was selected as a threshold to exclude transient or momentary power losses. The interval begins when both offsite and onsite AC power capability are lost.

This IC addresses a total loss of AC power that compromises the performance of all SAFETY SYSTEMS requiring electric power including those necessary for emergency core cooling, containment heat removal/pressure control, spent fuel heat removal and the ultimate heat sink. In addition, fission product barrier monitoring capabilities may be degraded under these conditions. This IC represents a condition that involves actual or likely major failures of plant functions needed for the protection of the public.

Escalation of the emergency classification level would be via ICs RG1, FG1 or SG1.

CPNPP Basis Reference(s):

1. FSAR Figure 8.3-1
2. FSAR Section 8.2
3. FSAR Section 8.3
4. Technical Specifications B3.8.1
5. ABN-601 Response to a 138/345 KV System Malfunction
6. ABN-602 Response to a 6900/480V System Malfunction
7. NEI 99-01 SS1

Category: S –System Malfunction

Subcategory: 1 – Loss of Emergency AC Power

Initiating Condition: Prolonged loss of **all** offsite and **all** onsite AC power to safeguard buses

EAL:

SG1.1 General Emergency

Loss of **all** offsite and **all** onsite AC power capability to 6.9 KV safeguard buses uEA1 and uEA2

AND EITHER:

- Restoration of at least one safeguard bus in less than 4 hours is **not** likely (Note 1)
- CSFST Core Cooling RED Path conditions met

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

This EAL is indicated by the extended loss of all offsite and onsite AC power capability to 6.9 KV safeguard buses uEA1 and uEA2 either for greater then the CPNPP Station Blackout (SBO) coping analysis time (4 hrs.) (ref. 7) or that has resulted in indications of an actual loss of adequate core cooling.

Indication of continuing core cooling degradation is manifested by CSFST Core Cooling RED Path conditions being met. (ref. 8).

For emergency classification purposes, “capability” means that an AC power source is available to the emergency buses, whether or not the buses are powered from it.

The safeguards AC distribution system power sources consist of the preferred and alternate offsite power sources, and the onsite standby emergency diesel generators uEG1 and uEG2. Offsite power is supplied to the plant switchyards from the transmission network by five 345 KV and two 138 KV transmission lines. From the switchyards, two electrically and physically separated circuits provide AC power through step down startup transformers, to the 6.9 kV safeguard buses. The 138 kV switchyard circuit is the preferred source for Unit 2 and alternate source for Unit 1. The 345 KV circuit is the preferred source for Unit 1 and alternate source for Unit 2. The onsite AC distribution system is divided into redundant trains so that the loss of any one load group does not prevent the minimum safety functions from being performed. Each train has connections to two offsite power sources and a dedicated diesel generator. Each offsite circuit can supply the Unit 1 and Unit 2 6.9 KV safeguard buses. (ref. 1, 2, 3, 4).

CPNPP has also provided a set of non-safety related Alternate Power Diesel Generators (APDGs) for each unit with the capability to connect to a safeguards bus one at a time to provide defense-in-depth for safe shutdown of a unit during outages or during extended duration of an inoperable offsite circuit on occurrence of concurrent loss of offsite power and failure of EDGs. The APDGs can provide 3450 kVA to provide long term cooling of each unit (ref. 3).

Four hours is the station blackout coping time (ref 7).

Indication of continuing core cooling degradation must be based on fission product barrier monitoring with particular emphasis on Emergency Coordinator judgment as it relates to imminent loss of fission product barriers and degraded ability to monitor fission product barriers. Indication of continuing core cooling degradation is manifested by CSFST Core Cooling RED path conditions being met (ref. 8). Critical Safety Function Status Tree (CSFST) Core Cooling-RED path indicates significant core exit superheating and core uncovery. (ref. 3).

This IC addresses a prolonged loss of all power sources to AC emergency buses. A loss of all AC power compromises the performance of all SAFETY SYSTEMS requiring electric power including those necessary for emergency core cooling, containment heat removal/pressure control, spent fuel heat removal and the ultimate heat sink. A prolonged loss of these buses will lead to a loss of one or more fission product barriers. In addition, fission product barrier monitoring capabilities may be degraded under these conditions.

The EAL should require declaration of a General Emergency prior to meeting the thresholds for IC FG1. This will allow additional time for implementation of offsite protective actions.

Escalation of the emergency classification from Site Area Emergency will occur if it is projected that power cannot be restored to at least one AC emergency bus by the end of the analyzed station blackout coping period. Beyond this time, plant responses and event trajectory are subject to greater uncertainty, and there is an increased likelihood of challenges to multiple fission product barriers.

The estimate for restoring at least one emergency bus should be based on a realistic appraisal of the situation. Mitigation actions with a low probability of success should not be used as a basis for delaying a classification upgrade. The goal is to maximize the time available to prepare for, and implement, protective actions for the public.

The EAL will also require a General Emergency declaration if the loss of AC power results in parameters that indicate an inability to adequately remove decay heat from the core.

CPNPP Basis Reference(s):

1. FSAR Figure 8.3-1
2. FSAR Section 8.2
3. FSAR Section 8.3
4. Technical Specifications B3.8.1
5. ABN-601 Response to a 138/345 KV System Malfunction
6. ABN-602 Response to a 6900/480V System Malfunction
7. FSAR Section 8B Station Blackout
8. FRC-0.1A/B Response to Inadequate Core Cooling
9. NEI 99-01 SG1

Category: S –System Malfunction

Subcategory: 1 – Loss of Emergency AC Power

Initiating Condition: Loss of **all** AC and vital DC power sources for 15 minutes or longer

EAL:

SG1.2 General Emergency
Loss of **all** offsite and **all** onsite AC power capability to 6.9 KV safeguard buses uEA1 and uEA2 for greater than or equal to 15 min.
AND
Less than 105 VDC on **all** 125 VDC safeguard buses uED1, uED2, uED3 and uED4 for greater than or equal to 15 min.
(Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

This EAL is indicated by the loss of all offsite and onsite emergency AC power capability to 6.9 KV safeguard buses uEA1 and uEA2 for greater than 15 minutes in combination with degraded vital DC power voltage. This EAL addresses operating experience from the March 2011 accident at Fukushima Daiichi.

For emergency classification purposes, “capability” means that an AC power source is available to the emergency buses, whether or not the buses are powered from it.

The safeguards AC distribution system power sources consist of the preferred and alternate offsite power sources, and the onsite standby emergency diesel generators uEG1 and uEG2. Offsite power is supplied to the plant switchyards from the transmission network by five 345 KV and two 138 KV transmission lines. From the switchyards, two electrically and physically separated circuits provide AC power through step down startup transformers, to the 6.9 kV safeguard buses. The 138 kV switchyard circuit is the preferred source for Unit 2 and alternate source for Unit 1. The 345 KV circuit is the preferred source for Unit 1 and alternate source for Unit 2. The onsite AC distribution system is divided into redundant trains so that the loss of any one load group does not prevent the minimum safety functions from being performed. Each train has connections to two offsite power sources and a dedicated diesel generator. Each offsite circuit can supply the Unit 1 and Unit 2 6.9 KV safeguard buses. (ref. 1, 2, 3, 4).

The safeguards 125 VDC buses are the Class 1E buses uED1, uED2, uED3 and uED4 (ref. 7, 8, 9).

Each redundant safeguards 125 VDC system consists of two independent batteries each having one main distribution bus, two static battery chargers (one spare), and local distribution panels. For Unit 1, batteries BT1ED1 and BT1ED3 feed all train A load requirements, while batteries BT1ED2 and BT1ED4 supply train B load requirements.

For Unit 2, batteries BT2ED1 and BT2ED3 feed all train A load requirements, while batteries BT2ED2 and BT2ED4 supply train B load requirements. There are no bus ties or sharing of power supplies between redundant trains (ref. 7).

Minimum DC bus voltage is 105 VDC (ref. 10). Bus voltage may be monitored from the following indications (ref. 12):

Control Room Panel CP-10	Annunciator u--ALB-10B	Plant Computer
V-1ED1, 125VDC SWITCH PNL 1ED1 VOLT	1.13	V6501A BATT BT1ED1 VOLT
V-1ED2, 125VDC SWITCH PNL 1ED2 VOLT	2.13	V6502A BATT BT1ED2 VOLT
V-1ED3, 125VDC SWITCH PNL 1ED3 VOLT	1.9	none
V-1ED4, 125VDC SWITCH PNL 1ED4 VOLT	3.9	V6504A BATT BT1ED4 VOLT

This IC addresses a concurrent and prolonged loss of both emergency AC and Vital DC power. A loss of all emergency AC power compromises the performance of all SAFETY SYSTEMS requiring electric power including those necessary for emergency core cooling, containment heat removal/pressure control, spent fuel heat removal and the ultimate heat sink. A loss of vital DC power compromises the ability to monitor and control SAFETY SYSTEMS. A sustained loss of both emergency AC and vital DC power will lead to multiple challenges to fission product barriers.

Fifteen minutes was selected as a threshold to exclude transient or momentary power losses. The 15-minute emergency declaration clock begins at the point when both EAL thresholds are met.

CPNPP Basis Reference(s):

1. FSAR Figure 8.3-1
2. FSAR Section 8.2
3. FSAR Section 8.3
4. Technical Specifications B3.8.1
5. ABN-601 Response to a 138/345 KV System Malfunction
6. ABN-602 Response to a 6900/480V System Malfunction
7. FSAR 8.3.2
8. FSAR Figure 8.3-14
9. FSAR Figure 8.3-14A
10. ECA-0.0A/B Loss of All AC Power
11. SOP-605A/B 125 VDC Switchgear and Distribution Systems, Batteries and Battery Chargers
12. ALM-0102A/B Alarm Procedures Manual, u-ALB-10B, nos. 1.9, 1.13, 2.13, 3.8
13. NEI 99-01 SG8

Category: S – System Malfunction

Subcategory: 2 – Loss of Vital DC Power

Initiating Condition: Loss of **all** vital DC power for 15 minutes or longer

EAL:

SS2.1	**Site Area Emergency**
Less than 105 VDC on **all** 125 VDC safeguard buses uED1, uED2, uED3 and uED4 for greater than or equal to 15 min. (Note 1)	

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

The safeguards 125 VDC buses are the Class 1E buses uED1, uED2, uED3 and uED4 (ref. 1, 2, 3).

Each redundant safeguards 125 VDC system consists of two independent batteries each having one main distribution bus, two static battery chargers (one spare), and local distribution panels. For Unit 1, batteries BT1ED1 and BT1ED3 feed all train A load requirements, while batteries BT1ED2 and BT1ED4 supply train B load requirements.

For Unit 2, batteries BT2ED1 and BT2ED3 feed all train A load requirements, while batteries BT2ED2 and BT2ED4 supply train B load requirements. There are no bus ties or sharing of power supplies between redundant trains (ref. 1).

Minimum DC bus voltage is 105 VDC (ref. 4). Bus voltage may be monitored from the following indications (ref. 6):

Control Room Panel CP-10	Annunciator u--ALB-10B	Plant Computer
V-1ED1, 125VDC SWITCH PNL 1ED1 VOLT	1.13	V6501A BATT BT1ED1 VOLT
V-1ED2, 125VDC SWITCH PNL 1ED2 VOLT	2.13	V6502A BATT BT1ED2 VOLT
V-1ED3, 125VDC SWITCH PNL 1ED3 VOLT	1.9	V6503A BATT BT1ED3 VOLT
V-1ED4, 125VDC SWITCH PNL 1ED4 VOLT	3.9	V6504A BATT BT1ED4 VOLT

This IC addresses a loss of vital DC power which compromises the ability to monitor and control SAFETY SYSTEMS. In modes above Cold Shutdown, this condition involves a major failure of plant functions needed for the protection of the public.

Fifteen minutes was selected as a threshold to exclude transient or momentary power losses.

Escalation of the emergency classification level would be via ICs RG1, FG1 or SG1.

CPNPP Basis Reference(s):

1. FSAR 8.3.2
2. FSAR Figure 8.3-14
3. FSAR Figure 8.3-14A
4. ECA-0.0A/B Loss of All AC Power
5. SOP-605A/B 125 VDC Switchgear and Distribution Systems, Batteries and Battery Chargers
6. ALM-0102A/B Alarm Procedures Manual, u-ALB-10B, nos. 1.9, 1.13, 2.13, 3.8
7. NEI 99-01 SS8

Category: S – System Malfunction

Subcategory: 3 – Loss of Control Room Indications

Initiating Condition: UNPLANNED loss of Control Room indications for 15 minutes or longer

EAL:

SU3.1 Unusual Event
An UNPLANNED event results in the inability to monitor one or more Table S-2 parameters from within the Control Room for greater than or equal to 15 min. (Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table S-2 Safety System Parameters
• Reactor power • RCS level • RCS pressure • Core Exit T/C temperature • Level in at least one SG • Auxiliary or emergency feed flow in at least one SG

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

UNPLANNED - A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

SAFETY SYSTEM parameters listed in Table S-2 are monitored in the Control Room through a combination of hard control panel indicators as well as computer based information systems. The Plant Process Computer, which displays SPDS required information, serves as a redundant compensatory indicator which may be utilized in lieu of normal Control Room indicators (ref. 1, 2, 3, 4).

This IC addresses the difficulty associated with monitoring normal plant conditions without the ability to obtain SAFETY SYSTEM parameters from within the Control Room. This condition is a precursor to a more significant event and represents a potential degradation in the level of safety of the plant.

As used in this EAL, an "inability to monitor" means that values for one or more of the listed parameters cannot be determined from within the Control Room. This situation would require a loss of all of the Control Room sources for the given parameter(s). For example, the reactor power level cannot be determined from any analog, digital and recorder source within the Control Room.

An event involving a loss of plant indications, annunciators and/or display systems is evaluated in accordance with 10 CFR 50.72 (and associated guidance in NUREG-1022) to determine if an NRC event report is required. The event would be reported if it significantly impaired the capability to perform emergency assessments. In particular, emergency assessments necessary to implement abnormal operating procedures, emergency operating procedures, and emergency plan implementing procedures addressing emergency classification, accident assessment, or protective action decision-making.

This EAL is focused on a selected subset of plant parameters associated with the key safety functions of reactivity control, core cooling and RCS heat removal. The loss of the ability to determine one or more of these parameters from within the Control Room is considered to be more significant than simply a reportable condition. In addition, if all indication sources for one or more of the listed parameters are lost, then the ability to determine the values of other SAFETY SYSTEM parameters may be impacted as well. For example, if the value for reactor vessel level cannot be determined from the indications and recorders on a main control board, the SPDS or the plant computer, the availability of other parameter values may be compromised as well.

Fifteen minutes was selected as a threshold to exclude transient or momentary losses of indication.

Escalation of the emergency classification level would be via IC SA3.

CPNPP Basis Reference(s):

1. FSAR Section 7.5
2. DBD-EE-033 Detailed Control Room Design, 5.1.2, Figure 1
3. SOP 906 Plant Process Computer System Guidelines
4. ABN 906 Plant Process Computer System Malfunction
5. NEI 99-01 SU2

Category: S – System Malfunction

Subcategory: 3 – Loss of Control Room Indications

Initiating Condition: UNPLANNED loss of Control Room indications for 15 minutes or longer with a significant transient in progress

EAL:

SA3.1 Alert

An UNPLANNED event results in the inability to monitor one or more Table S-2 parameters from within the Control Room for greater than or equal to 15 min. (Note 1)

AND

Any significant transient is in progress, Table S-3

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Table S-2 Safety System Parameters
• Reactor power • RCS level • RCS pressure • Core Exit T/C temperature • Level in at least one SG • Auxiliary or emergency feed flow in at least one SG

Table S-3 Significant Transients
• Reactor trip • Runback greater than or equal to 25% thermal power • Electrical load rejection greater than 25% electrical load • ECCS actuation

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

UNPLANNED - A parameter change or an event that is not 1) the result of an intended evolution or 2) an expected plant response to a transient. The cause of the parameter change or event may be known or unknown.

Basis:

SAFETY SYSTEM parameters listed in Table S-1 are monitored in the Control Room through a combination of hard control panel indicators as well as computer based information systems. The Plant Computer, which displays SPDS required information, serves as a redundant compensatory indicator which may be utilized in lieu of normal Control Room indicators (ref. 1, 2, 3, 4).

Significant transients are listed in Table S-2 and include response to automatic or manually initiated functions such as reactor trips, runbacks involving greater than or equal to 25% thermal power change, electrical load rejections of greater than 25% full electrical load or ECCS (SI) injection actuations.

This IC addresses the difficulty associated with monitoring rapidly changing plant conditions during a transient without the ability to obtain SAFETY SYSTEM parameters from within the Control Room. During this condition, the margin to a potential fission product barrier challenge is reduced. It thus represents a potential substantial degradation in the level of safety of the plant.

As used in this EAL, an “inability to monitor” means that values for one or more of the listed parameters cannot be determined from within the Control Room. This situation would require a loss of all of the Control Room sources for the given parameter(s). For example, the reactor power level cannot be determined from any analog, digital and recorder source within the Control Room.

An event involving a loss of plant indications, annunciators and/or display systems is evaluated in accordance with 10 CFR 50.72 (and associated guidance in NUREG-1022) to determine if an NRC event report is required. The event would be reported if it significantly impaired the capability to perform emergency assessments. In particular, emergency assessments necessary to implement abnormal operating procedures, emergency operating procedures, and emergency plan implementing procedures addressing emergency classification, accident assessment, or protective action decision-making.

This EAL is focused on a selected subset of plant parameters associated with the key safety functions of reactivity control, core cooling and RCS heat removal. The loss of the ability to determine one or more of these parameters from within the Control Room is considered to be more significant than simply a reportable condition. In addition, if all indication sources for one or more of the listed parameters are lost, then the ability to determine the values of other SAFETY SYSTEM parameters may be impacted as well. For example, if the value for reactor vessel level cannot be determined from the indications and recorders on a main control board, the SPDS or the plant computer, the availability of other parameter values may be compromised as well.

Fifteen minutes was selected as a threshold to exclude transient or momentary losses of indication.

Escalation of the emergency classification level would be via ICs FS1 or IC RS1

CPNPP Basis Reference(s):

1. FSAR Section 7.5
2. DBD-EE-033 Detailed Control Room Design, 5.1.2, Figure 1
3. SOP 906 Plant Process Computer System Guidelines
4. ABN 906 Plant Process Computer System Malfunction
5. NEI 99-01 SA2

Category: S – System Malfunction

Subcategory: 4 – RCS Activity

Initiating Condition: Reactor coolant activity greater than Technical Specification allowable limits

EAL:

SU4.1 Unusual Event

Reactor coolant Dose Equivalent I-131 specific activity greater than 60 μCi/gm

OR

Reactor coolant Dose Equivalent XE-133 specific activity greater than 500 μCi/gm

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

This EAL addresses reactor coolant samples exceeding Technical Specification LCOs 3.4.16.A and 3.4.16.B which are applicable in Modes 1, 2, and 3 and 4 (ref. 1). The Technical Specification limits accommodate an iodine spike phenomenon that may occur following changes in thermal power. The Technical Specification LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) accident (ref. 2).

This IC addresses a reactor coolant activity value that exceeds an allowable limit specified in Technical Specifications. This condition is a precursor to a more significant event and represents a potential degradation of the level of safety of the plant.

Escalation of the emergency classification level would be via ICs FA1 or the Recognition Category R ICs.

CPNPP Basis Reference(s):

1. Technical Specifications Section 3.4.16
2. Technical Specifications Section B3.4.16
3. NEI 99-01 SU3

Category: S – System Malfunction

Subcategory: 4 – RCS Activity

Initiating Condition: Reactor coolant activity greater than Technical Specification allowable limits

EAL:

SU4.2 Unusual Event

Gross Failed Fuel Monitor, FFLu60 (u-RE-0406), High Alarm (RED)

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

This EAL addresses reactor coolant letdown line radiation levels sensed by FFLu60 (u-RE-0406) in excess of Technical Specification allowable limits. The High Alarm (RED) setpoint is based on the Technical Specifications maximum allowable concentration of radioactivity in the reactor coolant (ref. 1, 2, 3). A Geiger-Mueller tube is mounted on the reactor coolant letdown line after the letdown heat exchanger to monitor fission-product activity. Detection of increased system activity may be indicative of failed fuel. The monitor initiates Alert and High alarms in the Control Room (PC-11 and Plant Computer) (ref. 3, 4, 5, 6, 7, 8).

FFLu60 (u-RE-0406) has a range of 1E-2 – 1E+7 µCi/ml.

This IC addresses a reactor coolant activity value that exceeds an allowable limit specified in Technical Specifications. This condition is a precursor to a more significant event and represents a potential degradation of the level of safety of the plant.

Escalation of the emergency classification level would be via ICs FA1 or the Recognition Category R ICs.

CPNPP Basis Reference(s):

1. Technical Specifications Section 3.4.16
2. ALM-3200 Alarm Procedure DRMS, Channel in High Alarm (RED), pg 54
3. DBD-EE-023 Radiation Monitoring System
4. SWEC-NU(S)-174 Radiation Monitor Alarm Concentrations for Failed Fuel Monitors 1-RE-406 & 2-RE-406
5. ABN-102 High Coolant Activity
6. FSAR Section 11.5.2.7.11
7. FSAR Table 11.5-1
8. CHM-111 Primary Chemistry Accident Assessment Sampling Program
9. DBD-EE-023 Radiation Monitoring System
10. NEI 99-01 SU3

Category: S – System Malfunction

Subcategory: 5 – RCS Leakage

Initiating Condition: RCS leakage for 15 minutes or longer

EAL:

SU5.1 Unusual Event

RCS unidentified or pressure boundary leakage greater than 10 gpm for greater than or equal to 15 min.

OR

RCS identified leakage greater than 25 gpm for greater than or equal to 15 min.

OR

UNISOLABLE leakage from the RCS to a location outside containment greater than 25 gpm for greater than or equal to 15 min.

(Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

RCS leakage outside of the containment that is not considered identified or unidentified leakage per Technical Specifications includes leakage via interfacing systems such as RCS to the Component Cooling Water, or systems that directly see RCS pressure outside containment such as Chemical & Volume Control System, Nuclear Sampling system and Residual Heat Removal system (when in the shutdown cooling mode) (ref. 3, 6, 8)

Isolating letdown is a standard abnormal operating procedure action and may prevent unnecessary classification when a non-RCS leakage path, such as a CVCS leak, exists.

Unidentified leakage and identified leakage are determined by performance of the RCS water inventory balance. Pressure boundary leakage would first appear as unidentified leakage and can only be positively identified by inspection (ref. 1). OPT-303 (ref. 1) is used to ensure RCS leakage is within Technical Specification limits (ref. 2). ABN-103 Attachments 1 and 3 (ref. 3) are used for excessive RCS leakage.

Technical Specifications (ref. 4) defines RCS leakage as follows:

- Identified Leakage:
  - Leakage such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank

- Leakage into the Containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary leakage.
- Reactor Coolant System leakage through a steam generator to the Secondary System (primary to secondary leakage);

- Unidentified Leakage: All leakage (except RCP seal water injection or leakoff) that is not identified leakage.
- Pressure Boundary Leakage: Leakage (except primary to secondary leakage) through a non-isolable fault in an RCS component body, pipe wall, or vessel wall.

Escalation of this EAL to the Alert level is via Category F, Fission Product Barrier Degradation, EAL FA1.1.

This IC addresses RCS leakage which may be a precursor to a more significant event. In this case, RCS leakage has been detected and operators, following applicable procedures, have been unable to promptly isolate the leak. This condition is considered to be a potential degradation of the level of safety of the plant.

The first and second EAL conditions are focused on a loss of mass from the RCS due to “unidentified leakage", "pressure boundary leakage" or "identified leakage” (as these leakage types are defined in the plant Technical Specifications). The third condition addresses an RCS mass loss caused by an UNISOLABLE leak through an interfacing system. These conditions thus apply to leakage into the containment, a secondary-side system (e.g., steam generator tube leakage) or a location outside of containment.

The leak rate values for each condition were selected because they are usually observable with normal Control Room indications. Lesser values typically require time-consuming calculations to determine (e.g., a mass balance calculation). The first condition uses a lower value that reflects the greater significance of unidentified or pressure boundary leakage.

The release of mass from the RCS due to the as-designed/expected operation of a relief valve does not warrant an emergency classification. An emergency classification would be required if a mass loss is caused by a relief valve that is not functioning as designed/expected (e.g., a relief valve sticks open and the line flow cannot be isolated).

The 15-minute threshold duration allows sufficient time for prompt operator actions to isolate the leakage, if possible.

CPNPP Basis Reference(s):

1. OPT-303 Reactor Coolant System Water Inventory
2. Technical Specifications 3.4.13
3. ABN-103 Excessive Reactor Coolant Leakage
4. Technical Specifications 1.1
5. ABN-108 Shutdown Loss of Coolant
6. FSAR 5.2.5.2
7. FSAR 5.2.5.8
8. ECA-1.2 LOCA Outside Containment
9. NEI 99-01 SU4

Category: S – System Malfunction

Subcategory: 6 – RPS Failure

Initiating Condition: Automatic or manual trip fails to shut down the reactor

EAL:

SU6.1 Unusual Event
An automatic trip did **not** shut down the reactor as indicated by reactor power greater than 5% after **any** RPS setpoint is exceeded **AND** A subsequent automatic trip or manual trip action taken at the reactor control consoles (MCB reactor trip switches or deenergizing uB3 and uB4) is successful in shutting down the reactor as indicated by reactor power less than or equal to 5% (Note 8)

Note 8: A manual trip action is any operator action, or set of actions, which causes the control rods to be rapidly inserted into the core, and **does not** include manually driving in control rods or implementation of boron injection strategies.

Mode Applicability:

1 - Power Operation

Definition(s):

None

Basis:

The first condition of this EAL identifies the need to cease critical reactor operations by actuation of the automatic Reactor Protection System (RPS) trip function. A reactor trip is automatically initiated by the RPS when certain continuously monitored parameters exceed predetermined setpoints (ref. 1).

Following a successful reactor trip, rapid insertion of the control rods occurs. Nuclear power promptly drops to a fraction of the original power level and then decays to a level several decades less with a negative startup rate. The reactor power drop continues until reactor power reaches the point at which the influence of source neutrons on reactor power starts to be observable. A predictable post-trip response from an automatic reactor trip signal should therefore consist of a prompt drop in reactor power as sensed by the nuclear instrumentation and a lowering of power into the source range. A successful trip has therefore occurred when there is sufficient rod insertion from the trip of RPS to bring the reactor power below the immediate shutdown decay heat level of 5% (ref. 1, 2).

For the purposes of emergency classification, successful manual trip actions are those which can be quickly performed from the reactor control console; MCB reactor trip switches or deenergizing uB3 and uB4. Reactor shutdown achieved by use of other trip actions specified in FR-S.1 Response to Nuclear Power Generation/ATWS (such as manually insert control rods, opening the reactor trip and bypass breakers in the reactor switchgear, tripping the Rod Drive MG sets in the normal switchgear or emergency boration) do not constitute a successful manual trip (ref. 2).

Following any automatic RPS trip signal, E-0.0 (ref. 1) and /FR-S.1 (ref. 2) prescribe insertion of redundant manual trip signals to back up the automatic RPS trip function and ensure reactor shutdown is achieved. Even if the first subsequent manual trip signal inserts all control rods to the full-in position immediately after the initial failure of the automatic trip, the lowest level of classification that must be declared is an Unusual Event (ref. 2).

In the event that the operator identifies a reactor trip is imminent and initiates a successful manual reactor trip before the automatic RPS trip setpoint is reached, no declaration is required. The successful manual trip of the reactor before it reaches its automatic trip setpoint or reactor trip signals caused by instrumentation channel failures do not lead to a potential fission product barrier loss. However, if subsequent manual reactor trip actions fail to reduce reactor power to or below 5%, the event escalates to the Alert under EAL SA6.1.

If by procedure, operator actions include the initiation of an immediate manual trip following receipt of an automatic trip signal and there are no clear indications that the automatic trip failed (such as a time delay following indications that a trip setpoint was exceeded), it may be difficult to determine if the reactor was shut down because of automatic trip or manual actions. If a subsequent review of the trip actuation indications reveals that the automatic trip did not cause the reactor to be shut down, then consideration should be given to evaluating the fuel for potential damage, and the reporting requirements of 50.72 should be considered for the transient event.

This IC addresses a failure of the RPS to initiate or complete an automatic or manual reactor trip that results in a reactor shutdown, and either a subsequent operator manual action taken at the reactor control consoles or an automatic trip is successful in shutting down the reactor. This event is a precursor to a more significant condition and thus represents a potential degradation of the level of safety of the plant.

Following the failure on an automatic reactor trip, operators will promptly initiate manual actions at the reactor control consoles to shutdown the reactor (e.g., initiate a manual reactor trip). If these manual actions are successful in shutting down the reactor, core heat generation will quickly fall to a level within the capabilities of the plant's decay heat removal systems.

If an initial manual reactor trip is unsuccessful, operators will promptly take manual action at another location(s) on the reactor control consoles to shutdown the reactor (e.g., initiate a manual reactor trip) using a different switch). Depending upon several factors, the initial or subsequent effort to manually trip the reactor, or a concurrent plant condition, may lead to the generation of an automatic reactor trip signal. If a subsequent manual or automatic trip is successful in shutting down the reactor, core heat generation will quickly fall to a level within the capabilities of the plant's decay heat removal systems.

A manual action at the reactor control consoles is any operator action, or set of actions, which causes the control rods to be rapidly inserted into the core (e.g., initiating a manual reactor trip). This action does not include manually driving in control rods or implementation of boron injection strategies. Actions taken at back-panels or other locations within the Control Room, or any location outside the Control Room, are not considered to be "at the reactor control consoles".

The plant response to the failure of an automatic or manual reactor trip will vary based upon several factors including the reactor power level prior to the event, availability of the condenser, performance of mitigation equipment and actions, other concurrent plant conditions, etc. If subsequent operator manual actions taken at the reactor control consoles are also unsuccessful in shutting down the reactor, then the emergency classification level will escalate to an Alert via IC SA6. Depending upon the plant response, escalation is also possible via IC FA1. Absent the plant conditions needed to meet either IC SA6 or FA1, an Unusual Event declaration is appropriate for this event.

A reactor shutdown is determined in accordance with applicable Emergency Operating Procedure criteria.

Should a reactor trip signal be generated as a result of plant work (e.g., RPS setpoint testing), the following classification guidance should be applied.

- If the signal causes a plant transient that should have included an automatic reactor trip and the RPS fails to automatically shutdown the reactor, then this IC and the EALs are applicable, and should be evaluated.
- If the signal does not cause a plant transient and the trip failure is determined through other means (e.g., assessment of test results), then this IC and the EALs are not applicable and no classification is warranted.

CPNPP Basis Reference(s):

1. EOP-0.0A/B Reactor Trip or Safety Injection
2. FR-S.1 Response to Nuclear Power Generation/ATWS
3 NEI 99-01 SU5

Category: S – System Malfunction

Subcategory: 6 – RPS Failure

Initiating Condition: Automatic or manual trip fails to shut down the reactor

EAL:

SU6.2 Unusual Event

A manual trip did **not** shut down the reactor as indicated by reactor power greater than 5% after **any** manual trip action was initiated

AND

A subsequent automatic trip or manual trip action taken at the reactor control console (MCB reactor trip switches or deenergizing uB3 and uB4) is successful in shutting down the reactor as indicated by reactor power less than or equal to 5% (Note 8)

Note 8: A manual trip action is any operator action, or set of actions, which causes the control rods to be rapidly inserted into the core, and **does not** include manually driving in control rods or implementation of boron injection strategies.

Mode Applicability:

1 - Power Operation

Definition(s):

None

Basis:

This EAL addresses a failure of a manually initiated trip in the absence of having exceeded an automatic RTS trip setpoint and a subsequent automatic or manual trip is successful in shutting down the reactor (reactor power less than or equal to 5%). (ref. 1).

Following a successful reactor trip, rapid insertion of the control rods occurs. Nuclear power promptly drops to a fraction of the original power level and then decays to a level several decades less with a negative startup rate. The reactor power drop continues until reactor power reaches the point at which the influence of source neutrons on reactor power starts to be observable. A predictable post-trip response from an automatic reactor trip signal should therefore consist of a prompt drop in reactor power as sensed by the nuclear instrumentation and a lowering of power into the source range. A successful trip has therefore occurred when there is sufficient rod insertion from the trip of RPS to bring the reactor power below the immediate shutdown decay heat level of 5% (ref. 1, 2).

For the purposes of emergency classification, successful manual trip actions are those which can be quickly performed from the reactor control console; MCB reactor trip switches or deenergizing uB3 and uB4. Reactor shutdown achieved by use of other trip actions specified in FR-S.1 Response to Nuclear Power Generation/ATWS (such as manually insert control rods, opening the reactor trip and bypass breakers in the reactor switchgear, tripping the Rod Drive MG sets in the normal switchgear or emergency boration) do not constitute a successful manual trip (ref. 2).

Following the failure of any manual trip signal, E-0.0 (ref. 1) and FR-S.1 (ref. 2) prescribe insertion of redundant manual trip signals to back up the RPS trip function and ensure reactor shutdown is achieved. Even if a subsequent automatic trip signal or the first subsequent manual trip signal inserts all control rods to the full-in position immediately after the initial failure of the manual trip, the lowest level of classification that must be declared is an Unusual Event (ref. 2).

If both subsequent automatic and subsequent manual reactor trip actions in the Control Room fail to reduce reactor power below the power associated with the safety system design (less than or equal to 5%) following a failure of an initial manual trip, the event escalates to an Alert under EAL SA6.1.

This IC addresses a failure of the RPS to initiate or complete an automatic or manual reactor trip that results in a reactor shutdown, and either a subsequent operator manual action taken at the reactor control consoles or an automatic trip is successful in shutting down the reactor. This event is a precursor to a more significant condition and thus represents a potential degradation of the level of safety of the plant.

Following the failure on an automatic reactor trip, operators will promptly initiate manual actions at the reactor control consoles to shutdown the reactor (e.g., initiate a manual reactor trip). If these manual actions are successful in shutting down the reactor, core heat generation will quickly fall to a level within the capabilities of the plant’s decay heat removal systems.

If an initial manual reactor trip is unsuccessful, operators will promptly take manual action at another location(s) on the reactor control consoles to shutdown the reactor (e.g., initiate a manual reactor trip) using a different switch. Depending upon several factors, the initial or subsequent effort to manually trip the reactor, or a concurrent plant condition, may lead to the generation of an automatic reactor trip signal. If a subsequent manual or automatic trip is successful in shutting down the reactor, core heat generation will quickly fall to a level within the capabilities of the plant’s decay heat removal systems.

A manual action at the reactor control consoles is any operator action, or set of actions, which causes the control rods to be rapidly inserted into the core (e.g., initiating a manual reactor trip). This action does not include manually driving in control rods or implementation of boron injection strategies. Actions taken at back-panels or other locations within the Control Room, or any location outside the Control Room, are not considered to be “at the reactor control consoles”.

The plant response to the failure of an automatic or manual reactor trip will vary based upon several factors including the reactor power level prior to the event, availability of the condenser, performance of mitigation equipment and actions, other concurrent plant conditions, etc. If subsequent operator manual actions taken at the reactor control consoles are also unsuccessful in shutting down the reactor, then the emergency classification level will escalate to an Alert via IC SA6. Depending upon the plant response, escalation is also possible via IC FA1. Absent the plant conditions needed to meet either IC SA6 or FA1, an Unusual Event declaration is appropriate for this event.

A reactor shutdown is determined in accordance with applicable Emergency Operating Procedure criteria.

Should a reactor trip signal be generated as a result of plant work (e.g., RPS setpoint testing), the following classification guidance should be applied.

- If the signal causes a plant transient that should have included an automatic reactor trip and the RPS fails to automatically shutdown the reactor, then this IC and the EALs are applicable, and should be evaluated.
- If the signal does not cause a plant transient and the trip failure is determined through other means (e.g., assessment of test results), then this IC and the EALs are not applicable and no classification is warranted.

CPNPP Basis Reference(s):

1. EOP-0.0A/B Reactor Trip or Safety Injection
2. FR-S.1 Response to Nuclear Power Generation/ATWS
3. NEI 99-01 SU5

Category: S – System Malfunction

Subcategory: 2 – RPS Failure

Initiating Condition: Automatic or manual trip fails to shut down the reactor and subsequent manual actions taken at the reactor control consoles are not successful in shutting down the reactor

EAL:

SA6.1 Alert

An automatic or manual trip fails to shut down the reactor as indicated by reactor power greater than 5%

AND

Manual trip actions taken at the reactor control console (MCB reactor trip switches or deenergizing uB3 and uB4) are **not** successful in shutting down the reactor as indicated by reactor power greater than 5% (Note 8)

Note 8: A manual trip action is any operator action, or set of actions, which causes the control rods to be rapidly inserted into the core, and **does not** include manually driving in control rods or implementation of boron injection strategies.

Mode Applicability:

1 - Power Operation

Definition(s):

None

Basis:

This EAL addresses any automatic or manual reactor trip signal that fails to shut down the reactor (reactor power less than or equal to 5%) followed by a subsequent manual trip that fails to shut down the reactor to an extent the reactor is producing energy in excess of the heat load for which the safety systems were designed (ref. 1).

For the purposes of emergency classification, successful manual trip actions are those which can be quickly performed from the reactor control console; MCB reactor trip switches or deenergizing uB3 and uB4. Reactor shutdown achieved by use of other trip actions specified in FR-S.1 Response to Nuclear Power Generation/ATWS (such as manually insert control rods, opening the reactor trip and bypass breakers in the reactor switchgear, tripping the Rod Drive MG sets in the normal switchgear or emergency boration) do not constitute a successful manual trip (ref. 2).

5% rated power is a minimum reading on the power range scale that indicates continued power production. It also approximates the decay heat which the shutdown systems were designed to remove and is indicative of a condition requiring immediate response to prevent subsequent core damage. Below 5%, plant response will be similar to that observed during a normal shutdown. Nuclear instrumentation can be used to determine if reactor power is greater than 5 % power (ref. 1, 2).

Escalation of this event to a Site Area Emergency would be under EAL SS6.1 or Emergency Coordinator judgment.

This IC addresses a failure of the RPS to initiate or complete an automatic or manual reactor trip that results in a reactor shutdown, and subsequent operator manual actions taken at the reactor control consoles to shutdown the reactor are also unsuccessful. This condition represents an actual or potential substantial degradation of the level of safety of the plant. An emergency declaration is required even if the reactor is subsequently shutdown by an action taken away from the reactor control consoles since this event entails a significant failure of the RPS.

A manual action at the reactor control console is any operator action, or set of actions, which causes the control rods to be rapidly inserted into the core (e.g., initiating a manual reactor trip). This action does not include manually driving in control rods or implementation of boron injection strategies. If this action(s) is unsuccessful, operators would immediately pursue additional manual actions at locations away from the reactor control console (e.g., locally opening breakers). Actions taken at backpanels or other locations within the Control Room, or any location outside the Control Room, are not considered to be “at the reactor control console”.

The plant response to the failure of an automatic or manual reactor trip will vary based upon several factors including the reactor power level prior to the event, availability of the condenser, performance of mitigation equipment and actions, other concurrent plant conditions, etc. If the failure to shut down the reactor is prolonged enough to cause a challenge to the core cooling or RCS heat removal safety functions, the emergency classification level will escalate to a Site Area Emergency via IC SS6. Depending upon plant responses and symptoms, escalation is also possible via IC FS1. Absent the plant conditions needed to meet either IC SS6 or FS1, an Alert declaration is appropriate for this event.

It is recognized that plant responses or symptoms may also require an Alert declaration in accordance with the Recognition Category F ICs; however, this IC and EAL are included to ensure a timely emergency declaration.

A reactor shutdown is determined in accordance with applicable Emergency Operating Procedure criteria.

CPNPP Basis Reference(s):

1. EOP-0.0A/B Reactor Trip or Safety Injection
2. FR-S.1 Response to Nuclear Power Generation/ATWS
3. NEI 99-01 SA5

Category: S – System Malfunction

Subcategory: 2 – RPS Failure

Initiating Condition: Inability to shut down the reactor causing a challenge to core cooling or RCS heat removal

EAL:

SS6.1 Site Area Emergency

An automatic or manual trip fails to shut down the reactor as indicated by reactor power greater than 5%

AND

All actions to shut down the reactor are **not** successful as indicated by reactor power greater than 5%

AND EITHER:

- CSFST Core Cooling RED Path conditions met
- CSFST Heat Sink RED Path conditions met

Mode Applicability:

1 - Power Operation

Definition(s):

None

Basis:

This EAL addresses the following:

- Any automatic reactor trip signal followed by a manual trip that fails to shut down the reactor to an extent the reactor is producing energy in excess of the heat load for which the safety systems were designed (EAL SA6.1), and
- Indications that either core cooling is extremely challenged or heat removal is extremely challenged.

The combination of failure of both front line and backup protection systems to function in response to a plant transient, along with the continued production of heat, poses a direct threat to the Fuel Clad and RCS barriers.

Reactor shutdown achieved by use of FR-S.1 Response to Nuclear Power Generation/ATWS (such as manually insert control rods, opening the reactor trip and bypass breakers in the reactor switchgear, tripping the Rod Drive MG sets in the normal switchgear or emergency boration) are also credited as a successful manual trip provided reactor power can be reduced below 5% before indications of an extreme challenge to either core cooling or heat removal exist (ref. 1, 2).

5% rated power is a minimum reading on the power range scale that indicates continued power production. It also approximates the decay heat which the shutdown systems were designed to remove and is indicative of a condition requiring immediate response to prevent subsequent core damage. Below 5%, plant response will be similar to that observed during a normal shutdown. Nuclear instrumentation can be used to determine if reactor power is greater than 5% power (ref. 1, 2).

Indication of continuing core cooling degradation is manifested by CSFST Core Cooling RED Path conditions being met. Specifically, Core Cooling RED Path conditions exist if either core exit T/Cs are reading greater than or equal to 1200ºF (ref. 3).

Indication of inability to adequately remove heat from the RCS is manifested by CSFST Heat Sink RED Path conditions being met. Specifically, Heat Sink RED Path conditions exist if narrow range level in at least one steam generator is not greater than or equal to (43[50]% ACC) on Unit 1 or (10 [18]% ACC) on Unit 2 and total feedwater flow to the steam generators is less than or equal to 460 gpm (ref. 4).

This IC addresses a failure of the RPS to initiate or complete an automatic or manual reactor trip that results in a reactor shutdown, all subsequent operator actions to manually shutdown the reactor are unsuccessful, and continued power generation is challenging the capability to adequately remove heat from the core and/or the RCS. This condition will lead to fuel damage if additional mitigation actions are unsuccessful and thus warrants the declaration of a Site Area Emergency.

In some instances, the emergency classification resulting from this IC/EAL may be higher than that resulting from an assessment of the plant responses and symptoms against the Recognition Category F ICs/EALs. This is appropriate in that the Recognition Category F ICs/EALs do not address the additional threat posed by a failure to shut down the reactor. The inclusion of this IC and EAL ensures the timely declaration of a Site Area Emergency in response to prolonged failure to shutdown the reactor.

A reactor shutdown is determined in accordance with applicable Emergency Operating Procedure criteria.

Escalation of the emergency classification level would be via IC RG1 or FG1.

CPNPP Basis Reference(s):

1. EOP-0.0A/B Reactor Trip or Safety Injection
2. FR-S.1 Response to Nuclear Power Generation/ATWS
3. FR-C.1 Response to Inadequate Core Cooling
4. FR-H.1 Response to Loss of Heat Sink
5. NEI 99-01 SS5

Category: S – System Malfunction

Subcategory: 7 – Loss of Communications

Initiating Condition: Loss of **all** onsite or offsite communications capabilities

EAL:

SU7.1 Unusual Event

Loss of **all** Table S-4 onsite communication methods

OR

Loss of **all** Table S-4 offsite communication methods

OR

Loss of **all** Table S-4 NRC communication methods

Table S-4 Communication Methods			
System	**Onsite**	**Offsite**	**NRC**
Gai-tronics Page/Party (PA)	X		
Plant Radios	X		
PABX	X	X	X
Public Telephone	X	X	X
Federal Telephone System (FTS)		X	X

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

Onsite/offsite communications include one or more of the systems listed in Table S-4 (ref. 1, 2).

This EAL is the hot condition equivalent of the cold condition EAL CU5.1.

This IC addresses a significant loss of on-site or offsite communications capabilities. While not a direct challenge to plant or personnel safety, this event warrants prompt notifications to OROs and the NRC.

This IC should be assessed only when extraordinary means are being utilized to make communications possible (e.g., use of non-plant, privately owned equipment, relaying of on-site information via individuals or multiple radio transmission points, individuals being sent to offsite locations, etc.).

The first EAL condition addresses a total loss of the communications methods used in support of routine plant operations.

The second EAL condition addresses a total loss of the communications methods used to notify all OROs of an emergency declaration. The offsite (OROs) referred to here are the State Department of Public Safety, Somervell and Hood County EOCs

The third EAL addresses a total loss of the communications methods used to notify the NRC of an emergency declaration.

CPNPP Basis Reference(s):

1. FSAR 9.5.2
2. DBD-EE-048 Communication System
3. NEI 99-01 SU6

Category: S – System Malfunction

Subcategory: 8 – Containment Failure

Initiating Condition: Failure to isolate containment or loss of containment pressure control.

EAL:

SU8.1 Unusual Event

Any penetration is not isolated within 15 min. of a VALID containment isolation signal

OR

Containment pressure greater than 18 psig with **neither** Containment Spray system operating per design for greater than or equal to 15 min.

(Note 1)

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

VALID - An indication, report, or condition, is considered to be valid when it is verified by (1) an instrument channel check, or (2) indications on related or redundant indicators, or (3) by direct observation by plant personnel, such that doubt related to the indicator's operability, the condition's existence, or the report's accuracy is removed. Implicit in this definition is the need for timely assessment.

Basis:

The Containment Spray System (CSS) is designed to remove heat from the Containment environment following a LOCA, a main steam line break accident, or a feedwater line break accident. Each unit of the CPNPP is equipped with two redundant Containment spray trains, each designed to provide emergency Containment heat removal in the event of a LOCA. This system, in conjunction with the ECCS, removes post-accident thermal energy from the Containment environment, thereby reducing the Containment pressure and temperature. Each train includes two containment spray pumps, spray headers, nozzles, valves, and piping. Each train is powered from a separate safeguard bus. (ref. 1)

The Containment pressure setpoint (18 psig, ref. 2) is the pressure at which the Containment Spray System should actuate and begin performing its function. The design basis accident analyses and evaluations assume the loss of one Containment Spray System train (ref. 1).

This EAL addresses a failure of one or more containment penetrations to automatically isolate (close) when required by an actuation signal. It also addresses an event that results in high containment pressure with a concurrent failure of containment pressure control systems. Absent challenges to another fission product barrier, either condition represents potential degradation of the level of safety of the plant.

For the first condition, the containment isolation signal must be generated as the result on an off-normal/accident condition (e.g., a safety injection or high containment pressure); a failure resulting from testing or maintenance does not warrant classification. The determination of containment and penetration status – isolated or not isolated – should be made in accordance with the appropriate criteria contained in the plant AOPs and EOPs. The 15-minute criterion is included to allow operators time to manually isolate the required penetrations, if possible.

The second condition addresses a condition where containment pressure is greater than the setpoint at which containment energy (heat) removal systems are designed to automatically actuate, and less than one full train of equipment is capable of operating per design. The 15-minute criterion is included to allow operators time to manually start equipment that may not have automatically started, if possible. The inability to start the required equipment indicates that containment heat removal/depressurization systems (e.g., containment) are either lost or performing in a degraded manner.

This event would escalate to a Site Area Emergency in accordance with IC FS1 if there were a concurrent loss or potential loss of either the Fuel Clad or RCS fission product barriers.

CPNPP Basis Reference(s):

1. FSAR Section 6.2.2
2. FRC-Z.1A/B Response to High Containment Pressure
3. NEI 99-01 SU7

Category: S – System Malfunction

Subcategory: 9 – Hazardous Event Affecting Safety Systems

Initiating Condition: Hazardous event affecting a SAFETY SYSTEM needed for the current operating mode

EAL:

SA9.1 Alert

The occurrence of **any** Table S-5 hazardous event

AND EITHER:

- Event damage has caused indications of degraded performance in at least one train of a SAFETY SYSTEM needed for the current operating mode
- The event has caused VISIBLE DAMAGE to a SAFETY SYSTEM component or structure needed for the current operating mode

Table S-5 Hazardous Events
• Seismic event (earthquake) • Internal or external FLOODING event • High winds or tornado strike • FIRE • EXPLOSION • Other events with similar hazard characteristics as determined by the Emergency Coordinator

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

EXPLOSION - A rapid, violent and catastrophic failure of a piece of equipment due to combustion, chemical reaction or overpressurization. A release of steam (from high energy lines or components) or an electrical component failure (caused by short circuits, grounding, arcing, etc.) should not automatically be considered an explosion. Such events require a post-event inspection to determine if the attributes of an explosion are present.

FIRE - Combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical equipment do not constitute fires. Observation of flame is preferred but is NOT required if large quantities of smoke and heat are observed.

FLOODING - A condition where water is entering a room or area faster than installed equipment is capable of removal, resulting in a rise of water level within the room or area.

SAFETY SYSTEM - A system required for safe plant operation, cooling down the plant and/or placing it in the cold shutdown condition, including the ECCS. These are typically systems classified as safety-related (as defined in 10CFR50.2):

Those structures, systems and components that are relied upon to remain functional during and following design basis events to assure:

(1) The integrity of the reactor coolant pressure boundary;

(2) The capability to shut down the reactor and maintain it in a safe shutdown condition;

(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures.

VISIBLE DAMAGE - Damage to a component or structure that is readily observable without measurements, testing, or analysis. The visual impact of the damage is sufficient to cause concern regarding the operability or reliability of the affected component or structure.

Basis:

- The significance of seismic events are discussed under EAL HU2.1 (ref. 1).
- Internal FLOODING may be caused by events such as component failures, equipment misalignment, or outage activity mishaps (ref. 2).
- External flooding may be due to high lake level (ref. 3, 4).
- Seismic Category I structures are analyzed to withstand a sustained, design wind velocity of at least 80 mph. (ref. 5).
- Areas containing functions and systems required for safe shutdown of the plant are identified by fire area (ref. 6, 7).
- An explosion that degrades the performance of a SAFETY SYSTEM train or visibly damages a SAFETY SYSTEM component or structure would be classified under this EAL.

This IC addresses a hazardous event that causes damage to a SAFETY SYSTEM, or a structure containing SAFETY SYSTEM components, needed for the current operating mode. This condition significantly reduces the margin to a loss or potential loss of a fission product barrier, and therefore represents an actual or potential substantial degradation of the level of safety of the plant.

The first condition addresses damage to a SAFETY SYSTEM train that is in service/operation since indications for it will be readily available. The indications of degraded performance should be significant enough to cause concern regarding the operability or reliability of the SAFETY SYSTEM train.

The second condition addresses damage to a SAFETY SYSTEM component that is not in service/operation or readily apparent through indications alone, or to a structure containing SAFETY SYSTEM components. Operators will make this determination based on the totality of available event and damage report information. This is intended to be a brief assessment not requiring lengthy analysis or quantification of the damage.

Escalation of the emergency classification level would be via IC FS1 or RS1.

CPNPP Basis Reference(s):

1. ABN-907 Acts of Nature
2. CPNPP PRA Accident Sequence Analysis “Internal Flooding Sequences”
3. FSAR Section 2.4.3.7 Flood Evaluations for Safe Shutdown Impoundment
4. DBD-CS-071 Maximum Probable Flood
5. FSAR Section 3.3.1.1 Wind Loadings
6. CPNPP Fire Protection Report, Section 5.0 “Fire Safe Shutdown Equipment List”
7. FSAR Section 7.4 Systems Required for Safe Shutdown
8. NEI 99-01 SA9

Category F – Fission Product Barrier Degradation

EAL Group: Hot Conditions (RCS temperature greater than 200ºF); EALs in this category are applicable only in one or more hot operating modes.

EALs in this category represent threats to the defense in depth design concept that precludes the release of highly radioactive fission products to the environment. This concept relies on multiple physical barriers any one of which, if maintained intact, precludes the release of significant amounts of radioactive fission products to the environment. The primary fission product barriers are:

A. Fuel Clad (FC): The Fuel Clad Barrier consists of the cladding material that contains the fuel pellets.

B. Reactor Coolant System (RCS): The RCS Barrier includes the RCS primary side and its connections up to and including the pressurizer safety and relief valves, and other connections up to and including the primary isolation valves.

C. Containment (CNTMT): The Containment Barrier includes the containment building and connections up to and including the outermost containment isolation valves. This barrier also includes the main steam, feedwater, and blowdown line extensions outside the containment building up to and including the outermost secondary side isolation valve. Containment Barrier thresholds are used as criteria for escalation of the ECL from Alert to a Site Area Emergency or a General Emergency.

The EALs in this category require evaluation of the loss and potential loss thresholds listed in the fission product barrier matrix of Table F-1 (Attachment 2). “Loss” and “Potential Loss” signify the relative damage and threat of damage to the barrier. “Loss” means the barrier no longer assures containment of radioactive materials. “Potential Loss” means integrity of the barrier is threatened and could be lost if conditions continue to degrade. The number of barriers that are lost or potentially lost and the following criteria determine the appropriate emergency classification level:

Alert:
Any loss or any potential loss of either Fuel Clad or RCS

Site Area Emergency:
Loss or potential loss of any two barriers

General Emergency:
Loss of any two barriers and loss or potential loss of third barrier

The logic used for emergency classification based on fission product barrier monitoring should reflect the following considerations:

- The Fuel Clad Barrier and the RCS Barrier are weighted more heavily than the Containment Barrier.
- Unusual Event ICs associated with RCS and Fuel Clad Barriers are addressed under System Malfunction ICs.

- For accident conditions involving a radiological release, evaluation of the fission product barrier thresholds will need to be performed in conjunction with dose assessments to ensure correct and timely escalation of the emergency classification. For example, an evaluation of the fission product barrier thresholds may result in a Site Area Emergency classification while a dose assessment may indicate that an EAL for General Emergency IC RG1 has been exceeded.
- The fission product barrier thresholds specified within a scheme reflect plant-specific CPNPP design and operating characteristics.
- As used in this category, the term RCS leakage encompasses not just those types defined in Technical Specifications but also includes the loss of RCS mass to any location– inside the primary containment, an interfacing system, or outside of the primary containment. The release of liquid or steam mass from the RCS due to the as-designed/expected operation of a relief valve is not considered to be RCS leakage.
- At the Site Area Emergency level, EAL users should maintain cognizance of how far present conditions are from meeting a threshold that would require a General Emergency declaration. For example, if the Fuel Clad and RCS fission product barriers were both lost, then there should be frequent assessments of containment radioactive inventory and integrity. Alternatively, if both the Fuel Clad and RCS fission product barriers were potentially lost, the Emergency Coordinator would have more assurance that there was no immediate need to escalate to a General Emergency.

Category: Fission Product Barrier Degradation

Subcategory: N/A

Initiating Condition: **Any** loss or **any** potential loss of either Fuel Clad or RCS

EAL:

FA1.1	**Alert**
Any loss or **any** potential loss of either Fuel Clad or RCS (Table F-1)	

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

Fuel Clad, RCS and Containment comprise the fission product barriers. Table F-1 (Attachment 2) lists the fission product barrier thresholds, bases and references.

At the Alert classification level, Fuel Clad and RCS barriers are weighted more heavily than the Containment barrier. Unlike the Containment barrier, loss or potential loss of either the Fuel Clad or RCS barrier may result in the relocation of radioactive materials or degradation of core cooling capability. Note that the loss or potential loss of Containment barrier in combination with loss or potential loss of either Fuel Clad or RCS barrier results in declaration of a Site Area Emergency under EAL FS1.1

CPNPP Basis Reference(s):

1. NEI 99-01 FA1

Category: Fission Product Barrier Degradation

Subcategory: N/A

Initiating Condition: Loss or potential loss of **any** two barriers

EAL:

FS1.1	**Site Area Emergency**
Loss or potential loss of **any** two barriers (Table F-1)	

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

Fuel Clad, RCS and Containment comprise the fission product barriers. Table F-1 (Attachment 2) lists the fission product barrier thresholds, bases and references.

At the Site Area Emergency classification level, each barrier is weighted equally. A Site Area Emergency is therefore appropriate for any combination of the following conditions:

- One barrier loss and a second barrier loss (i.e., loss - loss)
- One barrier loss and a second barrier potential loss (i.e., loss - potential loss)
- One barrier potential loss and a second barrier potential loss (i.e., potential loss - potential loss)

At the Site Area Emergency classification level, the ability to dynamically assess the proximity of present conditions with respect to the threshold for a General Emergency is important. For example, the existence of Fuel Clad and RCS Barrier loss thresholds in addition to offsite dose assessments would require continual assessments of radioactive inventory and Containment integrity in anticipation of reaching a General Emergency classification. Alternatively, if both Fuel Clad and RCS potential loss thresholds existed, the Emergency Coordinator would have greater assurance that escalation to a General Emergency is less imminent.

CPNPP Basis Reference(s):

1. NEI 99-01 FS1

Category: Fission Product Barrier Degradation

Subcategory: N/A

Initiating Condition: Loss of **any** two barriers and loss or potential loss of third barrier

EAL:

FG1.1 General Emergency
Loss of **any** two barriers **AND** Loss or potential loss of third barrier (Table F-1)

Mode Applicability:

1 - Power Operation, 2 - Startup, 3 - Hot Standby, 4 - Hot Shutdown

Definition(s):

None

Basis:

Fuel Clad, RCS and Containment comprise the fission product barriers. Table F-1 (Attachment 2) lists the fission product barrier thresholds, bases and references.

At the General Emergency classification level each barrier is weighted equally. A General Emergency is therefore appropriate for any combination of the following conditions:

- Loss of Fuel Clad, RCS and Containment barriers
- Loss of Fuel Clad and RCS barriers with potential loss of Containment barrier
- Loss of RCS and Containment barriers with potential loss of Fuel Clad barrier
- Loss of Fuel Clad and Containment barriers with potential loss of RCS barrier

CPNPP Basis Reference(s):

1. NEI 99-01 FG1

Introduction

Table F-1 lists the threshold conditions that define the Loss and Potential Loss of the three fission product barriers (Fuel Clad, Reactor Coolant System, and Containment). The table is structured so that each of the three barriers occupies adjacent columns. Each fission product barrier column is further divided into two columns; one for Loss thresholds and one for Potential Loss thresholds.

The first column of the table (to the left of the Fuel Clad Loss column) lists the categories (types) of fission product barrier thresholds. The fission product barrier categories are:

A. RCS or SG Tube Leakage

B. Inadequate Heat removal

C. CNTMT Radiation / RCS Activity

D. CNTMT Integrity or Bypass

E. Emergency Coordinator Judgment

Each category occupies a row in Table F-1 thus forming a matrix defined by the categories. The intersection of each row with each Loss/Potential Loss column forms a cell in which one or more fission product barrier thresholds appear. If NEI 99-01 does not define a threshold for a barrier Loss/Potential Loss, the word “None” is entered in the cell.

Thresholds are assigned sequential numbers within each Loss and Potential Loss column beginning with number one. In this manner, a threshold can be identified by its category title and number. For example, the first Fuel Clad barrier Loss in Category A would be assigned “FC Loss A.1,” the third Containment barrier Potential Loss in Category C would be assigned “CNTMT P-Loss C.3,” etc.

If a cell in Table F-1 contains more than one numbered threshold, each of the numbered thresholds, if exceeded, signifies a Loss or Potential Loss of the barrier. It is not necessary to exceed all of the thresholds in a category before declaring a barrier Loss/Potential Loss.

Subdivision of Table F-1 by category facilitates association of plant conditions to the applicable fission product barrier Loss and Potential Loss thresholds. This structure promotes a systematic approach to assessing the classification status of the fission product barriers.

When equipped with knowledge of plant conditions related to the fission product barriers, the EAL-user first scans down the category column of Table F-1, locates the likely category and then reads across the fission product barrier Loss and Potential Loss thresholds in that category to determine if a threshold has been exceeded. If a threshold has not been exceeded, the EAL-user proceeds to the next likely category and continues review of the thresholds in the new category

If the EAL-user determines that any threshold has been exceeded, by definition, the barrier is lost or potentially lost – even if multiple thresholds in the same barrier column are exceeded, only that one barrier is lost or potentially lost. The EAL-user must examine each of the three fission product barriers to determine if other barrier thresholds in the category are lost or potentially lost. For example, if containment radiation is sufficiently high, a Loss of the Fuel Clad and RCS barriers and a Potential Loss of the Containment barrier can occur. Barrier

Losses and Potential Losses are then applied to the algorithms given in EALs FG1.1, FS1.1, and FA1.1 to determine the appropriate emergency classification.

In the remainder of this Attachment, the Fuel Clad barrier threshold bases appear first, followed by the RCS barrier and finally the Containment barrier threshold bases. In each barrier, the bases are given according category Loss followed by category Potential Loss beginning with Category A, then B,…, E.

Table F-1 Fission Product Barrier Threshold Matrix

Category	Fuel Clad (FC) Barrier		Reactor Coolant System (RCS) Barrier		Containment (CNTMT) Barrier	
	Loss	**Potential Loss**	**Loss**	**Potential Loss**	**Loss**	**Potential Loss**
A RCS or SG Tube Leakage	None	None	1. An automatic or manual ECCS (SI) actuation required by **EITHER:** • UNISOLABLE RCS leakage • SG tube RUPTURE	1. Operation of a standby charging pump is required by **EITHER:** • UNISOLABLE RCS leakage • SG tube leakage 2. CSFST Integrity-RED Path conditions met	1. A leaking or RUPTURED SG is FAULTED outside of containment	None
B Inadequate Heat Removal	1. CSFST Core Cooling-RED Path conditions met	1. CSFST Core Cooling-ORANGE Path conditions met 2. CSFST Heat Sink-RED Path conditions met **AND** Heat sink is required	None	1. CSFST Heat Sink-RED Path conditions met **AND** Heat sink is required	None	1. CSFST Core Cooling-RED Path conditions met **AND** Restoration procedures **not** effective within 15 min. (Note 1)
C CNTMT Radiation / RCS Activity	1. Containment radiation greater than 85 R/hr CTEu16 Containment HRRM (u-RE-6290A), or CTWu17 Containment HRRM (u-RE-6290B) 2. Dose equivalent I-131 coolant activity greater than 300 µCi/cc 3. Gross Failed Fuel Monitor, FFLu60 (u-RE-0406), radiation greater than 1.0E04 µCi/cc	None	1. Containment radiation greater than 5 R/hr CTEu16 Containment HRRM (u-RE-6290A), or CTWu17 Containment HRRM (u-RE-6290B)	None	None	1. Containment radiation greater than 2,110 R/hr CTEu16 Containment HRRM (u-RE-6290A), or CTWu17 Containment HRRM (u-RE-6290B)
D CNTMT Integrity or Bypass	None	None	None	None	1. Containment isolation is required **AND EITHER:** • Containment integrity has been lost based on Emergency Coordinator judgment • UNISOLABLE pathway from Containment to the environment exists 2. Indications of RCS leakage outside of Containment	1. CSFST Containment-RED Path conditions met 2. Containment hydrogen concentration greater than 4% 3. Containment pressure greater than 18 psig with **neither** Containment Spray system train operating greater than or equal to 15 min. (Note 1)
E EC Judgment	1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the fuel clad barrier	1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the fuel clad barrier	1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the RCS barrier	1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the RCS barrier	1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the Containment barrier	1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the Containment barrier

Barrier: Fuel Clad

Category: A. RCS or SG Tube Leakage

Degradation Threat: Loss

Threshold:

None

Barrier: Fuel Clad

Category: A. RCS or SG Tube Leakage

Degradation Threat: Potential Loss

Threshold:

None

Barrier: Fuel Clad

Category: B. Inadequate Heat Removal

Degradation Threat: Loss

Threshold:

1. CSFST Core Cooling-**RED** Path conditions met

Definition(s):

None

Basis:

Critical Safety Function Status Tree (CSFST) Core Cooling-RED Path indicates significant core exit superheating and core uncovery. The CSFSTs are normally monitored using the SPDS display on the Plant Computer (ref. 1).

This reading indicates temperatures within the core are sufficient to cause significant superheating of reactor coolant.

CPNPP Basis Reference(s):

1. FRC-0.1A/B Response to Inadequate Core Cooling
2. NEI 99-01 Inadequate Heat Removal Fuel Clad Loss 2.A

Barrier: Fuel Clad

Category: B. Inadequate Heat Removal

Degradation Threat: Potential Loss

Threshold:

1. CSFST Core Cooling-**ORANGE** Path conditions met

Definition(s):

None

Basis:

Critical Safety Function Status Tree (CSFST) Core Cooling-ORANGE path indicates indicates subcooling has been lost and that some fuel clad damage may potentially occur. The CSFSTs are normally monitored using the SPDS display on the Plant Computer (ref. 1, 2).

This reading indicates a reduction in reactor vessel water level sufficient to allow the onset of heat-induced cladding damage.

CPNPP Basis Reference(s):

1. FRC-0.1A/B Response to Inadequate Core Cooling
2. FRC-0.2A/B Response to Degraded Core Cooling
3. NEI 99-01 Inadequate Heat Removal Fuel Clad Loss 2.A

Barrier: Fuel Clad

Category: B. Inadequate Heat Removal

Degradation Threat: Potential Loss

Threshold:

2. CSFST Heat Sink-**RED** Path conditions met

   AND

   Heat sink is required

Definition(s):

None

Basis:

In combination with RCS Potential Loss B.1, meeting this threshold results in a Site Area Emergency.

Critical Safety Function Status Tree (CSFST) Heat Sink-RED Path indicates the ultimate heat sink function is under extreme challenge and that some fuel clad damage may potentially occur (ref. 1).

The CSFSTs are normally monitored using the SPDS display on the Plant Computer (ref. 1).

The phrase "and heat sink required" precludes the need for classification for conditions in which RCS pressure is less than SG pressure or Heat Sink-RED path entry was created through operator action directed by an ERG. For example, FRH-0.1 is entered from CSFST Heat Sink-Red. Step 1 tells the operator to determine if heat sink is required by checking that RCS pressure is greater than any non-faulted SG pressure and RCS temperature is greater than 350ºF. If these conditions exist, Heat Sink is required. Otherwise, the operator is to either return to the procedure and step in effect and place RHR in service for heat removal. For large LOCA events inside the Containment, the SGs are moot because heat removal through the containment heat removal systems takes place. Therefore, Heat Sink Red should not be required and, should not be assessed for EAL classification because a LOCA event alone should not require higher than an Alert classification. (ref. 1).

This condition indicates an extreme challenge to the ability to remove RCS heat using the steam generators (i.e., loss of an effective secondary-side heat sink). This condition represents a potential loss of the Fuel Clad Barrier. In accordance with EOPs, there may be unusual accident conditions during which operators intentionally reduce the heat removal capability of the steam generators; during these conditions, classification using threshold is not warranted.

CPNPP Basis Reference(s):

1. FRH-0.1A/B Response to Loss of Secondary Heat Sink
2. NEI 99-01 Inadequate Heat Removal Fuel Clad Loss 2.B

Barrier: Fuel Clad

Category: C. CNTMT Radiation / RCS Activity

Degradation Threat: Loss

Threshold:

1. Containment radiation greater than 85 R/hr
CTEu16 Containment HRRM (u-RE-6290A), or
CTWu17 Containment HRRM (u-RE-6290B)

Definition(s):

None

Basis:

Containment radiation monitor readings greater than 85 R/hr indicate the release of reactor coolant, with elevated activity indicative of fuel damage, into the Containment. The reading is derived assuming the instantaneous release and dispersal of the reactor coolant noble gas and iodine inventory associated with a 2% clad failures into the Containment atmosphere. Reactor coolant concentrations of this magnitude are several times larger than the maximum concentrations (including iodine spiking) allowed within technical specifications and are therefore indicative of fuel damage. This value is higher than that specified for RCS Loss C.1 (ref. 2, 3).

Per NUS-174, the design basis CPNPP RCS specific activity for 1% fuel defects is 340 µCi/gm; therefore, a threshold corresponding to 2% fuel clad damage correlates to a coolant activity of 680 µCi/gm. VL-03-000032 Figure 2A/2B (CRM2) corresponds to approximately 50% clad damage released to the containment atmosphere. Figure 2A/2B provides several potential limits depending on the pressure of the RCS and the presence of containment spray. The high RCS pressure with containment spray is the most limiting threshold; however, per NEI 99-01, the fuel clad barrier loss threshold should represent a loss of both the fuel clad and RCS barriers. Therefore, the value of curve representing low RCS pressure with spray was used. The change in dose rates based on amount of fuel defects is a linear function; therefore, the threshold at 2% fuel defects is: 2120R/hr *(2% / 50%) = 85 R/hr (ref. 2).

The Containment High Range Radiation Monitors (HRRMs) provide indication of radiation levels in Containment during and after postulated accidents. The monitors are two ion chamber detectors located on the 905' level of Containment approximately 90° apart. The range of each monitor is 1 to 10^8 R/hr. The output of each detector is fed to an RM-80 located outside Containment. The RM-80 provides monitoring, alarming, and recording functions for the monitor channel. The RM-80 works in conjunction with the PC-11, RM-21, and RM-23 assemblies. (ref. 1)

The radiation monitor reading corresponds to an instantaneous release of all reactor coolant mass into the containment, assuming that reactor coolant activity equals 300 μCi/gm dose equivalent I-131. Reactor coolant activity above this level is greater than that expected for iodine spikes and corresponds to an approximate range of 2% to 5% fuel clad damage. Since this condition indicates that a significant amount of fuel clad damage has occurred, it represents a loss of the Fuel Clad Barrier.

The radiation monitor reading in this threshold is higher than that specified for RCS Barrier Loss threshold C.1 since it indicates a loss of both the Fuel Clad Barrier and the RCS Barrier. Note that a combination of the two monitor readings appropriately escalates the ECL to a Site Area Emergency.

CPNPP Basis Reference(s):

1. DBD-EE-023 Radiation Monitoring System
2. Evaluation performed by Design Engineering & Analysis (Andrea Lemons) (AI-CR-2014-012646-15)
3. EPP-312 Core Damage Assessment
4. NEI 99-01 CNTMT Radiation / RCS Activity Fuel Clad Loss 3.A

Barrier: Fuel Clad

Category: C. CNTMT Radiation / RCS Activity

Degradation Threat: Loss

Threshold:

2. Dose equivalent I-131 coolant activity greater than 300 μCi/cc

Definition(s):

None

Basis:

This threshold indicates that RCS radioactivity concentration is greater than 300 μCi/gm dose equivalent I-131. Reactor coolant activity above this level is greater than that expected for iodine spikes and corresponds to an approximate range of 2% to 5% fuel clad damage. Since this condition indicates that a significant amount of fuel clad damage has occurred, it represents a loss of the Fuel Clad Barrier.

It is recognized that sample collection and analysis of reactor coolant with highly elevated activity levels could require several hours to complete. Nonetheless, a sample-related threshold is included as a backup to other indications.

There is no Potential Loss threshold associated with RCS Activity / Containment Radiation.

CPNPP Basis Reference(s):

1. NEI 99-01 CNTMT Radiation / RCS Activity Fuel Clad Loss 3.B

Barrier: Fuel Clad

Category: C. CNTMT Radiation / RCS Activity

Degradation Threat: Loss

Threshold:

3. Gross Failed Fuel Monitor, FFLu60 (u-RE-0406), radiation greater than 1.0E04 µCi/ml

Definition(s):

None

Basis:

The normal Chemical and Volume Control System (CVCS) charging and letdown flow path allows purification of the reactor coolant and control of the RCS volume while maintaining a continuous feed and bleed flow between the RCS and the CVCS. Reactor coolant is first "letdown" from the RCS through a regenerative heat exchanger, which minimizes heat losses from the RCS. Additional cooling takes place in a letdown heat exchanger that acts as the heat sink for the system. Downstream of the letdown heat exchanger pressure control valve and upstream of the mixed bed demineralizers, the letdown stream passes by a Geiger-Mueller radiation detector, FFLu60 (u-RE-0406), mounted on the reactor coolant letdown line to monitor coolant activity and warn of fission products in the letdown coolant if a fuel element failure occurs. Detection of increased coolant activity may be indicative of failed fuel. The monitor initiates Alert and High alarms in the Control Room (PC-11 and Plant Computer). (ref. 1).

Core Damage Assessment Guidelines (VL-03-000032) which was incorporated into EPP-312 "Core Damage Assessment" provides the basis for loss of the Fuel Cladding as monitored by the Gross Failed Fuel Monitor. The setpoint recommended by Westinghouse is 1E+04 µCi/ml (ref. 2, 3).

FFLu60 (u-RE-0406) has a range of 1E-2 – 1E+7 µCi/ml.

CPNPP Basis Reference(s):

1. DBD-EE-023 Radiation Monitoring System
2. Evaluation performed by Design Engineering & Analysis (Andrea Lemons) (AI-CR-2014-012646-15)
3. EPP-312 Core Damage Assessment
4. NEI 99-01 Other Indications Fuel Clad Loss 5.A

Barrier: Fuel Clad

Category: C. CNTMT Radiation / RCS Activity

Degradation Threat: Potential Loss

Threshold:

None

Barrier: Fuel Clad

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Loss

Threshold:

None

Barrier: Fuel Clad

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Potential Loss

Threshold:

None

Barrier: Fuel Clad

Category: E. Emergency Coordinator Judgment

Degradation Threat: Loss

Threshold:

1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the Fuel Clad barrier

Definition(s):

None

Basis:

The Emergency Coordinator judgment threshold addresses any other factors relevant to determining if the Fuel Clad barrier is lost. Such a determination should include imminent barrier degradation, barrier monitoring capability and dominant accident sequences.

- Imminent barrier degradation exists if the degradation will likely occur within relatively short period of time based on a projection of current safety system performance. The term “imminent” refers to recognition of the inability to reach safety acceptance criteria before completion of all checks.
- Barrier monitoring capability is decreased if there is a loss or lack of reliable indicators. This assessment should include instrumentation operability concerns, readings from portable instrumentation and consideration of offsite monitoring results.
- Dominant accident sequences lead to degradation of all fission product barriers and likely entry to the EOPs. The Emergency Coordinator should be mindful of the Loss of AC power (Station Blackout) and ATWS EALs to assure timely emergency classification declarations.

This threshold addresses any other factors that are to be used by the Emergency Coordinator in determining whether the Fuel Clad barrier is lost

CPNPP Basis Reference(s):

1. NEI 99-01 Emergency Director Judgment Fuel Clad Loss 6.A

Barrier: Fuel Clad

Category: E. Emergency Coordinator Judgment

Degradation Threat: Potential Loss

Threshold:

1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the Fuel Clad barrier

Basis:

The Emergency Coordinator judgment threshold addresses any other factors relevant to determining if the Fuel Clad barrier is potentially lost. Such a determination should include imminent barrier degradation, barrier monitoring capability and dominant accident sequences.

- Imminent barrier degradation exists if the degradation will likely occur within relatively short period of time based on a projection of current safety system performance. The term “imminent” refers to recognition of the inability to reach safety acceptance criteria before completion of all checks.
- Barrier monitoring capability is decreased if there is a loss or lack of reliable indicators. This assessment should include instrumentation operability concerns, readings from portable instrumentation and consideration of offsite monitoring results.
- Dominant accident sequences lead to degradation of all fission product barriers and likely entry to the EOPs. The Emergency Coordinator should be mindful of the Loss of AC power (Station Blackout) and ATWS EALs to assure timely emergency classification declarations.

This threshold addresses any other factors that are to be used by the Emergency Coordinator in determining whether the Fuel Clad barrier is potentially lost. The Emergency Coordinator should also consider whether or not to declare the barrier potentially lost in the event that barrier status cannot be monitored.

CPNPP Basis Reference(s):

1. NEI 99-01 Emergency Director Judgment Potential Fuel Clad Loss 6.A

Barrier: Reactor Coolant System

Category: A. RCS or SG Tube Leakage

Degradation Threat: Loss

Threshold:

1. An automatic or manual ECCS (SI) actuation required by **EITHER:**
   - UNISOLABLE RCS leakage
   - SG tube RUPTURE

Definition(s):

UNISOLABLE - An open or breached system line that cannot be isolated, remotely or locally.

RUPTURE - The condition of a steam generator in which primary-to-secondary leakage is of sufficient magnitude to require a safety injection.

Basis:

ECCS (SI) actuation is caused by (ref. 1):

- Pressurizer low pressure less than 1820 psig
- Steamline low pressure less than 610 psig
- Containment high pressure greater than 3.0 psig

This threshold is based on an UNISOLABLE RCS leak of sufficient size to require an automatic or manual actuation of the Emergency Core Cooling System (ECCS). This condition clearly represents a loss of the RCS Barrier.

This threshold is applicable to unidentified and pressure boundary leakage, as well as identified leakage. It is also applicable to UNISOLABLE RCS leakage through an interfacing system. The mass loss may be into any location – inside containment, to the secondary-side (i.e., steam generator tube leakage) or outside of containment.

A steam generator with primary-to-secondary leakage of sufficient magnitude to require a safety injection is considered to be RUPTURED. If a RUPTURED steam generator is also FAULTED outside of containment, the declaration escalates to a Site Area Emergency since the Containment Barrier Loss threshold 1.A will also be met.

CPNPP Basis Reference(s):

1. EOP-0.0A/B Reactor Trip or Safety Injection
2. EOP-3.0A/B Steam Generator Tube Rupture
3. NEI 99-01 RCS or SG Tube Leakage Reactor Coolant System Loss 1.A

Barrier: Reactor Coolant System

Category: A. RCS or SG Tube Leakage

Degradation Threat: Potential Loss

Threshold:

1. Operation of a standby charging pump is required by **EITHER:**
    - UNISOLABLE RCS leakage
    - SG tube leakage

Definition(s):

UNISOLABLE - An open or breached system line that cannot be isolated, remotely or locally.

Basis:

The Chemical and Volume Control System (CVCS) includes three charging pumps (one positive displacement pump and two centrifugal charging pumps) that take suction from the volume control tank and return the cooled, purified reactor coolant to the RCS. The centrifugal charging pumps in the CVCS also serve as the high-head safety injection pumps in the Emergency Core Cooling System. Positive displacement pump capacity is 98 gpm. The capacity of each centrifugal pump is 150 gpm. A second charging pump being required (positive displacement or centrifugal) is indicative of a substantial RCS leak. (ref. 1, 2, 3)

This threshold is based on an UNISOLABLE RCS leak that results in the inability to maintain pressurizer level within specified limits by operation of a normally used charging (makeup) pump, but an ECCS (SI) actuation has not occurred. The threshold is met when an operating procedure, or operating crew supervision, directs that a standby charging (makeup) pump be placed in service to restore and maintain pressurizer level.

This threshold is applicable to unidentified and pressure boundary leakage, as well as identified leakage. It is also applicable to UNISOLABLE RCS leakage through an interfacing system. The mass loss may be into any location – inside containment, to the secondary-side (i.e., steam generator tube leakage) or outside of containment.

If a leaking steam generator is also FAULTED outside of containment, the declaration escalates to a Site Area Emergency since the Containment Barrier Loss threshold 1.A will also be met.

CPNPP Basis Reference(s):

1. FSAR 9.3.4
2. FSAR Table 9.3-7
3. SOP-103A/B Chemical and Volume Control System
4. NEI 99-01 RCS or SG Tube Leakage Reactor Coolant System Potential Loss 1.A

Barrier: Reactor Coolant System

Category: A. RCS or SG Tube Leakage

Degradation Threat: Potential Loss

Threshold:

2. CSFST Integrity-**RED** Path conditions met

Definition(s):

None

Basis:

Critical Safety Function Status Tree (CSFST) RCS Integrity-RED path indicates the RCS barrier is under significant challenge (ref. 1).

This condition indicates an extreme challenge to the integrity of the RCS pressure boundary due to pressurized thermal shock – a transient that causes rapid RCS cooldown while the RCS is in Mode 3 or higher (i.e., hot and pressurized).

CPNPP Basis Reference(s):

1. FRP-0.1A/B Response to Imminent Pressurized Thermal Shock Condition
2. NEI 99-01 RCS or SG Tube Leakage Reactor Coolant System Potential Loss 1.B

Barrier: Reactor Coolant System

Category: B. Inadequate Heat Removal

Degradation Threat: Loss

Threshold:

None

Barrier: Reactor Coolant System

Category: B. Inadequate Heat Removal

Degradation Threat: Potential Loss

Threshold:

1. CSFST Heat Sink-**RED** path conditions met

   AND

   Heat sink is required

Definition(s):

None

Basis:

In combination with FC Potential Loss B.2, meeting this threshold results in a Site Area Emergency.

Critical Safety Function Status Tree (CSFST) Heat Sink-RED Path indicates the ultimate heat sink function is under extreme challenge and that some fuel clad damage may potentially occur (ref. 1).

The CSFSTs are normally monitored using the SPDS display on the Plant Computer (ref. 1).

The phrase “and heat sink required” precludes the need for classification for conditions in which RCS pressure is less than SG pressure or Heat Sink-RED path entry was created through operator action directed by an ERG. For example, FRH-0.1 is entered from CSFST Heat Sink-Red. Step 1 tells the operator to determine if heat sink is required by checking that RCS pressure is greater than any non-faulted SG pressure and RCS temperature is greater than 350ºF. If these conditions exist, Heat Sink is required. Otherwise, the operator is to either return to the procedure and step in effect and place RHR in service for heat removal. For large LOCA events inside the Containment, the SGs are moot because heat removal through the containment heat removal systems takes place. Therefore, Heat Sink Red should not be required and, should not be assessed for EAL classification because a LOCA event alone should not require higher than an Alert classification. (ref. 1).

This condition indicates an extreme challenge to the ability to remove RCS heat using the steam generators (i.e., loss of an effective secondary-side heat sink). This condition represents a potential loss of the RCS Barrier. In accordance with EOPs, there may be unusual accident conditions during which operators intentionally reduce the heat removal capability of the steam generators; during these conditions, classification using threshold is not warranted.

Meeting this threshold results in a Site Area Emergency because this threshold is identical to Fuel Clad Barrier Potential Loss threshold B.2; both will be met. This condition warrants a Site Area Emergency declaration because inadequate RCS heat removal may result in fuel heat-up sufficient to damage the cladding and increase RCS pressure to the point where mass will be lost from the system.

CPNPP Basis Reference(s):

1. FRH-0.1A/B Response to Loss of Secondary Heat Sink
2. NEI 99-01 Inadequate Heat Removal RCS Loss 2.B

Barrier: Reactor Coolant System

Category: C. CNTMT Radiation/ RCS Activity

Degradation Threat: Loss

Threshold:

1. Containment radiation greater than 5 R/hr
   CTEu16 Containment HRRM (u-RE-6290A), or
   CTWu17 Containment HRRM (u-RE-6290B)

Definition(s):

N/A

Basis:

As part of the elimination of the Post-Accident Sampling system, Westinghouse performed analysis for Comanche Peak on Core Damage Assessment Guidelines (VL-03-000032) which was incorporated into EPP-312 “Core Damage Assessment”. For setpoint CRM1, Westinghouse assumptions match the requirements of NEI 99-01 for RCS barrier loss with the exception that the level of radioactivity in the RCS is assumed to be at 10% of Technical Specifications levels rather than 100% as recommended by NEI 99-01. However, this adds conservatism to this threshold. The limiting maximum value found in Figure 1A is 4.75 R/hr. This value is time dependent and corresponds to an hour after shutdown. This value has been rounded to 5 R/hr for instrument readability (ref. 1, 3, 4, 5).

The Containment High Range Radiation Monitors (HRRMs) provide indication of radiation levels in Containment during and after postulated accidents. The monitors are two ion chamber detectors located on the 905’ level of Containment approximately 90° apart. The range of each monitor is 1 to 10^8 R/hr. The output of each detector is fed to an RM-80 located outside Containment.

The RM-80 provides monitoring, alarming, and recording functions for the monitor channel. The RM-80 works in conjunction with the PC-11, RM-21, and RM-23 assemblies. (ref. 2)

The radiation monitor reading corresponds to an instantaneous release of all reactor coolant mass into the containment, assuming that reactor coolant activity equals Technical Specification allowable limits. This value is lower than that specified for Fuel Clad Barrier Loss threshold C.1 since it indicates a loss of the RCS Barrier only.

There is no Potential Loss threshold associated with RCS Activity / Containment Radiation.

CPNPP Basis Reference(s):

1. Technical Specifications Table 3.3.3-1
2. DBD-EE-023 Radiation Monitoring System
3. Evaluation performed by Design Engineering & Analysis (Andrea Lemons) (AI-CR-2014-012646-15)
4. Technical Specifications B3.3.3
5. EPP-312 Core Damage Assessment
6. NEI 99-01 CNTMT Radiation / RCS Activity RCS Loss 3.A

Barrier: Reactor Coolant System

Category: B. CNTMT Radiation/ RCS Activity

Degradation Threat: Potential Loss

Threshold:

None

Barrier: Reactor Coolant System

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Loss

Threshold:

None

Barrier: Reactor Coolant System

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Potential Loss

Threshold:

None

Barrier: Reactor Coolant System

Category: E. Emergency Coordinator Judgment

Degradation Threat: Loss

Threshold:

1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the RCS barrier

Definition(s):

None

Basis:

The Emergency Coordinator judgment threshold addresses any other factors relevant to determining if the RCS barrier is lost. Such a determination should include imminent barrier degradation, barrier monitoring capability and dominant accident sequences.

- Imminent barrier degradation exists if the degradation will likely occur within relatively short period of time based on a projection of current safety system performance. The term “imminent” refers to recognition of the inability to reach safety acceptance criteria before completion of all checks.
- Barrier monitoring capability is decreased if there is a loss or lack of reliable indicators. This assessment should include instrumentation operability concerns, readings from portable instrumentation and consideration of offsite monitoring results.
- Dominant accident sequences lead to degradation of all fission product barriers and likely entry to the EOPs. The Emergency Coordinator should be mindful of the Loss of AC power (Station Blackout) and ATWS EALs to assure timely emergency classification declarations.

This threshold addresses any other factors that may be used by the Emergency Coordinator in determining whether the RCS Barrier is lost.

CPNPP Basis Reference(s):

1. NEI 99-01 Emergency Director Judgment RCS Loss 6.A

Barrier: Reactor Coolant System

Category: E. Emergency Coordinator Judgment

Degradation Threat: Potential Loss

Threshold:

1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the RCS barrier

Definition(s):

None

Basis:

The Emergency Coordinator judgment threshold addresses any other factors relevant to determining if the RCS barrier is potentially lost. Such a determination should include imminent barrier degradation, barrier monitoring capability and dominant accident sequences.

- Imminent barrier degradation exists if the degradation will likely occur within relatively short period of time based on a projection of current safety system performance. The term "imminent" refers to recognition of the inability to reach safety acceptance criteria before completion of all checks.
- Barrier monitoring capability is decreased if there is a loss or lack of reliable indicators. This assessment should include instrumentation operability concerns, readings from portable instrumentation and consideration of offsite monitoring results.
- Dominant accident sequences lead to degradation of all fission product barriers and likely entry to the EOPs. The Emergency Coordinator should be mindful of the Loss of AC power (Station Blackout) and ATWS EALs to assure timely emergency classification declarations.

This threshold addresses any other factors that may be used by the Emergency Coordinator in determining whether the RCS Barrier is potentially lost. The Emergency Director should also consider whether or not to declare the barrier potentially lost in the event that barrier status cannot be monitored.

CPNPP Basis Reference(s):

1. NEI 99-01 Emergency Director Judgment RCS Potential Loss 6.A

Barrier: Containment

Category: A. RCS or SG Tube Leakage

Degradation Threat: Loss

Threshold:

1. A leaking or RUPTURED SG is FAULTED outside of containment

Definition(s):

FAULTED - The term applied to a steam generator that has a steam leak on the secondary side of sufficient size to cause an uncontrolled drop in steam generator pressure or the steam generator to become completely depressurized.

RUPTURED - The condition of a steam generator in which primary-to-secondary leakage is of sufficient magnitude to require a safety injection.

Basis:

This threshold addresses a leaking or RUPTURED Steam Generator (SG) that is also FAULTED outside of containment. The condition of the SG, whether leaking or RUPTURED, is determined in accordance with the thresholds for RCS Barrier Potential Loss A.1 and Loss A.1, respectively. This condition represents a bypass of the containment barrier.

FAULTED is a defined term within the NEI 99-01 methodology; this determination is not necessarily dependent upon entry into, or diagnostic steps within, an EOP. For example, if the pressure in a steam generator is decreasing uncontrollably (part of the FAULTED definition) and the FAULTED steam generator isolation procedure is not entered because EOP user rules are dictating implementation of another procedure to address a higher priority condition, the steam generator is still considered FAULTED for emergency classification purposes.

The FAULTED criterion establishes an appropriate lower bound on the size of a steam release that may require an emergency classification. Steam releases of this size are readily observable with normal Control Room indications. The lower bound for this aspect of the containment barrier is analogous to the lower bound criteria specified in IC SU4 for the fuel clad barrier (i.e., RCS activity values) and IC SU5 for the RCS barrier (i.e., RCS leak rate values).

This threshold also applies to prolonged steam releases necessitated by operational considerations such as the forced steaming of a leaking or RUPTURED steam generator directly to atmosphere to cooldown the plant, or to drive an auxiliary (emergency) feed water pump. These types of conditions will result in a significant and sustained release of radioactive steam to the environment (and are thus similar to a FAULTED condition). The inability to isolate the steam flow without an adverse effect on plant cooldown meets the intent of a loss of containment.

Steam releases associated with the expected operation of a SG power operated relief valve or safety relief valve do not meet the intent of this threshold. Such releases may occur intermittently for a short period of time following a reactor trip as operators process through emergency operating procedures to bring the plant to a stable condition and prepare to initiate a plant cooldown. Steam releases associated with the unexpected operation of a valve (e.g., a stuck-open safety valve) do meet this threshold.

Following an SG tube leak or rupture, there may be minor radiological releases through a secondary-side system component (e.g., air ejectors, glad seal exhausters, valve packing, etc.). These types of releases do not constitute a loss or potential loss of containment but should be evaluated using the Recognition Category R ICs.

The ECLs resulting from primary-to-secondary leakage, with or without a steam release from the FAULTED SG, are summarized below.

	Affected SG is FAULTED Outside of Containment?	
P-to-S Leak Rate	**Yes**	**No**
Less than or equal to 25 gpm	No classification	No classification
Greater than 25 gpm	Unusual Event per SU5.1	Unusual Event per SU5.1
Requires operation of a standby charging (makeup) pump (*RCS Barrier Potential Loss*)	Site Area Emergency per FS1.1	Alert per FA1.1
Requires an automatic or manual ECCS (SI) actuation (*RCS Barrier Loss*)	Site Area Emergency per FS1.1	Alert per FA1.1

There is no Potential Loss threshold associated with RCS or SG Tube Leakage.

CPNPP Basis Reference(s):

1. EOP-3.0 Steam Generator Tube Rupture
2. EOP-2.0A/B Faulted Steam Generator Isolation
3. NEI 99-01 RCS or SG Tube Leakage Containment Loss 1.A

Barrier: Containment

Category: A. RCS or SG Tube Leakage

Degradation Threat: Potential Loss

Threshold:

None

Barrier: Containment

Category: B. Inadequate heat Removal

Degradation Threat: Loss

Threshold:

None

Barrier: Containment

Category: B. Inadequate heat Removal

Degradation Threat: Potential Loss

Threshold:

1. CSFST Core Cooling-**RED** Path conditions met

   AND

   Restoration procedures **not** effective within 15 min. (Note 1)

Note 1: The Emergency Director should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Definition(s):

None

Basis:

Critical Safety Function Status Tree (CSFST) Core Cooling-RED path indicates significant core exit superheating and core uncovery. The CSFSTs are normally monitored using the SPDS display on the Plant Computer (ref. 1).

The function restoration procedures are those emergency operating procedures that address the recovery of the core cooling critical safety functions. The procedure is considered effective if the temperature is decreasing or if the vessel water level is increasing (ref. 1).

A direct correlation to status trees can be made if the effectiveness of the restoration procedures is also evaluated. If core exit thermocouple (TC) readings are greater than 1,200°F (ref. 1), Fuel Clad barrier is also lost.

This threshold addresses any other factors that may be used by the Emergency Coordinator in determining whether the RCS Barrier is potentially lost. The Emergency Director should also consider whether or not to declare the barrier potentially lost in the event that barrier status cannot be monitored.

CPNPP Basis Reference(s):

1. FRC-0.1A/B Response to Inadequate Core Cooling
2. NEI 99-01 Inadequate Heat Removal Containment Potential Loss 2.A

Barrier: Containment

Category: C. CNTMT Radiation/RCS Activity

Degradation Threat: Loss

Threshold:

None

Barrier: Containment

Category: C. CNTMT Radiation/RCS Activity

Degradation Threat: Potential Loss

Threshold:

1. Containment radiation greater than 1,110 R/hr
   CTEu16 Containment HRRM (u-RE-6290A), or
   CTWu17 Containment HRRM (u-RE-6290B)

Definition(s):

None

Basis:

Containment radiation monitor readings greater than 1,110 R/hr indicate significant fuel damage well in excess of that required for loss of the RCS barrier and the Fuel Clad barrier. Regardless of whether the Containment barrier itself is challenged, this amount of activity in containment could have severe consequences if released. It is, therefore, prudent to treat this as a Potential Loss of the Containment barrier. (ref. 2, 3)

The readings are higher than that specified for Fuel Clad Loss C.3 and RCS Loss C.1. Containment radiation readings at or above the Containment barrier Potential Loss threshold, therefore, signify a loss of two fission product barriers and Potential Loss of a third, indicating the need to upgrade the emergency classification to a General Emergency.

The analysis performed in VL-03-00032 was used to determine the potential containment loss threshold. Since the containment potential loss threshold also assumes a loss of the RCS barrier, the Figure 3A (CRM3) curve which represents the dose response at low RCS pressure with sprays present was used. The setpoint was developed on the assumption of 100% fuel rod rupture with 100% of the noble gas and 50% of the iodine and cesium in the RCS released to containment. With containment spray operating, the containment inventory of all fission products except the noble gases are reduced by a factor of 100. Per Figure 3A, the value one hour after shutdown for 100% rod rupture is 5560 R/hr; therefore, the EAL threshold at 20% fuel defects is: 5,560 R/hr *20% = 1,112 R/hr (rounded to 1,110 R/hr for instrument readability) (ref. 2, 3).

The Containment High Range Radiation Monitors (HRRMs) provide indication of radiation levels in Containment during and after postulated accidents. The monitors are two ion chamber detectors located on the 905' level of Containment approximately 90° apart. The range of each monitor is 1 to 10^8 R/hr. The output of each detector is fed to an RM-80 located outside Containment. The RM-80 provides monitoring, alarming, and recording functions for the monitor channel. The RM-80 works in conjunction with the PC-11, RM-21, and RM-23 assemblies. (ref. 1).

The radiation monitor reading corresponds to an instantaneous release of all reactor coolant mass into the containment, assuming that 20% of the fuel cladding has failed. This level of fuel clad failure is well above that used to determine the analogous Fuel Clad Barrier Loss and RCS Barrier Loss thresholds.

NUREG-1228, Source Estimations During Incident Response to Severe Nuclear Power Plant Accidents, indicates the fuel clad failure must be greater than approximately 20% in order for there to be a major release of radioactivity requiring offsite protective actions. For this condition to exist, there must already have been a loss of the RCS Barrier and the Fuel Clad Barrier. It is therefore prudent to treat this condition as a potential loss of containment which would then escalate the ECL to a General Emergency.

CPNPP Basis Reference(s):

1. DBD-EE-023 Radiation Monitoring System
2. Evaluation performed by Design Engineering & Analysis (Andrea Lemons) (AI-CR-2014-012646-15)
3. EPP-312 Core Damage Assessment
4. NEI 99-01 CNTMT Radiation / RCS Activity Containment Potential Loss 3.A

Barrier: Containment

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Loss

Threshold:

1. Containment isolation is required

   AND EITHER:

   - Containment integrity has been lost based on Emergency Coordinator judgment
   - UNISOLABLE pathway from containment to the environment exists

Definition(s):

UNISOLABLE - An open or breached system line that cannot be isolated, remotely or locally.

Basis:

These thresholds address a situation where containment isolation is required and one of two conditions exists as discussed below. Users are reminded that there may be accident and release conditions that simultaneously meet both bulleted thresholds.

<u>First Threshold</u> – Containment integrity has been lost, i.e., the actual containment atmospheric leak rate likely exceeds that associated with allowable leakage (or sometimes referred to as design leakage). Following the release of RCS mass into containment, containment pressure will fluctuate based on a variety of factors; a loss of containment integrity condition may (or may not) be accompanied by a noticeable drop in containment pressure. Recognizing the inherent difficulties in determining a containment leak rate during accident conditions, it is expected that the Emergency Coordinator will assess this threshold using judgment, and with due consideration given to current plant conditions, and available operational and radiological data (e.g., containment pressure, readings on radiation monitors outside containment, operating status of containment pressure control equipment, etc.).

Refer to the middle piping run of Figure 1. Two simplified examples are provided. One is leakage from a penetration and the other is leakage from an in-service system valve. Depending upon radiation monitor locations and sensitivities, the leakage could be detected by any of the four monitors depicted in the figure.

Another example would be a loss or potential loss of the RCS barrier, and the simultaneous occurrence of two FAULTED locations on a steam generator where one fault is located inside containment (e.g., on a steam or feedwater line) and the other outside of containment. In this case, the associated steam line provides a pathway for the containment atmosphere to escape to an area outside the containment.

Following the leakage of RCS mass into containment and a rise in containment pressure, there may be minor radiological releases associated with allowable (design) containment leakage through various penetrations or system components. These releases do not constitute a loss or potential loss of containment but should be evaluated using the Recognition Category R ICs.

Second Threshold – Conditions are such that there is an UNISOLABLE pathway for the migration of radioactive material from the containment atmosphere to the environment. As used here, the term "environment" includes the atmosphere of a room or area, outside the containment, that may, in turn, communicate with the outside-the-plant atmosphere (e.g., through discharge of a ventilation system or atmospheric leakage). Depending upon a variety of factors, this condition may or may not be accompanied by a noticeable drop in containment pressure.

Refer to the top piping run of Figure 1. In this simplified example, the inboard and outboard isolation valves remained open after a containment isolation was required (i.e., containment isolation was not successful). There is now an UNISOLABLE pathway from the containment to the environment.

The existence of a filter is not considered in the threshold assessment. Filters do not remove fission product noble gases. In addition, a filter could become ineffective due to iodine and/or particulate loading beyond design limits (i.e., retention ability has been exceeded) or water saturation from steam/high humidity in the release stream.

Leakage between two interfacing liquid systems, by itself, does not meet this threshold.

Refer to the bottom piping run of Figure 1. In this simplified example, leakage in an RCP seal cooler is allowing radioactive material to enter the Auxiliary Building. The radioactivity would be detected by the Process Monitor. If there is no leakage from the closed water cooling system to the Auxiliary Building, then no threshold has been met. If the pump developed a leak that allowed steam/water to enter the Auxiliary Building, then second threshold would be met. Depending upon radiation monitor locations and sensitivities, this leakage could be detected by any of the four monitors depicted in the figure and cause the first threshold to be met as well.

Following the leakage of RCS mass into containment and a rise in containment pressure, there may be minor radiological releases associated with allowable containment leakage through various penetrations or system components. Minor releases may also occur if a containment isolation valve(s) fails to close but the containment atmosphere escapes to an enclosed system. These releases do not constitute a loss or potential loss of containment but should be evaluated using the Recognition Category R ICs.

The status of the containment barrier during an event involving steam generator tube leakage is assessed using Loss Threshold A.1.

CPNPP Basis Reference(s):

1. NEI 99-01 CNTMT Integrity or Bypass Containment Loss 4.A

Barrier: Containment

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Loss

Threshold:

2.	Indications of RCS leakage outside of containment

Definition(s):

None

Basis:

ECA-1.2A/B LOCA Outside Containment (ref. 1) provides instructions to identify and isolate a LOCA outside of the containment. Potential RCS leak pathways outside containment include (ref. 1):

- Residual Heat Removal
- Safety Injection
- Chemical & Volume Control
- RCP seals
- PZR/RCS Loop sample lines

Containment sump, temperature, pressure and/or radiation levels will increase if reactor coolant mass is leaking into the containment. If these parameters have not increased, then the reactor coolant mass may be leaking outside of containment (i.e., a containment bypass sequence). Increases in sump, temperature, pressure, flow and/or radiation level readings outside of the containment may indicate that the RCS mass is being lost outside of containment.

Unexpected elevated readings and alarms on radiation monitors with detectors outside containment should be corroborated with other available indications to confirm that the source is a loss of RCS mass outside of containment. If the fuel clad barrier has not been lost, radiation monitor readings outside of containment may not increase significantly; however, other unexpected changes in sump levels, area temperatures or pressures, flow rates, etc. should be sufficient to determine if RCS mass is being lost outside of the containment.

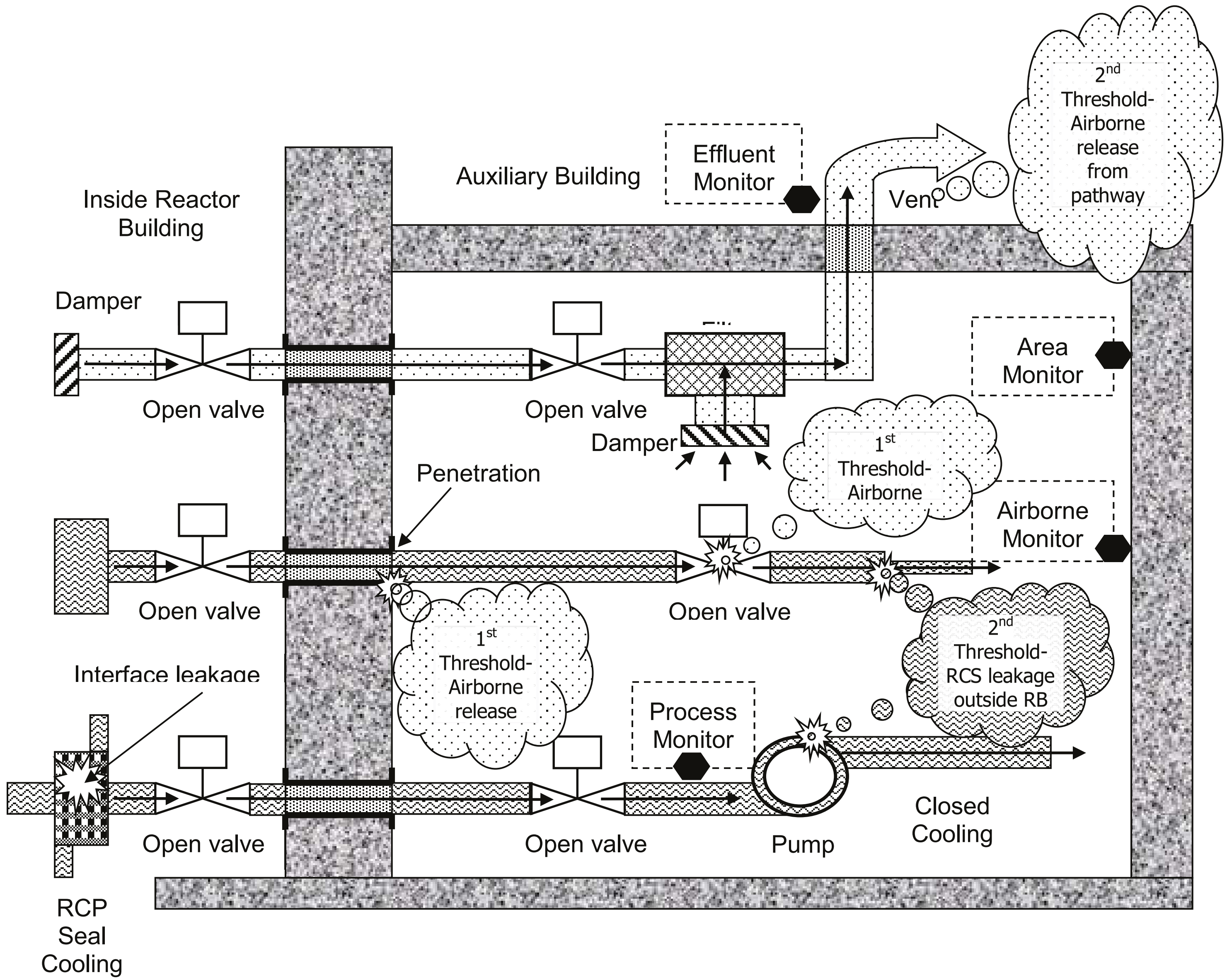
Refer to the middle piping run of Figure 1. In this simplified example, a leak has occurred at a reducer on a pipe carrying reactor coolant in the Auxiliary Building. Depending upon radiation monitor locations and sensitivities, the leakage could be detected by any of the four monitors depicted in the figure and cause threshold D.1 to be met as well.

To ensure proper escalation of the emergency classification, the RCS leakage outside of containment must be related to the mass loss that is causing the RCS Loss and/or Potential Loss threshold A.1 to be met.

CPNPP Basis Reference(s):

1. ECA-1.2A/B LOCA Outside Containment
2. NEI 99-01 CNTMT Integrity or Bypass Containment Loss

Figure 1: Containment Integrity or Bypass Examples



Barrier: Containment

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Potential Loss

Threshold:

1. CSFST Containment-**RED** Path conditions met

Definition(s):

None

Basis:

Critical Safety Function Status Tree (CSFST) Containment-RED path is entered if containment pressure is greater than or equal to 50 psig and represents an extreme challenge to safety function. The CSFSTs are normally monitored using the SPDS display on the Plant Computer (ref. 1).

50 psig is the containment design pressure and is the pressure used to define CSFST Containment Red Path conditions (ref. 2).

If containment pressure exceeds the design pressure, there exists a potential to lose the Containment Barrier. To reach this level, there must be an inadequate core cooling condition for an extended period of time; therefore, the RCS and Fuel Clad barriers would already be lost. Thus, this threshold is a discriminator between a Site Area Emergency and General Emergency since there is now a potential to lose the third barrier.

CPNPP Basis Reference(s):

1. FRC-Z.1A/B Response to High Containment Pressure
2. FSAR Table 6.2.1-1
3. NEI 99-01 CNTMT Integrity or Bypass Containment Potential Loss 4.A

Barrier: Containment

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Potential Loss

Threshold:

2. Containment hydrogen concentration greater than 4%

Definition(s):

None

Basis:

In the early stages of a core uncovery event, it is unlikely that hydrogen buildup due to a core uncovery could result in an explosive mixture of dissolved gasses in Containment. However, Containment monitoring and/or sampling should be performed to verify this assumption and a General Emergency declared if it is determined that an explosive mixture exists. A combustible mixture can be formed when hydrogen gas concentration in the Containment atmosphere is greater than 4% by volume. All hydrogen measurements are referenced to concentrations in dry air even though the actual Containment environment may contain significant steam concentrations. The plant has two hydrogen monitoring systems. Each monitoring system consists of four sensor modules and one microprocessor analyzer. Two sensors from each Containment are coupled to one of the two hydrogen microprocessors located in the Control Room. Thus each microprocessor analyzer is shared by Units 1 and 2. The analyzer system has a range of 0-10% hydrogen by volume. The detector modules are located on the 905', 873', and 860' elevations in Containment. A fourth detector is located on 832' level across from the loop room entrance for loops 1 and 4. Hydrogen concentration is displayed in the Control Room on u-AI-5506A/B and u-AI-5506C/D.

Hydrogen concentration can also be displayed on the Plant Computer. Alarms at ~3% are provided for high hydrogen concentration, u-ALB-3A, window 3.7. If a hydrogen concentration value can not be obtained from the hydrogen monitoring system, a grab sample from the containment PIG radiation monitor may be used to determine the hydrogen concentration (ref. 1, 2, 3, 4).

To generate such levels of combustible gas, loss of the Fuel Clad and RCS barriers must have occurred. With the Potential Loss of the Containment barrier, the threshold hydrogen concentration, therefore, will likely warrant declaration of a General Emergency.

The existence of an explosive mixture means, at a minimum, that the containment atmospheric hydrogen concentration is sufficient to support a hydrogen burn (i.e., at the lower deflagration limit). A hydrogen burn will raise containment pressure and could result in collateral equipment damage leading to a loss of containment integrity. It therefore represents a potential loss of the Containment Barrier.

CPNPP Basis Reference(s):

1. FRC-0.1A/B Response to Inadequate Core Cooling, Attachment 5
2. FSAR Section 6.2.5
3. FSAR Table 7.5-7A
4. CHM-111, Primary Chemistry Accident Assessment Sampling Program
7. NEI 99-01 CNTMT Integrity or Bypass Containment Potential Loss 4.B

Barrier: Containment

Category: D. CNTMT Integrity or Bypass

Degradation Threat: Potential Loss

Threshold:

3.	Containment pressure greater than 18 psig with **neither** Containment Spray system train operating per design for greater than or equal to 15 min. (Note 1)

Note 1: The Emergency Director should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded.

Definition(s):

None

Basis:

This threshold represents a Potential Loss of the Containment barrier because the Containment heat removal and depressurization equipment (but not including Containment venting strategies) is either lost or degraded. The Containment Spray System (CSS) is designed to remove heat from the Containment environment following a LOCA, a main steam line break accident, or a feedwater line break accident. Each unit of the CPNPP is equipped with two redundant Containment spray trains, each designed to provide emergency Containment heat removal in the event of a LOCA. This system, in conjunction with the ECCS, removes postaccident thermal energy from the Containment environment, thereby reducing the Containment pressure and temperature. Each train includes two containment spray pumps, spray headers, nozzles, valves, and piping. Each train is powered from a separate safeguard bus. (ref. 1)

The Containment pressure setpoint (18 psig, ref. 2) is the pressure at which the Containment Spray System should actuate and begin performing its function. The design basis accident analyses and evaluations assume the loss of one Containment Spray System train (ref. 1).

This threshold describes a condition where containment pressure is greater than the setpoint at which containment energy (heat) removal systems are designed to automatically actuate, and less than one full train of equipment is capable of operating per design. The 15-minute criterion is included to allow operators time to manually start equipment that may not have automatically started, if possible. This threshold represents a potential loss of containment in that containment heat removal/depressurization systems (e.g., containment sprays, ice condenser fans, etc., but not including containment venting strategies) are either lost or performing in a degraded manner.

CPNPP Basis Reference(s):

1. FSAR Section 6.2.2
2. FRC-Z.1A/B Response to High Containment Pressure
3. NEI 99-01 CNTMT Integrity or Bypass Containment Potential Loss 4.C

Barrier: Containment

Category: E. Emergency Coordinator Judgment

Degradation Threat: Loss

Threshold:

1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the Containment barrier

Definition(s):

None

Basis:

The Emergency Coordinator judgment threshold addresses any other factors relevant to determining if the Primary Containment barrier is lost. Such a determination should include imminent barrier degradation, barrier monitoring capability and dominant accident sequences.

- Imminent barrier degradation exists if the degradation will likely occur within relatively short period of time based on a projection of current safety system performance. The term "imminent" refers to recognition of the inability to reach safety acceptance criteria before completion of all checks.
- Barrier monitoring capability is decreased if there is a loss or lack of reliable indicators. This assessment should include instrumentation operability concerns, readings from portable instrumentation and consideration of offsite monitoring results.
- Dominant accident sequences lead to degradation of all fission product barriers and likely entry to the EOPs. The Emergency Coordinator should be mindful of the Loss of AC power (Station Blackout) and ATWS EALs to assure timely emergency classification declarations.

This threshold addresses any other factors that may be used by the Emergency Coordinator in determining whether the Containment Barrier is lost.

CPNPP Basis Reference(s):

1. NEI 99-01 Emergency Director Judgment PC Loss 6.A

Barrier: Containment

Category: E. Emergency Coordinator Judgment

Degradation Threat: Potential Loss

Threshold:

1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the Containment barrier

Definition(s):

None

Basis:

The Emergency Coordinator judgment threshold addresses any other factors relevant to determining if the Primary Containment barrier is potentially lost. Such a determination should include imminent barrier degradation, barrier monitoring capability and dominant accident sequences.

- Imminent barrier degradation exists if the degradation will likely occur within relatively short period of time based on a projection of current safety system performance. The term “imminent” refers to recognition of the inability to reach safety acceptance criteria before completion of all checks.
- Barrier monitoring capability is decreased if there is a loss or lack of reliable indicators. This assessment should include instrumentation operability concerns, readings from portable instrumentation and consideration of offsite monitoring results.
- Dominant accident sequences lead to degradation of all fission product barriers and likely entry to the EOPs. The Emergency Coordinator should be mindful of the Loss of AC power (Station Blackout) and ATWS EALs to assure timely emergency classification declarations.

This threshold addresses any other factors that may be used by the Emergency Coordinator in determining whether the Containment Barrier is lost.

CPNPP Basis Reference(s):

1. NEI 99-01 Emergency Director Judgment PC Potential Loss 6.A

Background

NEI 99-01 Revision 6 ICs AA3 and HA5 prescribe declaration of an Alert based on impeded access to rooms or areas (due to either area radiation levels or hazardous gas concentrations) where equipment necessary for normal plant operations, cooldown or shutdown is located. These areas are intended to be plant operating mode dependent. Specifically the Developers Notes for AA3 and HA5 states:

> *The "site-specific list of plant rooms or areas with entry-related mode applicability identified" should specify those rooms or areas that contain equipment which require a manual/local action as specified in operating procedures used for normal plant operation, cooldown and shutdown. Do not include rooms or areas in which actions of a contingent or emergency nature would be performed (e.g., an action to address an off-normal or emergency condition such as emergency repairs, corrective measures or emergency operations). In addition, the list should specify the plant mode(s) during which entry would be required for each room or area.*
>
> *The list should not include rooms or areas for which entry is required solely to perform actions of an administrative or record keeping nature (e.g., normal rounds or routine inspections).*

Further, as specified in IC HA5:

> *The list need not include the Control Room if adequate engineered safety/design features are in place to preclude a Control Room evacuation due to the release of a hazardous gas. Such features may include, but are not limited to, capability to draw air from multiple air intakes at different and separate locations, inner and outer atmospheric boundaries, or the capability to acquire and maintain positive pressure within the Control Room envelope.*

CPNPP Table R-3 and H-2 Bases

A review of station operating procedures identified the following mode dependent in-plant actions and associated areas that are required for normal plant operation, cooldown or shutdown:

Location- **Safe Shutdown Area**	**Modes-** **1, 2**	**Modes-** **3, 4, 5, or 6**
Charging Pump Rooms	SDC Equipment. - *No entry required* Inventory Control Equipment -**Entry required during pump starts and stops**	Shut Down Cooling (SDC) **-** *No entry required* Inventory Control Equipment - **Entry required during pump starts and stops** Reactivity Control. - **Entry required during pump starts and stops**
-Containment Spray Pumps A and B	Post-accident Containment Pressure Control - *No entry required*	Post-accident Containment Pressure Control (modes 3 and 4) - *No entry required*
-SI Pumps A and B	Post-accident ECCS - *No entry required*	Post-accident ECCS - *No entry required*
-Residual Heat Removal Pumps A and B	Post-accident ECCS - *No entry required*	Decay Heat Removal (Modes 4, 5, and 6 - **Entry required for pumps starts and stops**
- CVCS Valve Rooms, Auxiliary Building 810' and 822'	Inventory Control Equipment - **Entry required during pump starts and stops** Reactivity Control. - **Entry required during pump starts and stops**	Inventory Control Equipment - **Entry required during pump starts and stops** Reactivity Control. - **Entry required during pump starts and stops**
-Service Water Intake Structure	Ultimate Heat Sink Equipment for Habitability Control, Containment Temperature, and Shutdown Cooling - *No entry required*	Ultimate Heat Sink Equipment for Habitability Control, Containment Temperature, and Shutdown Cooling *No entry required*
1E Switchgear Rooms 810', 832', and 852'	Electrical Power. - **Entry required for manual breaker manipulations on component operations, reactor startup and shutdown**	Electrical Power. - **Entry required for manual breaker manipulations on component operations**
Control Building 807'Cable Spreading Room	Electrical Power. - *No entry required*	Electrical Power. - *No entry required*
Control Building 792' UPS and Battery Rooms	Electrical Power. - *No entry required*	Electrical Power. -
Emergency Diesel Generators A & B	Electrical Power. - *No entry required*	Electrical Power. - *No entry required*
Emergency Diesel Generators Day Tank Rooms	Electrical Power. - *No entry required*	Electrical Power. - *No entry required*
Control Building 830' Control Room	- *Continuously occupied, capable of Ventilation Isolation mode, covered under H-6*	- *Continuously occupied, capable of Ventilation Isolation mode, covered under H-6*

ATTACHMENT 3

Safe Operation & Shutdown Areas Tables R-3 & H-2 Bases

Location- Safe Shutdown Area	**Modes- 1, 2**	**Modes- 3, 4, 5, or 6**
Control Building 840' Technical Support Center	- *No entry required*	- *No entry required*
Control Building 778' Safety Chiller Rooms	- *No entry required*	- *No entry required*
Auxiliary Building 790'	- *No entry required*	- *No entry required*
Auxiliary Building 810' other than CVCS Valave Rooms and Charging Pump Rooms	- *No entry required*	- *No entry required*
Auxiliary Building 830'	- *No entry required*	- *No entry required*
Auxiliary Building 852'	- *No entry required*	- *No entry required*
Auxiliary Building 873'	- *No entry required*	- *No entry required*
Auxiliary Building 886'	- *No entry required*	- *No entry required*
Safeguards 790'	- *No entry required*	- *No entry required*
Safeguards 810'	- *No entry required*	- *No entry required*
Safeguards 831'	- *No entry required*	- *No entry required*
Safeguards 852'	- *No entry required*	- *No entry required*
Safeguards 873'	- *No entry required*	- *No entry required*
Turbine Building Elevations	- *No entry required*	- *No entry required*
Aux. Feedwater Pump Rooms A, B, and Turbine Driven	Steam Generator Heat Removal - *No entry required*	Steam Generator Heat Removal - *No entry required*

Table R-3 & H-2 Results

Table R-3/H-2 Safe Operation & Shutdown Rooms/Areas	
Room/Area	**Mode Applicability**
Charging Pump Rooms	1, 2, 3, 4, 5, 6
CVCS Valve Rooms	1, 2, 3, 4, 5, 6
1E Switchgear Rooms	All
RHR Pump Rooms	4, 5, 6

Plant Operating Procedures Reviewed

1. IPO-003A/B
2. IPO-005A/B
3. IPO-001A/B
4. IPO-002A/B
5. SOP-103
6. SOP-104
7. SOP-102

Record of Changes (For Information Only)		
Rev / PCN	Affected Pages	Description of Change
1	All	Major Revision – EAL scheme changed to NEI 99-01 Revision 6.

COMANCHE PEAK NUCLEAR POWER PLANT

EMERGENCY PLAN MANUAL

**LEVEL OF USE:
INFORMATION USE**

NOTIFICATIONS

PROCEDURE NO. EPP-203

REVISION NO. 16

EFFECTIVE DATE: 11-4-10 12:00

ELECTRONIC CONTROLLED COPY

CHANGES ARE NOT INDICATED

LATEST CHANGE NOTICE EFFECTIVE DATE ________________ /_____________

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PREPARED BY: (Print): Ted Robison EXT: 5476

TECHNICAL REVIEW BY (Print) Gary Wiechering EXT: 0180

APPROVED BY: David W. Fuller DATE: 27-Oct-2010

EMERGENCY PLANNING MANAGER

1.0 PURPOSE

This procedure describes the initial notifications to be made to Comanche Peak Nuclear Plant (CPNPP) employees, CPNPP Emergency Response Organization (ERO) members, Hood County, Somervell County, Department of Public Safety (DPS), certain state and federal agencies upon declaration of an emergency classification.

This procedure also describes follow-up notifications to periodically status an on-going emergency at CPNPP.

2.0 APPLICABILITY

This procedure becomes effective upon declaration of an Unusual Event (UE) or higher emergency classification.

This procedure is applicable to the following CPNPP Emergency Response Organization positions:

Shift Manager
Control Room Communicator
TSC Manager
TSC Communications Coordinator
TSC Communicator
TSC ENS Communicator
EOF HPN Communicator
EOF Manager
EOF Communications Coordinator
EOF Communicator

3.0 DEFINITIONS

3.1 Emergency Notification System (ENS) – a Federal Telephone System circuit between NRC Operations Center and nuclear power stations for passing reactor safety information.

3.2 Health Physics Network (HPN) – a Federal Telephone System circuit between NRC Operations Center and nuclear power stations for passing radiological information.

4.0 INSTRUCTIONS

4.1 General Information [C-05708]

4.1.1 Following declaration of any emergency classification, identify at least one Plant Page Party System line to transmit information during the emergency.

4.1.2 Notify Somervell County, Hood County, and DPS of any emergency at CPNPP using the dedicated ring-down telephone system.

4.1.2.1 Notification shall be made **within 15 minutes** if any of the following conditions occur:

- Initial emergency classification;
- Escalation of emergency classification;
- Initial protective action recommendation (PAR);
- Change in protective action recommendation (PAR); or
- Termination of the emergency.

4.1.2.2 As a minimum, notify the offsite agencies every hour unless otherwise directed by the individual agency.

4.1.3 Notify CPNPP personnel of any emergency at CPNPP by the Plant Page Party System, Call-out system, or pager activation.

4.1.3.1 Contact the CPNPP personnel on site by the Plant Page Party System at all times.

4.1.3.2 Contact the ERO members not on site using the Call-out system.

4.1.3.3 Contact key ERO members by pager activation at all times.

4.1.3.4 Squaw Creek Park receives notification when the pager activation occurs. [C-05740]

4.1.4 Notify an NRC resident inspector of any emergency at CPNPP through the site NRC office or by pager.

4.1.5 Notify the NRC Operations Center of any emergency at CPNPP by using the Emergency Notification System (ENS).

4.1.5.1 The Center should be contacted **immediately after** the notification to local agencies, state agencies, plant personnel and ERO personnel, **not to exceed one hour from the initial declaration of an emergency**.

4.1.5.2 For a security related imminent threat or attack against the station, the notification should be immediate with a goal to initiate the call within approximately 15 minutes.

4.1.5.3 Once contacted, the NRC duty officer may request continuous communications. If so, a person knowledgeable of CPNPP plant operations shall be required to remain on the ENS line throughout the emergency.

4.1.5.4 During the event, the NRC Operations Center shall be immediately notified of any further degradation in the level of safety, worsening plant conditions, escalation of the emergency classification, or termination of the emergency. [C-05429]

4.1.6 Other Notifications and Interfaces

4.1.6.1 Notify the Environmental Protection Agency (EPA) National Response Center whenever an environmental radioactive material release greater than allowable limit occurs.

4.1.6.2 Immediately following notification to the EPA, notify the Manager, Radiation Protection or his designee, of the environmental release and notification.

4.1.6.3 The Department of State Health Services (DSHS) in Austin is initially notified of an emergency classification at CPNPP via DPS and by fax.

4.1.6.4 At an emergency classification of ALERT or higher and upon their request, the DSHS is kept advised of emergency conditions at CPNPP by the EOF Offsite Radiological Assessment Coordinator (OffRAC). [C-08096]

4.1.7 Form EPP-203-8, “Notification Message Form,” identifies information required for the initial notification and follow-up notifications.

4.1.8 Instructions for completing form EPP-203-8 are given in the Communicator Position Assistance Document (PAD).

4.1.9 Following completion of form EPP-203-8, have the Emergency Coordinator review and approve it ***before*** any information is transmitted to anyone.

4.1.10 Transmit information on the approved form EPP-203-8 to Hood County, Somervell County, and DPS, in accordance with the Communicator PAD.

4.1.11 Expect a confirmation call from DPS to verify the authenticity of the ***initial notification***.

4.1.12 Responsibility for notifications should be transferred from the Control Room to the Technical Support Center (TSC) upon declaration of an ALERT or higher emergency classification.

4.1.13 Responsibility for notifications should be transferred from the TSC to the Emergency Operations Facility (EOF) when the EOF is staffed and activated.

5.0 REFERENCES

5.1.1 Code of Federal Regulations: 10 CFR 50, Appendix E, Section D.3; 10 CFR 50.72 and 10 CFR 50.47b

5.1.2 NUREG-0654, FEMA-REP-1, Rev. 1, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants”

5.1.3 Comanche Peak Nuclear Power Plant (CPNPP) Emergency Plan

5.1.4 ABN-915 (Abnormal Conditions Procedure Manual), “Security Events”

6.0 ATTACHMENTS/FORMS

6.1 Attachments

NONE

6.2 Forms

6.2.1 EPP-203-8, “Notification Message Form”

GENERAL EMERGENCY | SITE AREA EMERGENCY | ALERT | UNUSUAL EVENT

R — Abnormal Rad Levels / Rad Effluent

1 Rad Effluent

General Emergency — Release of gaseous radioactivity resulting in offsite dose greater than 1,000 mrem TEDE or 5,000 mrem thyroid CDE

RG1.1 1 2 3 4 5 6 DEF
Reading on **any** Table R-1 effluent radiation monitor greater than column "GE" for greater than or equal to 15 min. (Notes 1, 2, 3, 4) [46]

RG1.2 1 2 3 4 5 6 DEF
Dose assessment using actual meteorology indicates doses greater than` 1000 mrem TEDE or 5000 mrem thyroid CDE at or beyond the EXCLUSION AREA BOUNDARY (Note 4) [48]

RG1.3 1 2 3 4 5 6 DEF
Field survey results indicate **EITHER** of the following at or beyond the EXCLUSION AREA BOUNDARY:
- Closed window dose rates greater than 1000 mR/hr expected to continue for greater than or equal to 60 min.
- Analyses of field survey samples indicate thyroid CDE greater than 5000 mrem for 60 min. of inhalation.

(Notes 1, 2) [50]

Site Area Emergency — Release of gaseous radioactivity resulting in offsite dose greater than 100 mrem TEDE or 500 mrem thyroid CDE

RS1.1 1 2 3 4 5 6 DEF
Reading on **any** Table R-1 effluent radiation monitor greater than column "SAE" for greater than or equal to 15 min. (Notes 1, 2, 3, 4) [40]

RS1.2 1 2 3 4 5 6 DEF
Dose assessment using actual meteorology indicates doses greater than 100 mrem TEDE or 500 mrem thyroid CDE at or beyond the EXCLUSION AREA BOUNDARY (Note 4) [42]

RS1.3 1 2 3 4 5 6 DEF
Field survey results indicate **EITHER** of the following at or beyond the EXCLUSION AREA BOUNDARY:
- Closed window dose rates greater than 100 mR/hr expected to continue for greater than or equal to 60 min.
- Analyses of field survey samples indicate thyroid CDE greater than 500 mrem for 60 min. of inhalation.

(Notes 1, 2) [44]

Alert — Release of gaseous or liquid radioactivity resulting in offsite dose greater than 10 mrem TEDE or 50 mrem thyroid CDE

RA1.1 1 2 3 4 5 6 DEF
Reading on **any** Table R-1 effluent radiation monitor greater than column "ALERT" for greater than or equal to 15 min. (Notes 1, 2, 3, 4) [32]

RA1.2 1 2 3 4 5 6 DEF
Dose assessment using actual meteorology indicates doses greater than 10 mrem TEDE or 50 mrem thyroid CDE at or beyond the EXCLUSION AREA BOUNDARY (Note 4) [34]

RA1.3 1 2 3 4 5 6 DEF
Analysis of a liquid effluent sample indicates a concentration or release rate that would result in doses greater than 10 mrem TEDE or 50 mrem thyroid CDE at or beyond the EXCLUSION AREA BOUNDARY for 60 min. of exposure (Notes 1, 2) [36]

RA1.4 1 2 3 4 5 6 DEF
Field survey results indicate **EITHER** of the following at or beyond the EXCLUSION AREA BOUNDARY:
- Closed window dose rates greater than 10 mR/hr expected to continue for greater than or equal to 60 min.
- Analyses of field survey samples indicate thyroid CDE greater than 50 mrem for 60 min. of inhalation.

(Notes 1, 2) [38]

Unusual Event — Release of gaseous or liquid radioactivity greater than 2 times the ODCM limits for 60 minutes or longer

RU1.1 1 2 3 4 5 6 DEF
Reading on **any** Table R-1 effluent radiation monitor greater than column "UE" for greater than or equal to 60 min. (Notes 1, 2, 3) [27]

RU1.2 1 2 3 4 5 6 DEF
Sample analyses for a gaseous or liquid release indicates a concentration or release rate greater than 2 x ODCM limits for greater than or equal to 60 min. (Notes 1, 2) [30]

2 Irradiated Fuel Event

General Emergency — Spent fuel pool level cannot be restored to at least the top of the fuel racks for 60 minutes or longer

RG2.1 1 2 3 4 5 6 DEF
Spent fuel pool level cannot be restored to at least 835.3' (Level 3) for greater than or equal to 60 min. (Note 1) [62]

Site Area Emergency — Spent fuel pool level at the top of the fuel racks

RS2.1 1 2 3 4 5 6 DEF
Lowering of spent fuel pool level to 835.3' (Level 3) [60]

Alert — Significant lowering of water level above, or damage to, irradiated fuel

RA2.1 1 2 3 4 5 6 DEF
Uncovery of irradiated fuel in the REFUELING PATHWAY [55]

RA2.2 1 2 3 4 5 6 DEF
Damage to irradiated fuel resulting in a release of radioactivity
AND
High alarm on **any** of the following: [56]
- **Any** Table R-2 area radiation monitors
- CAGu97, CNTMT AIR PIG GAS (u-RE-5503)
- CAPu98, CNTMT AIR PIG PART (u-RE-5502)
- CAIu99, CNTMT AIR PIG IODINE (u-RE-5566)
- FBV088, FB VENT EXH (X-RE-5700)

RA2.3 1 2 3 4 5 6 DEF
Lowering of spent fuel pool level to El. 844.3' (Level 2) [58]

Unusual Event — Unplanned loss of water level above irradiated fuel

RU2.1 1 2 3 4 5 6 DEF
UNPLANNED water level drop in the REFUELING PATHWAY as indicated by **any** low water level alarm or indication, Table R-4
AND
UNPLANNED rise in corresponding area radiation levels as indicated by **any** Table R-2 radiation monitors [52]

Table R-1 Effluent Monitor Classification Thresholds

	Release Point	Monitor	GE	SAE	Alert	UE
Gaseous	**Plant Vent (WRGM)** PVF684 + PVF685	X-RE-5570 A + B	3.0E+7 µCi/sec	3.0E+6 µCi/sec	3.0E+5 µCi/sec	4.0E+4 µCi/sec
Gaseous	**Main Steam** MSLu78 MSLu79 MSLu80 MSLu81	u-RE-2325 u-RE-2326 u-RE-2327 u-RE-2328	97 µCi/ml *	9.7 µCi/ml *	0.97 µCi/ml *	2 X high alarm setpoint *
Liquid	**Liquid Waste** LWE-076	X-RE-5253	-----	-----	-----	2 X high alarm setpoint
Liquid	**Service Water** SSWu65 SSWu66	u-RE-4269 u-RE-4270	-----	-----	-----	2 X high alarm setpoint

* with the reactor shutdown

Table R-4 Refueling Pathway Low Level Alarms & Indications

Alarms:
- RFL CAVITY 1(2) LEVEL LO (upender area)
- SFP 1(2) LEVEL LO
- RFL CAVITY 1(2) LEVEL LO
- SFP 1(2) TRANSFER CANAL LEVEL LO

Indications:
- Plant Computer
- Visual Observation

3 Area Radiation Levels

Alert — Radiation levels that IMPEDE access to equipment necessary for normal plant operations, cooldown or shutdown

RA3.1 1 2 3 4 5 6 DEF
Dose rate greater than 15 mR/hr in **EITHER** of the following areas [64]:
- Control Room
  CRM048 (X-RE-6281) or CRM049 (X-RE-6282)
- Central Alarm Station (by survey)

RA3.2 1 2 3 4 5 6 DEF
An UNPLANNED event results in radiation levels that prohibit or IMPEDE access to **any** Table R-3 area (Note 5) [65]

Table R-2 SFP & Refueling Cavity Area Radiation Monitors

SFP:
- SFP001, LRAM SFP 2 E WALL (X-RE-6272)
- SFP002, LRAM SFP 2 N WALL (X-RE-6273)
- SFP003, LRAM SFP 1 E WALL (X-RE-6274)
- SFP004, LRAM SFP 1 S WALL (X-RE-6275)

Refueling Cavity:
- RFCu10, LRAM W REFUEL CAV860 (u-RE-6251)
- RFCu12, LRAM E REFUEL CAV860 (u-RE-6253)

Table R-3 Safe Operation & Shutdown Room/Areas

Room/Area	Mode Applicability
Charging Pump Rooms	1, 2, 3, 4, 5, 6
CVCS Valve Rooms	1, 2, 3, 4, 5, 6
1E Switchgear Rooms	All
RHR Pump Rooms	4, 5, 6

E — ISFSI

1 Confinement Boundary

Alert: None

Unusual Event — Damage to a loaded cask CONFINEMENT BOUNDARY

EU1.1 1 2 3 4 5 6 DEF
Damage to a loaded cask CONFINEMENT BOUNDARY as indicated by an on-contact radiation reading greater than **EITHER** [68]:
- 60 mrem/hr (γ + η) on the top of the overpack
- 600 mrem/hr (γ + η) on the side of the overpack (excluding inlet and outlet ducts)

H — Hazards

1 Security

General Emergency — HOSTILE ACTION resulting in loss of physical control of the facility

HG1.1 1 2 3 4 5 6 DEF
A HOSTILE ACTION is occurring or has occurred within the PROTECTED AREA as reported by the Security Shift Supervisor
AND EITHER of the following has occurred [127]:
- One or more of the following safety functions cannot be controlled or maintained
  - Reactivity control
  - Core cooling
  - RCS heat removal

OR
- Damage to spent fuel has occurred or is IMMINENT

Site Area Emergency — HOSTILE ACTION within the PROTECTED AREA

HS1.1 1 2 3 4 5 6 DEF
A HOSTILE ACTION is occurring or has occurred within the PROTECTED AREA as reported by the Security Shift Supervisor [125]

Alert — HOSTILE ACTION within the OWNER CONTROLLED AREA or airborne attack threat within 30 minutes

HA1.1 1 2 3 4 5 6 DEF
A HOSTILE ACTION is occurring or has occurred within the OWNER CONTROLLED AREA as reported by the Security Shift Supervisor [121]

HA1.2 1 2 3 4 5 6 DEF
A validated notification from NRC of an aircraft attack threat within 30 min. of the site [123]

Unusual Event — Confirmed SECURITY CONDITION or threat

HU1.1 1 2 3 4 5 6 DEF
A SECURITY CONDITION that does **not** involve a HOSTILE ACTION as reported by the Security Shift Supervisor [116]

HU1.2 1 2 3 4 5 6 DEF
Notification of a credible security threat directed at the site [118]

HU1.3 1 2 3 4 5 6 DEF
A validated notification from the NRC providing information of an aircraft threat [120]

2 Seismic Event

General Emergency: None

Site Area Emergency: None

Alert: [Refer to EAL CA6.1 OR SA9.1 for escalation due to seismic event] None

Unusual Event — Seismic event greater than OBE level

HU2.1 1 2 3 4 5 6 DEF
Seismic event greater than OBE as indicated by annunciator 2A-3.1, OBE EXCEEDED, or yellow OBE light on Seismic Monitoring system panel [129]

3 Natural or Tech. Hazard

Site Area Emergency: None

Alert: [Refer to EAL CA6.1 OR SA9.1 for escalation due to natural or technological event] None

Unusual Event — Hazardous event

HU3.1 1 2 3 4 5 6 DEF
A tornado strike within the PROTECTED AREA [131]

HU3.2 1 2 3 4 5 6 DEF
Internal room or area FLOODING of a magnitude sufficient to require manual or automatic electrical isolation of a SAFETY SYSTEM component needed for the current operating mode [132]

HU3.3 1 2 3 4 5 6 DEF
Movement of personnel within the PROTECTED AREA is IMPEDED due to an offsite event involving hazardous materials (e.g., an offsite chemical spill or toxic gas release) [134]

HU3.4 1 2 3 4 5 6 DEF
A hazardous event that results in on-site conditions sufficient to prohibit the plant staff from accessing the site via personal vehicles (Note 7) [135]

Notes

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded

Note 2: If an ongoing release is detected and the release start time is unknown, assume that the release duration has exceeded the specified time limit

Note 3: If the effluent flow past an effluent monitor is known to have stopped, indicating that the release path is isolated, the effluent monitor reading is no longer VALID for classification purposes

Note 4: The pre-calculated effluent monitor values presented in EALs RA1.1, RS1.1 and RG1.1 should be used for emergency classification assessments until the results from a dose assessment using actual meteorology are available

Note 5: If the equipment in the listed room or area was already inoperable or out-of-service before the event occurred, then no emergency classification is warranted

Note 6: If CONTAINMENT CLOSURE is re-established prior to exceeding the 30-minute time limit, declaration of a General Emergency is not required

Note 7: This EAL does not apply to routine traffic impediments such as fog, snow, ice, or vehicle breakdowns or accidents

Note 8: A manual trip action is any operator action, or set of actions, which causes the control rods to be rapidly inserted into the core, and **does not** include manually driving in control rods or implementation of boron injection strategies

Note 9: Begin monitoring hot condition EALs concurrently

4 Fire

Site Area Emergency: None

Alert: [Refer to EAL CA6.1 OR SA9.1 for escalation due to fire]

Table H-1 Fire Areas
- u-Containment
- u-Safeguards Building
- X-Auxiliary Building
- X-Electrical & Control Building
- X-Fuel Building
- X-Service Water Intake Structure
- u-Diesel Generator Building
- u-Normal Switchgear Rooms
- u-CST
- u-RWST

Unusual Event — FIRE potentially degrading the level of safety of the plant

HU4.1 1 2 3 4 5 6 DEF
A FIRE is **not** extinguished within 15 min. of **any** of the following FIRE detection indications (Note 1):
- Report from the field (i.e., visual observation)
- Receipt of multiple (more than 1) fire alarms or indications
- Field verification of a single fire alarm

AND
The FIRE is located within **any** Table H-1 area [136]

HU4.2 1 2 3 4 5 6 DEF
Receipt of a single fire alarm (i.e., **no** other indications of a FIRE)
AND
The fire alarm is indicating a FIRE within **any** Table H-1 area
AND
The existence of a FIRE is **not** verified within 30 min. of alarm receipt (Note 1) [138]

HU4.3 1 2 3 4 5 6 DEF
A FIRE within the ISFSI or plant PROTECTED AREA **not** extinguished within 60 min. of the initial report, alarm or indication (Note 1) [141]

HU4.4 1 2 3 4 5 6 DEF
A FIRE within the ISFSI or plant PROTECTED AREA that requires firefighting support by an offsite fire response agency to extinguish [142]

5 Hazardous Gases

Alert — Gaseous release IMPEDING access to equipment necessary for normal plant operations, cooldown or shutdown

HA5.1 1 2 3 4 5 6 DEF
Release of a toxic, corrosive, asphyxiant or flammable gas into **any** Table H-2 rooms or areas
AND
Entry into the room or area is prohibited or IMPEDED (Note 5) [143]

Table H-2 Safe Operation & Shutdown Room/Areas

Room/Area	Mode Applicability
Charging Pump Rooms	1, 2, 3, 4, 5, 6
CVCS Valve Rooms	1, 2, 3, 4, 5, 6
1E Switchgear Rooms	All
RHR Pump Rooms	4, 5, 6

6 Control Room Evacuation

General Emergency: None

Site Area Emergency — Inability to control a key safety function from outside the Control Room

HS6.1 1 2 3 4 5 6 DEF
An event has resulted in plant control being transferred from the Control Room to the Remote Shutdown Panel (RSP)
AND
Control of **any** of the following key safety functions is not reestablished within 15 min. (Note 1) [147]:
- Reactivity
- Core cooling
- RCS heat removal

Alert — Control Room evacuation resulting in transfer of plant control to alternate locations

HA6.1 1 2 3 4 5 6 DEF
An event has resulted in plant control being transferred from the Control Room to the Remote Shutdown Panel (RSP) [145]

Unusual Event: None

7 EC Judgment

General Emergency — Other conditions existing that in the judgment of the Emergency Coordinator warrant declaration of General Emergency

HG7.1 1 2 3 4 5 6 DEF
Other conditions exist which in the judgment of the Emergency Coordinator indicate that events are in progress or have occurred which involve actual or IMMINENT substantial core degradation or melting with potential for loss of containment integrity or HOSTILE ACTION that results in an actual loss of physical control of the facility. Releases can be reasonably expected to exceed EPA Protective Action Guideline exposure levels offsite for more than the immediate site area. [155]

Site Area Emergency — Other conditions existing that in the judgment of the Emergency Coordinator warrant declaration of Site Area Emergency

HS7.1 1 2 3 4 5 6 DEF
Other conditions exist which in the judgment of the Emergency Coordinator indicate that events are in progress or have occurred which involve actual or likely major failures of plant functions needed for protection of the public or HOSTILE ACTION that results in intentional damage or malicious acts, (1) toward site personnel or equipment that could lead to the likely failure of or, (2) that prevent effective access to equipment needed for the protection of the public. Any releases are not expected to result in exposure levels which exceed EPA Protective Action Guideline exposure levels beyond the EXCLUSION AREA BOUNDARY. [153]

Alert — Other conditions existing that in the judgment of the Emergency Coordinator warrant declaration of an Alert

HA7.1 1 2 3 4 5 6 DEF
Other conditions exist which, in the judgment of the Emergency Coordinator, indicate that events are in progress or have occurred which involve an actual or potential substantial degradation of the level of safety of the plant or a security event that involves probable life threatening risk to site personnel or damage to site equipment because of HOSTILE ACTION. Any releases are expected to be limited to small fractions of the EPA Protective Action Guideline exposure levels. [151]

Unusual Event — Other conditions existing that in the judgment of the Emergency Coordinator warrant declaration of a UE

HU7.1 1 2 3 4 5 6 DEF
Other conditions exist which in the judgment of the Emergency Coordinator indicate that events are in progress or have occurred which indicate a potential degradation of the level of safety of the plant or indicate a security threat to facility protection has been initiated. No releases of radioactive material requiring offsite response or monitoring are expected unless further degradation of SAFETY SYSTEMS occurs [149]

Modes:

1	2	3	4	5	6	DEF
Power Operation	Startup	Hot Standby	Hot Shutdown	Cold Shutdown	Refueling	Defueled

Luminant

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Prepared for Luminant by: Operations Support Services, Inc. – 12/22/16

		GENERAL EMERGENCY	SITE AREA EMERGENCY	ALERT	UNUSUAL EVENT
S System Malfunct.	**1** Loss of Emergency AC Power	Prolonged loss of **all** offsite and **all** onsite AC power to safeguard buses **SG1.1** 1 2 3 4 Loss of **all** offsite and **all** onsite AC power capability to 6.9 KV safeguard buses uEA1 and uEA2 [166] **AND EITHER:** • Restoration of at least one safeguard bus in less than 4 hours is **not** likely (Note 1) • CSFST Core Cooling-**RED** Path conditions met	Loss of **all** offsite and **all** onsite AC power to safeguard buses for 15 minutes or longer **SS1.1** 1 2 3 4 Loss of **all** offsite and **all** onsite AC power capability to 6.9 KV safeguard buses uEA1 and uEA2 for greater than or equal to 15 min. (Note 1) [164]	Loss of **all but one** AC power source to safeguard buses for 15 minutes or longer **SA1.1** 1 2 3 4 AC power capability, Table S-1, to 6.9 KV safeguard buses uEA1 and uEA2 reduced to a single power source for greater than or equal to 15 min. (Note 1) **AND** **Any** additional single power source failure will result in loss of **all** AC power to SAFETY SYSTEMS [161]	Loss of **all** offsite AC power capability to safeguard buses for 15 minutes or longer **SU1.1** 1 2 3 4 Loss of **all** offsite AC power capability, Table S-1, to 6.9 KV safeguard buses uEA1 and uEA2 for greater than or equal to 15 min. (Note 1) [159]
	2 Loss of Vital DC Power	Loss of **all** AC and vital DC power sources for 15 minutes or longer **SG1.2** 1 2 3 4 Loss of **all** offsite and **all** onsite AC power capability to 6.9 KV safeguard buses uEA1 and uEA2 for greater than or equal to 15 min. **AND** Less than 105 VDC on **all** 125 VDC safeguard buses uED1, uED2, uED3 and uED4 for greater than or equal to 15 min. (Note 1) [169]	Loss of **all** vital DC power for 15 minutes or longer **SS2.1** 1 2 3 4 Less than 105 VDC on **all** 125 VDC safeguard buses uED1, uED2, uED3 and uED4 for greater than or equal to 15 min. (Note 1) [171]	None	None
	3 Loss of Control Room Indications	None	(Table S-2)	UNPLANNED loss of Control Room indications for 15 minutes or longer with a significant transient in progress **SA3.1** 1 2 3 4 An UNPLANNED event results in the inability to monitor one or more Table S-2 parameters from within the Control Room for greater than or equal to 15 min. (Note 1) **AND** **Any** significant transient is in progress, Table S-3 [175]	UNPLANNED loss of Control Room indications for 15 minutes or longer **SU3.1** 1 2 3 4 An UNPLANNED event results in the inability to monitor one or more Table S-2 parameters from within the Control Room for greater than or equal to 15 min. (Note 1) [173]
	4 RCS Activity	None	(Table S-3)	None	Reactor coolant activity greater than Technical Specification allowable limits **SU4.1** 1 2 3 4 Reactor coolant Dose Equivalent I-131 specific activity greater than 60 µCi/gm **OR** Reactor coolant Dose Equivalent XE-133 specific activity greater than 500 µCi/gm [178] **SU4.2** 1 2 3 4 Gross Failed Fuel Monitor, FFLu60 (u-RE-0406), High Alarm (RED) [179]
	5 RCS Leakage	None	None	None	RCS leakage for 15 minutes or longer **SU5.1** 1 2 3 4 RCS unidentified or pressure boundary leakage greater than 10 gpm for greater than or equal to 15 min. **OR** RCS identified leakage greater than 25 gpm for greater than or equal to 15 min. **OR** UNISOLABLE leakage from the RCS to a location outside containment greater than 25 gpm for greater than or equal to 15 min. (Note 1) [181]
	6 RPS Failure	None	Inability to shut down the reactor causing a challenge to core cooling or RCS heat removal **SS6.1** 1 An automatic or manual trip fails to shut down the reactor as indicated by reactor power greater than 5% **AND** **All** actions to shut down the reactor are **not** successful as indicated by reactor power greater than 5% **AND EITHER** [192]: • CSFST Core Cooling-**RED** Path conditions met • CSFST Heat Sink-**RED** Path conditions met	Automatic or manual trip fails to shut down the reactor and subsequent manual actions taken at the reactor control consoles are not successful in shutting down the reactor **SA6.1** 1 An automatic or manual trip fails to shut down the reactor as indicated by reactor power greater than 5% **AND** Manual trip actions taken at the reactor control console (MCB reactor trip switches or deenergizing uB3 and uB4) are **not** successful in shutting down the reactor as indicated by reactor power greater than 5% (Note 8) [190]	Automatic or manual trip fails to shut down the reactor **SU6.1** 1 An automatic trip did **not** shut down the reactor as indicated by reactor power greater than 5% after **any** RPS setpoint is exceeded **AND** A subsequent automatic trip or manual trip action taken at the reactor control consoles (MCB reactor trip switches or deenergizing uB3 and uB4) is successful in shutting down the reactor as indicated by reactor power less than or equal to 5% (Note 8) [184] **SU6.2** 1 A manual trip did **not** shut down the reactor as indicated by reactor power greater than 5% after **any** manual trip action was initiated **AND** A subsequent automatic trip or manual trip action taken at the reactor control console (MCB reactor trip switches or deenergizing uB3 and uB4) is successful in shutting down the reactor as indicated by reactor power less than or equal to 5% (Note 8) [187]
	7 Loss of Comm.	(Notes)	None	(Table S-4)	Loss of all onsite or offsite communications capabilities **SU7.1** 1 2 3 4 Loss of **all** Table S-4 onsite communication methods **OR** Loss of **all** Table S-4 offsite communication methods **OR** Loss of **all** Table S-4 NRC communication methods [194]
	8 CMT Failure	None	None	None	Failure to isolate containment or loss of containment pressure control **SU8.1** 1 2 3 4 **Any** penetration is not isolated within 15 min. of a VALID containment isolation signal **OR** Containment pressure greater than 18 psig with **neither** Containment Spray system operating per design for greater than or equal to 15 min. (Note 1) [196]
	9 Hazardous Event Affecting Safety Systems	None	(Table S-5)	Hazardous event affecting a SAFETY SYSTEM needed for the current operating mode **SA9.1** 1 2 3 4 The occurrence of **any** Table S-5 hazardous event **AND EITHER** [198]: • Event damage has caused indications of degraded performance in at least one train of a SAFETY SYSTEM needed for the current operating mode • The event has caused VISIBLE DAMAGE to a SAFETY SYSTEM component or structure needed for the current operating mode	None
F Fission Product Barrier Degradation		**FG1.1** 1 2 3 4 Loss of **any** two barriers **AND** Loss or potential loss of third barrier (Table F-1) [205]	**FS1.1** 1 2 3 4 Loss or potential loss of **any** two barriers (Table F-1) [204]	**FA1.1** 1 2 3 4 **Any** loss or **any** potential loss of either Fuel Clad or RCS (Table F-1) [203]	None

Table S-1 AC Power Sources

Offsite:
- 138 KV switchyard circuit
- 345 KV switchyard circuit

Onsite:
- uEG1
- uEG2

Table S-2 Safety System Parameters
- Reactor power
- RCS level
- RCS pressure
- Core Exit T/C temperature
- Level in at least one SG
- Auxiliary or emergency feed flow in at least one SG

Table S-3 Significant Transients
- Reactor trip
- Runback greater than or equal to 25% thermal power
- Electrical load rejection greater than 25% electrical load
- ECCS actuation

Notes

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded

Note 8: A manual action is any operator action, or set of actions, which causes the control rods to be rapidly inserted into the core, and **does not** include manually driving in control rods or implementation of boron injection strategies

Table S-4 Communication Methods

System	Onsite	Offsite	NRC
Gai-tronics Page/Party (PA)	X		
Plant Radios	X		
Intra-Plant Phone Sustem (ITS)	X	X	X
Public Telephone	X	X	X
Federal Telephone System (FTS)		X	X

Table S-5 Hazardous Events
- Seismic event (earthquake)
- Internal or external FLOODING event
- High winds or tornado strike
- FIRE
- EXPLOSION
- Other events with similar hazard characteristics as determined by the Shift Manager

Table F-1 Fission Product Barrier Matrix

	Fuel Clad (FC) Barrier		Reactor Coolant System (RCS) Barrier		Containment (CNTMT) Barrier	
Category	**Loss**	**Potential Loss**	**Loss**	**Potential Loss**	**Loss**	**Potential Loss**
A RCS or SG Tube Leakage	None	None	1. An automatic or manual ECCS (SI) actuation required by **EITHER** [223]: • UNISOLABLE RCS leakage • SG tube RUPTURE	1. Operation of a standby charging pump is required by **EITHER** [224]: • UNISOLABLE RCS leakage • SG tube leakage 2. CSFST Integrity-**RED** Path conditions met [225]	1. A leaking or RUPTURED SG is FAULTED outside of containment [236]	None
B Inadequate Heat Removal	1. CSFST Core Cooling-**RED** Path conditions met [211]	1. CSFST Core Cooling-**ORANGE** Path conditions met [212] 2. CSFST Heat Sink-**RED** Path conditions met **AND** Heat sink required [213]	None	1. CSFST Heat Sink-**RED** Path conditions met **AND** Heat sink required [227]	None	1. CSFST Core Cooling-**RED** Path conditions met **AND** Restoration procedures **not** effective within 15 min. (Note1) [240]
C CNTMT Radiation / RCS Activity	1. Containment radiation greater than 85 R/hr CTEu16 Containment HRRM (u-RE-6290A), or CTWu17 Containment HRRM (u-RE-6290B) [214] 2. Dose equivalent I-131 coolant activity greater than 300 µCi/cc [216] 3. Gross Failed Fuel Monitor, FFLu60 (u-RE-0406), radiation greater than 1.0E+04 µCi/ml [217]	None	1. Containment radiation greater than 5 R/hr CTEu16 Containment HRRM (u-RE-6290A), or CTWu17 Containment HRRM (u-RE-6290B) [229]	None	None	1. Containment radiation greater than 1,110 R/hr CTEu16 Containment HRRM (u-RE-6290A), or CTWu17 Containment HRRM (u-RE-6290B) [242]
D CNTMT Integrity or Bypass	None	None	None	None	1. Containment isolation is required **AND EITHER** [244]: • Containment integrity has been lost based on Emergency Coordinator judgment • UNISOLABLE pathway from containment to the environment exists 2. Indications of RCS leakage outside of containment [246]	1. CSFST Containment-**RED** Path conditions met [249] 2. Containment hydrogen concentration greater than 4% [250] 3. Containment pressure greater than 18 psig with **neither** Containment Spray system train operating per design for greater than or equal to 15 min. (Note 1) [252]
E EC Judgment	1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the Fuel Clad barrier [221]	1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the Fuel Clad barrier [222]	1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the RCS barrier [234]	1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the RCS barrier [235]	1. **Any** condition in the opinion of the Emergency Coordinator that indicates loss of the Containment barrier [254]	1. **Any** condition in the opinion of the Emergency Coordinator that indicates potential loss of the Containment barrier [255]

Modes:

1	2	3	4	5	6	DEF
Power Operation	Startup	Hot Standby	Hot Shutdown	Cold Shutdown	Refueling	Defueled

Luminant

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Comanche Peak Nuclear Power Plant
EAL Classification Matrix
Revision 13 Page 2 of 3

HOT CONDITIONS
(RCS > 200°F)

	GENERAL EMERGENCY	SITE AREA EMERGENCY	ALERT	UNUSUAL EVENT

C Cold SD/ Refueling System Malfunct.

1 RCS Level

GENERAL EMERGENCY
Loss of RCS inventory affecting fuel clad integrity with Containment challenged

CG1.1 5 6

RCS level less than or equal to 0 in. above upper core plate (top) for greater than or equal to 30 min. (Note 1)
AND
Any Containment Challenge indication, Table C-2 [86]

CG1.2 5 6

RCS level **cannot** be monitored for greater than or equal to 30 min. (Note 1)
AND
Core uncovery is indicated by **any** of the following:
- UNPLANNED increase in **any** Table C-1 sump/tank level of sufficient magnitude to indicate core uncovery
- Erratic Source Range Monitor indication
- Greater than 20,000 R/hr on **any** of the following:
  - CTEu16, Containment HRRM (u-RE-6290A)
  - CTWu17, Containment HRRM (u-RE-6290B)

AND
Any Containment Challenge indication, Table C-2 [90]

Table C-2 Containment Challenge Indications
- CONTAINMENT CLOSURE **not** established (Note 6)
- Containment hydrogen concentration greater than 4%
- Unplanned rise greater than 1 psig in Containment pressure

SITE AREA EMERGENCY
Loss of RCS inventory affecting core decay heat removal capability

CS1.1 5 6

With CONTAINMENT CLOSURE **not** established, RCS level less than 27.3 in. above upper core plate (top) [79]

CS1.2 5 6

With CONTAINMENT CLOSURE established, RCS level less than 0 in. above upper core plate (top) [81]

CS1.3 5 6

RCS water level cannot be monitored for greater than or equal to 30 min. (Note 1)
AND
Core uncovery is indicated by **any** of the following [83]:
- UNPLANNED increase in **any** Table C-1 sump/tank level of sufficient magnitude to indicate core uncovery
- Erratic Source Range Monitor indication
- Greater than 20,000 R/hr on **any** of the following:
  - CTEu16, Containment HRRM (u-RE-6290A)
  - CTWu17, Containment HRRM (u-RE-6290B)

ALERT
Loss of RCS inventory

CA1.1 5 6

Loss of RCS inventory as indicated by RCS level less than 48 in. above upper core plate (top) [75]

CA1.2 5 6

RCS water level cannot be monitored for greater than or equal to 15 min. (Note 1) [77]
AND EITHER
- UNPLANNED increase in **any** Table C-1 sump/tank level due to loss of RCS inventory
- Visual observation of UNISOLABLE RCS leakage

RCS Level Indicators
- RCS Level Wide Range u-LI-3615B
- RCS Level Narrow Range u-LI-3615A
- RCS Extended Wide Range u-LI-3615C
- Mansell Level Monitor System u-LT-3619A/B/C-1, -2
- Plant Computer
- RVLIS
- Ultrasonic Level monitoring (optional)

UNUSUAL EVENT
UNPLANNED loss of RCS inventory for 15 minutes or longer

CU1.1 5 6

UNPLANNED loss of reactor coolant results in RCS level less than a required lower limit for greater than or equal to 15 min. (Note 1) [71]

CU1.2 5 6

RCS water level cannot be monitored
AND EITHER [73]:
- UNPLANNED increase in **any** Table C-1 sump/ tank level due to a loss of RCS inventory
- Visual observation of UNISOLABLE RCS leakage

Table C-1 Sumps/Tanks
- Containment Sump 1
- Containment Sump 2
- Reactor Cavity Sump
- CCW Surge Tank A
- CCW Surge Tank B
- PRT
- RCDT

2 Loss of Emergency AC Power

Table C-3 AC Power Sources

Offsite:
- 138 KV switchyard circuit
- 345 KV switchyard circuit

Onsite:
- uEG1
- uEG2

ALERT
Loss of **all** offsite and **all** onsite AC power to safeguard buses for greater than 15 minutes

CA2.1 5 6 DEF

Loss of **all** offsite and **all** onsite AC power capability, Table C-3, to 6.9 KV safeguard buses uEA1 and uEA2 for greater than or equal to 15 min. (Note 1) [98]

UNUSUAL EVENT
Loss of **all but one** AC power source to safeguard buses for 15 minutes or longer

CU2.1 5 6 DEF

AC power capability, Table C-3, to 6.9 KV safeguard buses uEA1 and uEA2 reduced to a single power source for greater than or equal to 15 min. (Note 1)
AND
Any additional single Table C-3 power source failure will result in loss of **all** AC power to SAFETY SYSTEMS [95]

3 RCS Temp.

GENERAL EMERGENCY: None

Table C-4 RCS Heat-up Duration Thresholds

★ If an RCS heat removal system is in operation within this time frame and RCS temperature is being reduced the EAL is **not** applicable

RCS Status	Containment Closure Status	Heat-up Duration
Intact (but **not** REDUCED INVENTORY)	N/A	60 min. ★
Not intact **OR** REDUCED INVENTORY	Established	20 min. ★
	Not established	0 min.

ALERT
Inability to maintain plant in cold shutdown

CA3.1 5 6

UNPLANNED increase in RCS temperature to greater than 200°F for greater than Table C-4 duration (Notes 1, 9)
OR
UNPLANNED RCS pressure increase greater than 10 psig (This EAL does **not** apply to water-solid plant operations) [104]

UNUSUAL EVENT
UNPLANNED increase in RCS temperature

CU3.1 5 6

UNPLANNED increase in RCS temperature to greater than 200°F (Note 9) [100]

CU3.2 5 6

Loss of **all** RCS temperature and RCS level indication for greater than or equal to 15 min. (Note 1) [102]

4 Loss of Vital DC Power

GENERAL EMERGENCY: None

SITE AREA EMERGENCY: None

UNUSUAL EVENT
Loss of vital DC power for 15 minutes or longer

CU4.1 5 6

Less than 105 VDC bus voltage indications on Technical Specification **required** 125 VDC buses (uED1, uED2, uED3, uED4) for ≥ 15 min. (Note 1) [107]

5 Loss of Comm.

GENERAL EMERGENCY: None

SITE AREA EMERGENCY: None

Table C-5 Communication Methods

System	Onsite	Offsite	NRC
Gai-tronics Page/Party (PA)	X		
Plant Radios	X		
Intra-Plant Phone Sustem (ITS)	X	X	X
Public Telephone	X	X	X
Federal Telephone System (FTS)		X	X

UNUSUAL EVENT
Loss of **all** onsite or offsite communications capabilities

CU5.1 5 6 DEF

Loss of **all** Table C-5 onsite communication methods
OR
Loss of **all** Table C-5 offsite communication methods
OR
Loss of **all** Table C-5 NRC communication methods [109]

6 Hazardous Event Affecting Safety Systems

GENERAL EMERGENCY: None

Table C-6 Hazardous Events
- Seismic event (earthquake)
- Internal or external FLOODING event
- High winds or tornado strike
- FIRE
- EXPLOSION
- Other events with similar hazard characteristics as determined by the Emergency Coordinator

ALERT
Hazardous event affecting a SAFETY SYSTEM needed for the current operating mode

CA6.1 5 6

The occurrence of **any** Table C-6 hazardous event
AND EITHER [111]:
- Event damage has caused indications of degraded performance in at least one train of a SAFETY SYSTEM needed for the current operating mode
- The event has caused VISIBLE DAMAGE to a SAFETY SYSTEM component or structure needed for the current operating mode

UNUSUAL EVENT: None

CONTAINMENT CLOSURE

The procedurally defined actions taken to secure containment and its associated structures, systems, and components as a functional barrier to fission product release under shutdown conditions. Containment closure means that all potential escape paths are closed or capable of being closed:

A. All penetrations providing direct access from Containment atmosphere to outside atmosphere are closed except:
   - Penetrations with automatic valves capable of being closed by an operable CVI
   - Penetrations under administrative controls (e.g., Control Room notified and designated person to close if required by fuel handling accident)

B. Equipment hatch is closed and held in place by 4 bolts, or is capable of being closed and held in place by 4 bolts

C. One emergency airlock door is closed

D. One personnel airlock door is capable of being closed

Notes

Note 1: The Emergency Coordinator should declare the event promptly upon determining that time limit has been exceeded, or will likely be exceeded

Note 6: If CONTAINMENT CLOSURE is re-established prior to exceeding the 30-minute time limit, declaration of a General Emergency is **not** required.

Note 9: Begin monitoring hot condition EALs concurrently

Modes: 1 Power Operation | 2 Startup | 3 Hot Standby | 4 Hot Shutdown | 5 Cold Shutdown | 6 Refueling | DEF Defueled

Luminant

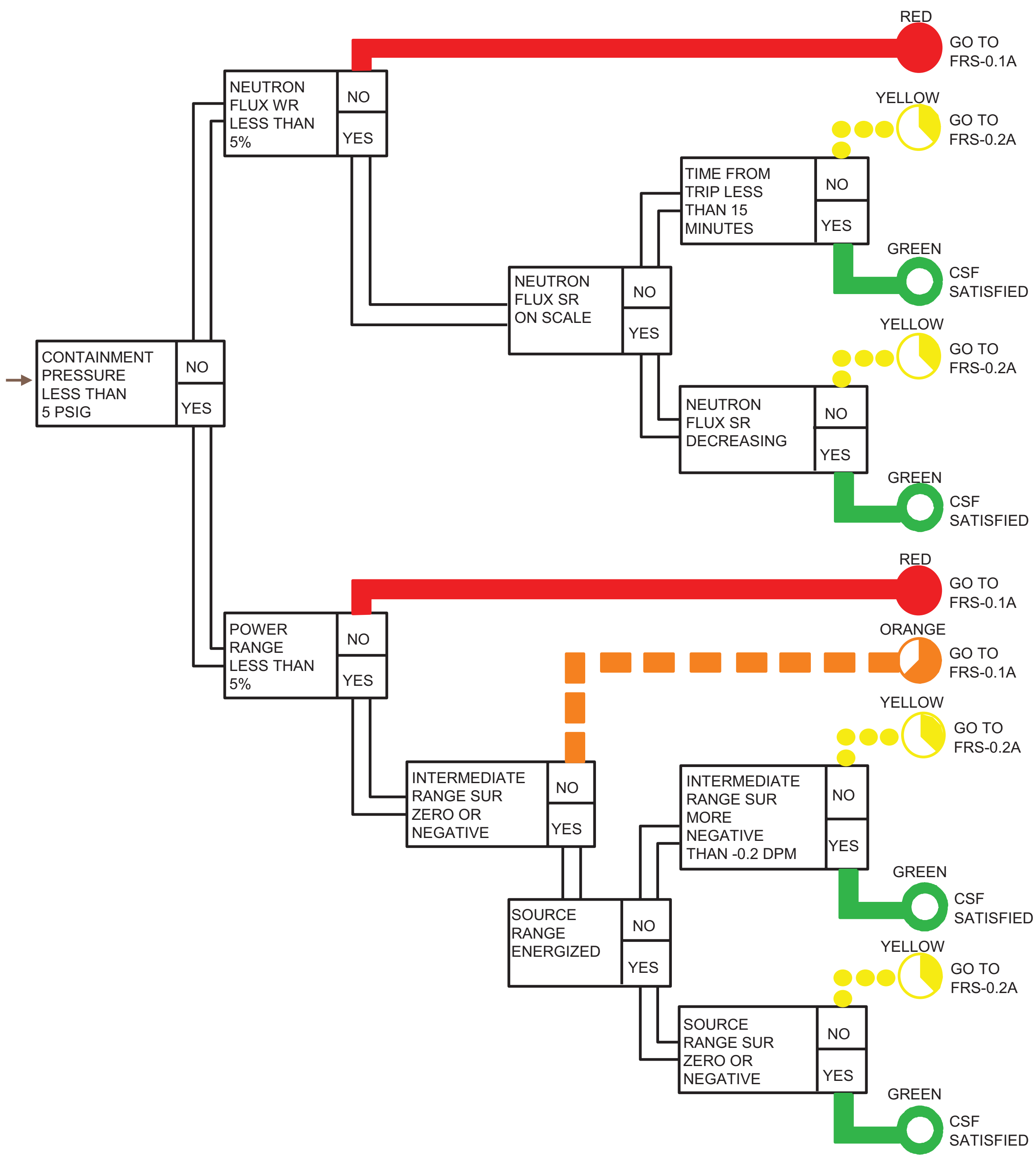
Control Copy # _____

Comanche Peak Nuclear Power Plant
EAL Classification Matrix
Revision 13 Page 3 of 3

COLD CONDITIONS
(RCS ≤ 200°F)

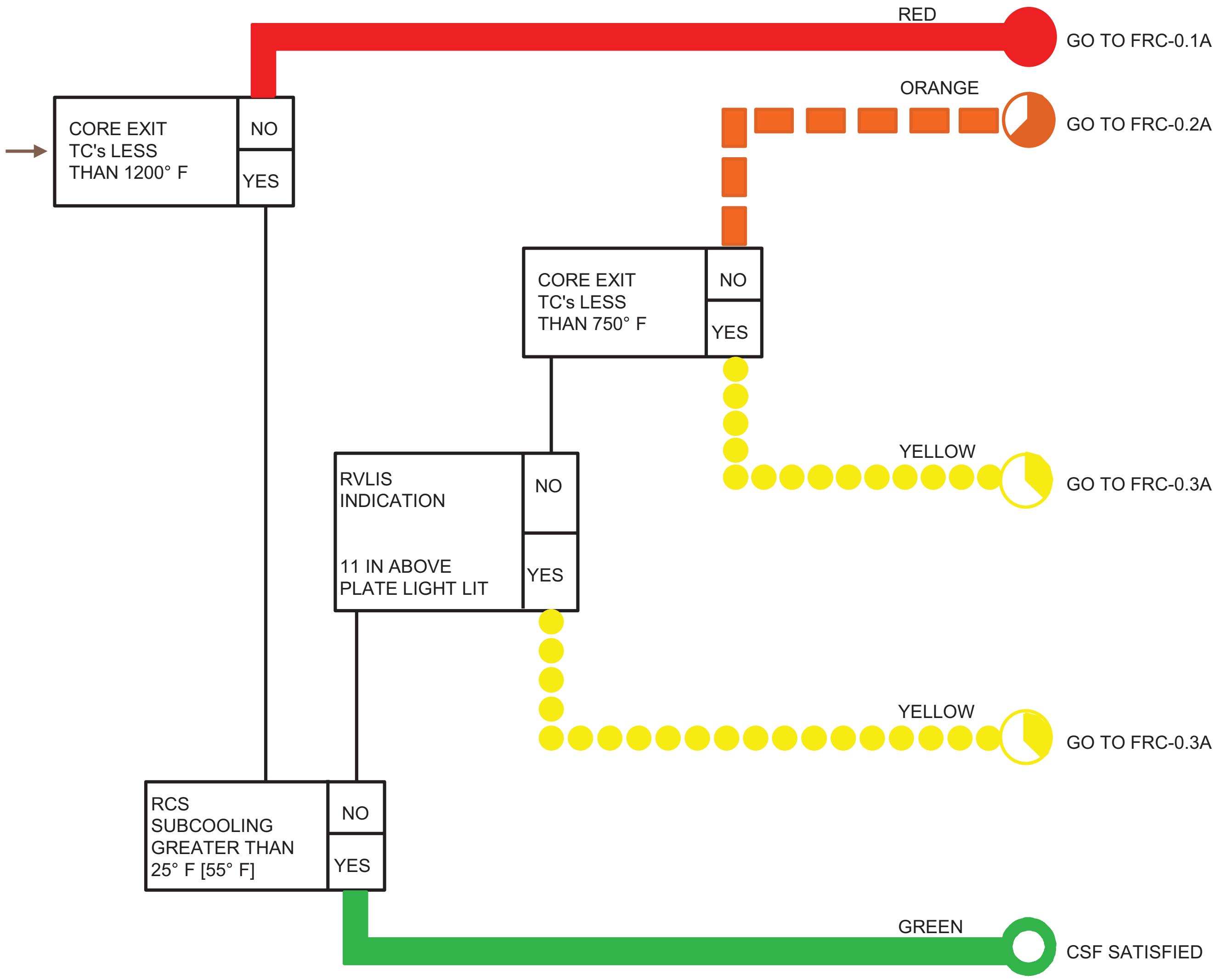
ATTACHMENT 1.A
PAGE 1 OF 1

SUBCRITICALITY STATUS TREE



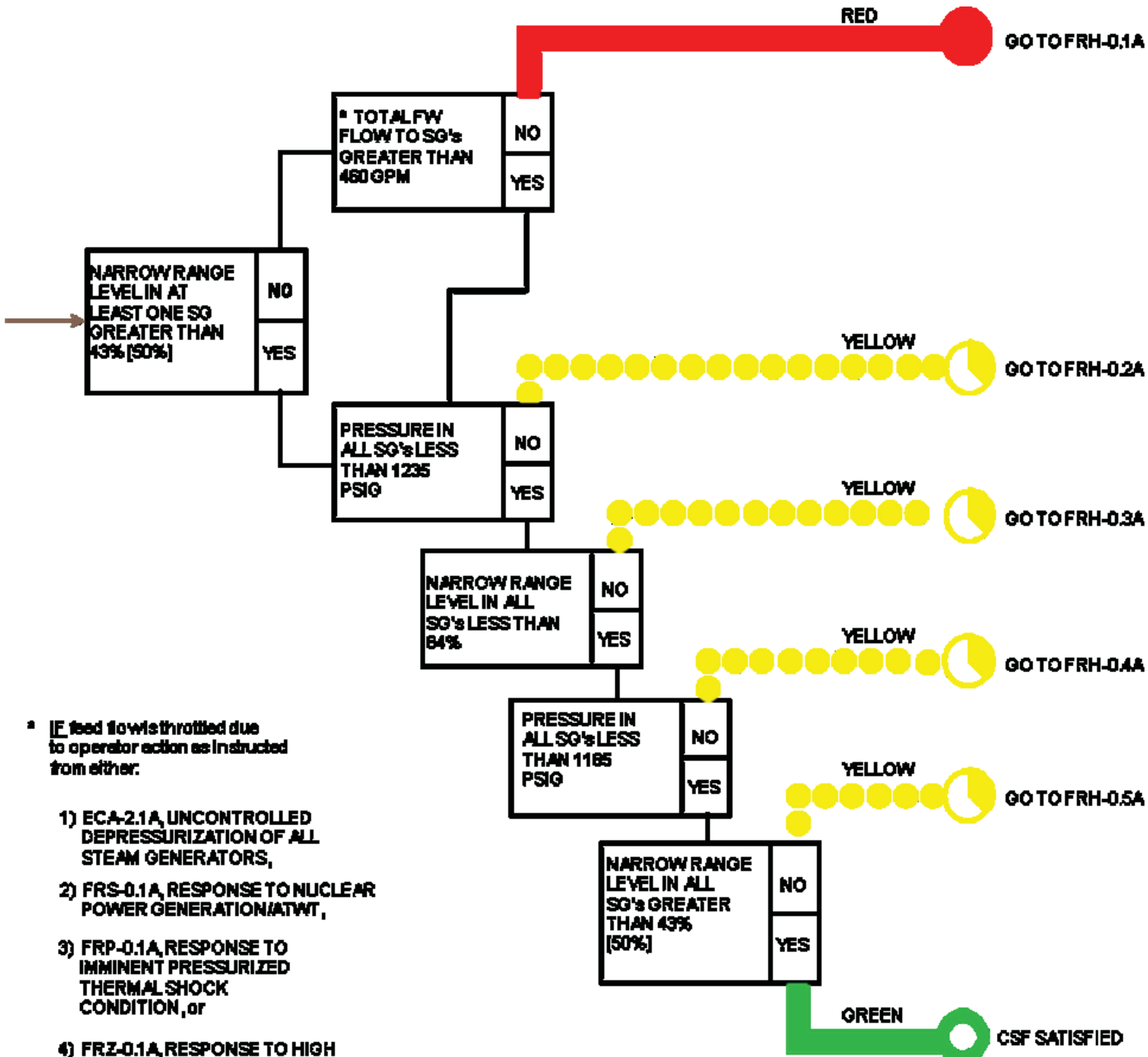
ATTACHMENT 1.A
PAGE 1 OF 1

CORE COOLING STATUS TREE



ATTACHMENT 1.A
PAGE 1 OF 1

HEAT SINK STATUS TREE



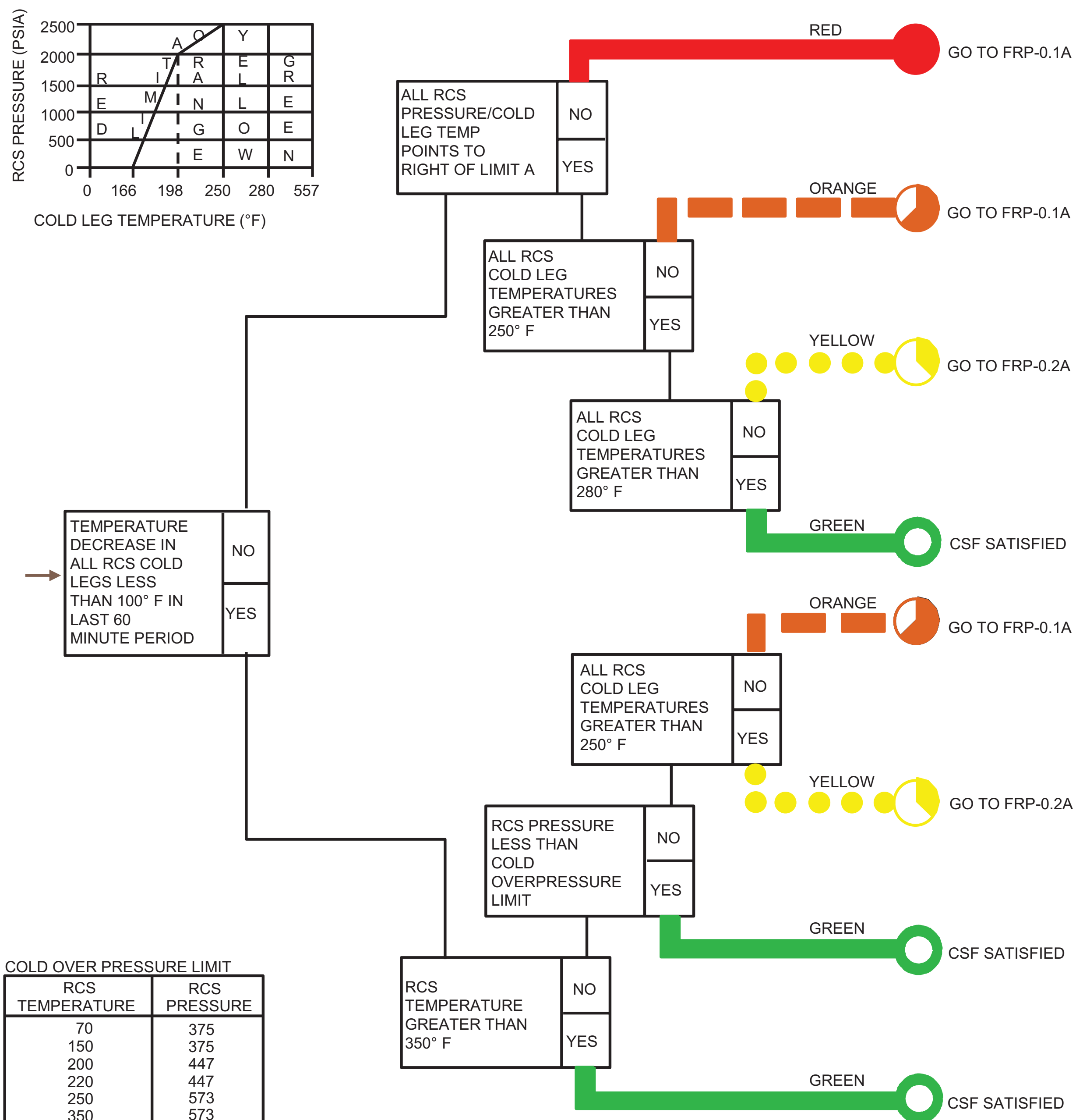
* IF feed flow is throttled due to operator action as instructed from either:

1) ECA-2.1A, UNCONTROLLED DEPRESSURIZATION OF ALL STEAM GENERATORS,
2) FRS-0.1A, RESPONSE TO NUCLEAR POWER GENERATION/ATWT,
3) FRP-0.1A, RESPONSE TO IMMINENT PRESSURIZED THERMAL SHOCK CONDITION, or
4) FRZ-0.1A, RESPONSE TO HIGH CONTAINMENT PRESSURE,

THEN FRH-0.1A does not need to be implemented.

ATTACHMENT 1.A
PAGE 1 OF 1

INTEGRITY STATUS TREE

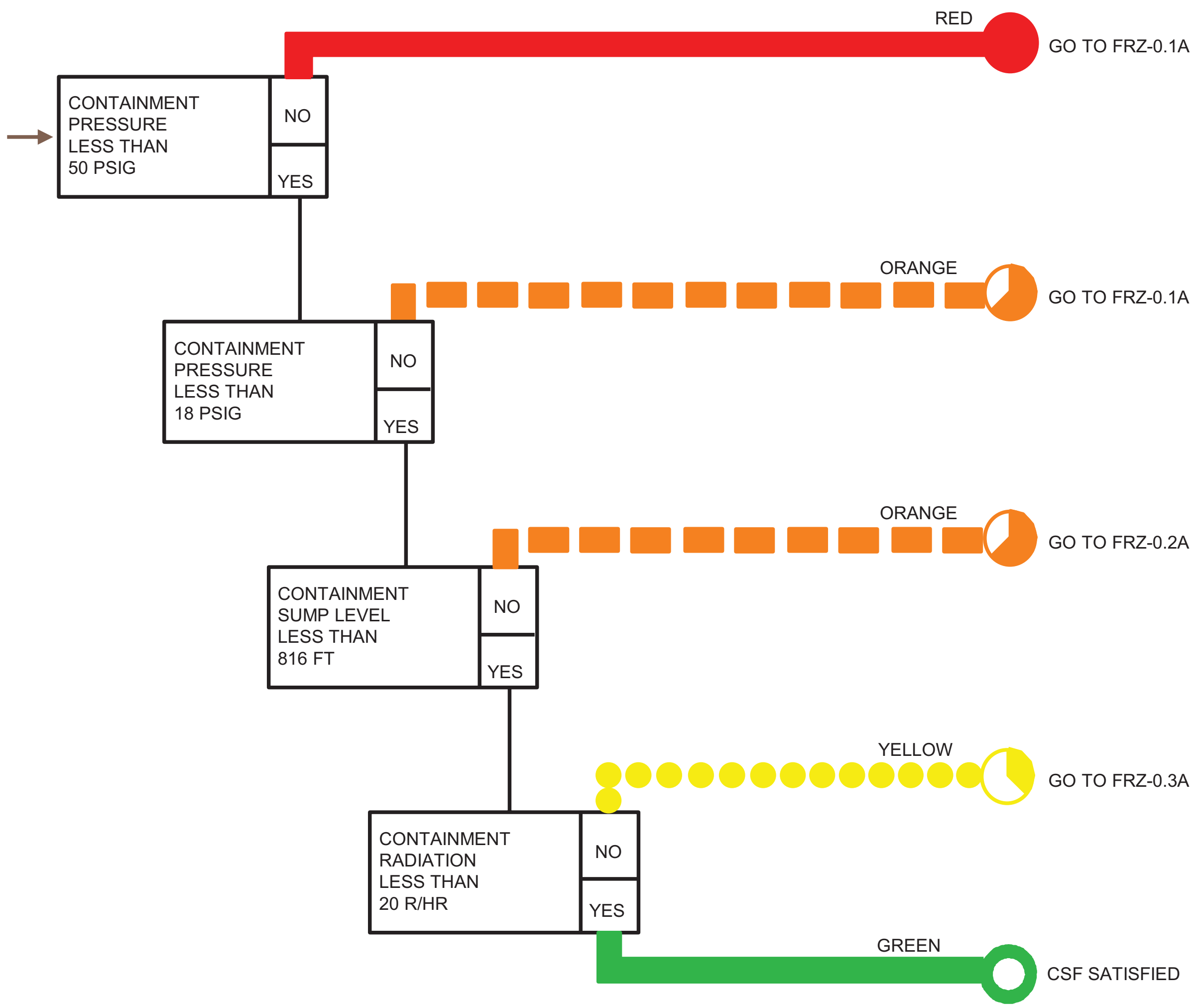


COLD OVER PRESSURE LIMIT

RCS TEMPERATURE	RCS PRESSURE
70	375
150	375
200	447
220	447
250	573
350	573

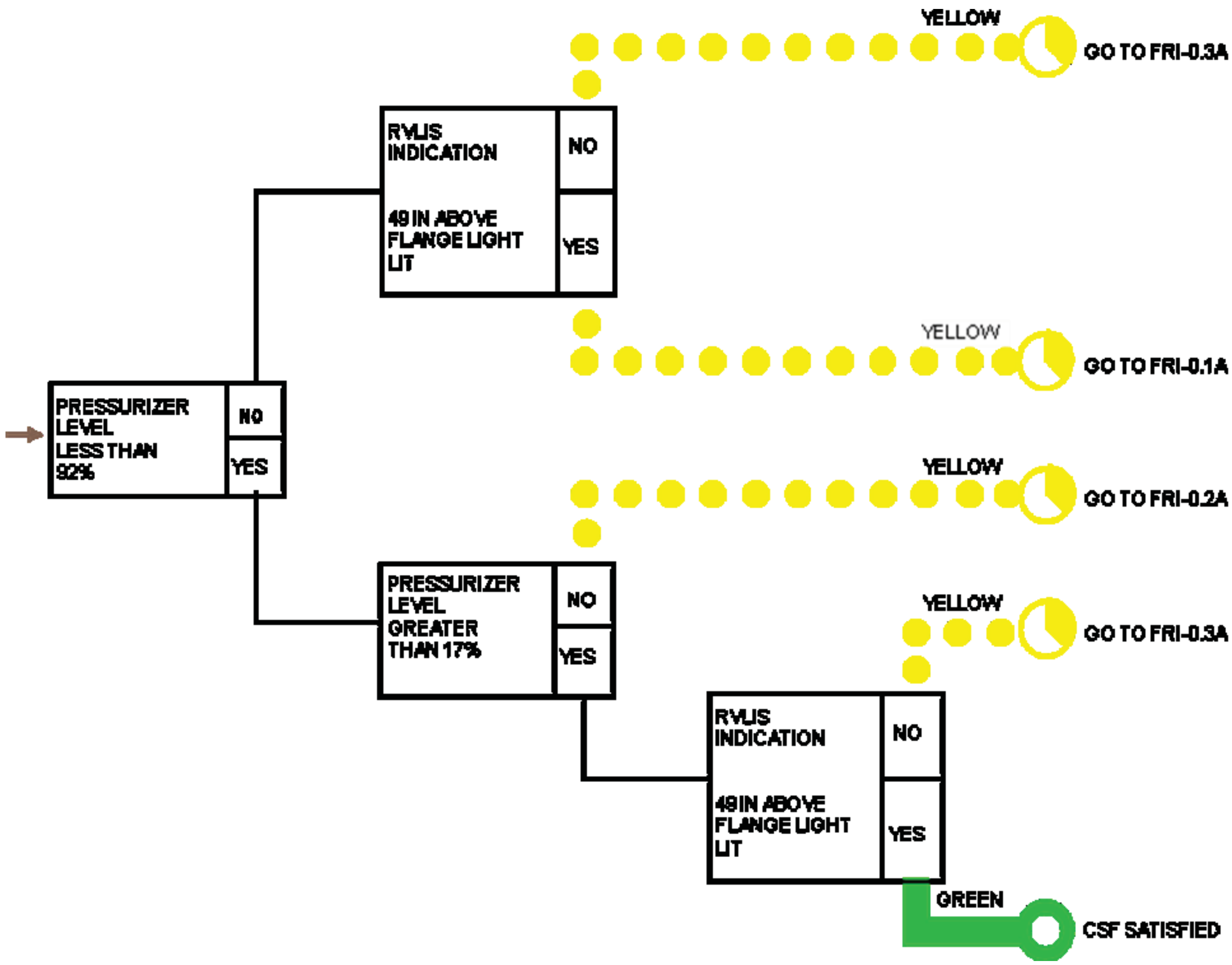
ATTACHMENT 1.A
PAGE 1 OF 1

CONTAINMENT STATUS TREE



ATTACHMENT 1.A
PAGE 1 OF 1

INVENTORY STATUS TREE



Initial Conditions:
At Time 0700

Given the following conditions:

- **Unit 1 experienced a Loss of All Offsite Power 15 minutes ago.**
- **Both Safeguards Buses are deenergized.**
- **Train A Emergency Diesel Generator was just shut down following turbocharger failure.**
- **Train B Emergency Diesel Generator will NOT start in either Emergency or Normal modes.**
- **Pressurizer level is 0%.**
- **Reactor Coolant System pressure is 30 PSIG and stable.**
- **Core Exit Thermocouple temperatures are 780ºF and rising.**
- **Containment pressure is 30 PSIG and stable.**
- **Steam Generator wide range levels are 30% and slowly lowering.**
- **No Reactor Vessel Level Indication System lights are lit.**
- **Turbine Driven Auxiliary Feedwater Pump tripped on overspeed and cannot be reset.**

Initiating Cue:

The Shift Manager directs you to PERFORM the following:

- **DETERMINE the Emergency Action Level Group / Category, Subcategory, and Event Classification per EPP-201, Assessment of Emergency Action Levels, Emergency Classification, and Plan Activation. DETERMINE the MAXIMUM amount of time available to complete the notification.**

EAL Classification Site Area Emergency (SS1.1)

MAXIMUM Amount of Time to Complete Notification 0715 or 15 minutes from Declaration

Updated Conditions: **Given the following conditions:**

Time 0730

- **Unit 1 experienced a Loss of All Offsite Power 45 minutes ago.**
- **Both Safeguards Buses are deenergized.**
- **Train A Emergency Diesel Generator was shut down following turbocharger failure.**
- **Train B Emergency Diesel Generator will NOT start in either Emergency or Normal modes.**
- **Pressurizer level is 0%.**
- **Reactor Coolant System pressure is 30 PSIG and stable.**
- **Core Exit Thermocouple temperatures are 980ºF and slowly rising.**
- **Containment pressure is 30 PSIG and stable.**
- **Steam Generator wide range levels are 20% and slowly lowering.**
- **No Reactor Vessel Level Indication System lights are lit.**
- **Turbine Driven Auxiliary Feedwater Pump has NOT been restored**
- **Off-site power will be restored in 1.5 hours**

Initiating Cue: **Based on the updated conditions, DETERMINE if an <u>upgrade</u> (escalate) or <u>follow-up</u> (update) message is required. DETERMINE the MAXIMUM amount of time to complete the notification message (assume the initial notification time was the initial message time).**

A _______Follow-up_______ message is required

MAXIMUM Amount of Time to Complete Notification _0815__

or 1 hour from Initial Notification________________

Facility: CPNPP JPM # NRC P-1 Task # AO5403 K/A # 004 A4.18 4.3 / 4.1 SF-1

Title: Perform Emergency Boration, Boric Acid Gravity Flow Valve Lineup

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	X	Classroom:	
Actual Performance:		Simulator:	
Alternate Path:		Plant:	X
Time Critical:	X		

READ TO THE EXAMINEE

Provide the Initial Conditions and Initiating Cue to the Examinee. Any special conditions or instructions should be contained on this sheet.

Initial Conditions: Given the following conditions:

- Unit 1 Reactor was tripped
- Digital Rod Position Indication (DRPI) was lost on the Reactor Trip
- Actions of EOP-0.0A, Reactor Trip or Safety Injection are in progress
- Due to a loss of Unit 1 RWST, Control Room operators are lining up for Emergency Boration of Unit 1 by performing ABN-107, Emergency Boration, Attachment 5, Gravity Feed From BA Storage Tanks to Charging Pump Suction
- ABN-107, Emergency Boration, Attachment 6, Boric Acid Gravity Flow Valve Lineup (Unit 1), Section 1 is required to be performed in the field to support Attachment 5

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- ALIGN Gravity Flow from BAT X-01 to Unit 1 per ABN-107, Emergency Boration, Attachment 6, Boric Acid Gravity Flow Valve Lineup (Unit 1), Section 1
- THIS IS A TIME CRITICAL JPM

Task Standard: COMPLETED lineup for Gravity Flow from BAT X-01 to Unit 1. UTILIZED ABN-107, Emergency Boration, Attachment 6. REPORTED completion to Control Room within 15 minutes as required by STI-214.01.

Ref. Materials: ABN-107, Emergency Boration, Attachment 6, Rev. 9.
STI-214.01, Control of Timed Operator Actions, Rev. 1.

Validation Time: 15 minutes Time Critical: 15 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ______________

PLANT SETUP

EXAMINER:
PROVIDE the examinee with the following:

- **ABN-107, Emergency Boration, Attachment 6, Boric Acid Gravity Flow Valve Lineup (Unit 1), Section 1 (Procedure 1)**
- **STI-214.01, Control Timed Operator Actions, Attachment 8.A, CPNPP Timed Operator Actions WITH ≤ 30 MINUTE RESPONSE TIME (Procedure 2)**

EXAMINER NOTE:
This JPM is TIME CRITICAL. The examinee is required to complete the alignment and report completion to Control Room within 15 minutes. The examiner should brief the JPM at the watch stander's desk outside the Boric Acid Tank Room (AB 810', Rm X-206). Time for Critical Actions starts when examinee states that they are ready to begin and ends when lineup is complete AND reported to Control Room.

- **All valves in this JPM have a Time Critical Action (TCA) tag attached to them**
- **If asked, REPORT that ABN-107, Attachment 5, references and requires the use of ABN-107, Attachment 6 to complete Attachment 5**

√ - Check Mark Denotes Critical Step

CRITICAL START TIME:	

Examiner Note:	**The following steps are from ABN-107, Attachment 6, Section 1, and can be performed in any order.**
NOTE: The following valves are located in AB 810', BAT X-01/X-02 Rm (Rm X-206).	
Examiner Cue:	**When located, REPORT Valve Stem up approximately 2½ inches out of valve body. Location: East side of X-01 BAT.**
Perform Step: 1 1st valve	8461A, BA TK X-01 OUT ISOL – OPEN
Standard:	VERIFIED valve open by turning CLOCKWISE then RETURNED valve to FULL OPEN position.
Examiner Cue:	**When manipulated in CLOSE (CW) direction, REPORT handwheel turns freely. When manipulated in OPEN (CCW) direction, REPORT valve stops turning.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Cue:	**When located, REPORT Valve Stem Nut is flush with handwheel. Location: East Wall by X-02 BAT (approx. 2' off floor)**
Perform Step: 2 2nd valve	8465A, BA BATCH TK X-01 TO BA TK X-01 ISOL VLV – CLOSED
Standard:	VERIFIED valve closed by turning CLOCKWISE and DETERMINED valve will not move.
Examiner Cue:	**When manipulated in CLOSE (CW) direction, REPORT handwheel WILL NOT turn.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Cue:	**When located, REPORT Valve Stem Nut is flush with handwheel. Location: BAT Room, East Wall.**
Perform Step: 3√ 3rd valve	1-8507, BA TK X-01 TO U1 CHRG PMP ISOL VLV – OPEN
Standard:	OPENED valve by turning COUNTERCLOCKWISE until valve stopped turning.
Examiner Cue:	**When manipulated in OPEN (CCW) direction, REPORT handwheel turns and stem rises to approximately 2 ½ inches out of body. Then REPORT handwheel becomes hard to turn.**
Comment:	**SAT ☐ UNSAT ☐**

<u>**Examiner Cue:**</u>	**When located, REPORT Valve Stem Nut is flush with handwheel.** <u>**Location: BAT Room, East Wall**</u>**.**
Perform Step: 4 4th valve	8506, BA TK X-01/X-02 TO CHRG PMP XTIE VLV - CLOSED
Standard:	VERIFIED valve closed by turning CLOCKWISE and DETERMINED valve will not move.
<u>**Examiner Cue:**</u>	**When manipulated in CLOSE (CW) direction, REPORT handwheel WILL NOT turn.**
Comment:	**SAT ☐ UNSAT ☐**

<u>**Examiner Cue:**</u>	**When located, REPORT Valve Stem Nut is flush with handwheel.** <u>**Location: BAT Room, East Wall**</u>**.**
Perform Step: 5√ 5th valve	1-8509, BA TK X-01/X-02 TO U1 CHRG PMP ISOL VLV – OPEN
Standard:	OPENED valve by turning COUNTERCLOCKWISE until valve stopped turning.
<u>**Examiner Cue:**</u>	**When manipulated in OPEN (CCW) direction, REPORT handwheel turns and stem rises to approximately 2½ inches out of body. Then REPORT handwheel becomes hard to turn.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**Valves operated in JPM Steps 6, 7, & 8 are diaphragm valves less than 1" in size. OWI-206, Guidelines for Operation of Manual and Power Operated Valves, Step 6.1.2.D states: "DO NOT use two hands to operate a (Diaphragm) valve one inch or less in size."**
Examiner Note:	**Valves operated in JPM Steps 6, 7, & 8 are located approximately 10' above floor and require a ladder to operate. The examinee should locate a suitable ladder (outside of the room) but is not required to carry ladder into the room. Ladder use will be simulated.**
NOTE: The following valves are located in associated Charging Pump Room, AB 810'.	
Examiner Cue:	**REPORT Valve Stem up approximately ½ inch out of valve body. Location: PDP Room X-199 in overhead.**
Perform Step: 6√ 6th valve	1CS-0112, PDP CHRG PMP 1-01 SUCT VNT TO VCT VLV – CLOSED
Standard:	CLOSED valve by turning handwheel in the CLOSED (CLOCKWISE) direction until handwheel hard to turn and stem retracted into body.
Examiner Cue:	**When manipulated in CLOSED (CLOCKWISE) direction, REPORT handwheel turns and stem lowers flush with handwheel nut. Then REPORT handwheel becomes hard to turn.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Cue:	**REPORT Valve Stem up approximately ½ inch out of valve body. Location: CCP 1-01 Room X-200 in overhead.**
Perform Step: 7√ 7th valve	1CS-0113, CCP 1-01 SUCT VNT TO VCT VLV – CLOSED
Standard:	CLOSED valve by turning handwheel in the CLOSED (CLOCKWISE) direction until handwheel hard to turn and stem retracted into body.
Examiner Cue:	**When manipulated in CLOSED (CLOCKWISE) direction, REPORT handwheel turns and stem lowers flush with handwheel nut. Then REPORT handwheel becomes hard to turn.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Cue:	**REPORT Valve Stem up approximately ½ inch out of valve body. Location: CCP 1-02 Room X-201 in overhead.**
Perform Step: 8√ 8th valve	1CS-0114, CCP 1-02 SUCT VNT TO VCT VLV – CLOSED
Standard:	CLOSED valve by turning handwheel in the CLOSED (CLOCKWISE) direction until handwheel hard to turn and stem retracted into body.
Examiner Cue:	**When manipulated in CLOSED (CLOCKWISE) direction, REPORT handwheel turns and stem lowers flush with handwheel nut. Then REPORT handwheel becomes hard to turn.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**TIME CRITICAL ACTIONS are complete when Control Room is contacted in following step.**
Perform Step: 9 Final step	Contact Control Room immediately when lineup is complete.
Standard:	CONTACTED Control Room and REPORTED that lineup is complete.
Terminating Cue:	**When contacted as Control Room, ACKNOWLEDGE communication. This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

CRITICAL STOP TIME:	

Initial Conditions:

Given the following conditions:

- **Unit 1 Reactor was tripped.**
- **Digital Rod Position Indication (DRPI) was lost on the Reactor Trip.**
- **Actions of EOP-0.0A, Reactor Trip or Safety Injection are in progress.**
- **Due to a loss of Unit 1 RWST, Control Room operators are lining up for Emergency Boration of Unit 1 by performing ABN-107, Emergency Boration, Attachment 5, Gravity Feed From BA Storage Tanks to Charging Pump Suction.**
- **ABN-107, Emergency Boration, Attachment 6, Boric Acid Gravity Flow Valve Lineup (Unit 1), Section 1 is required to be performed in the field to support Attachment 5.**

Initiating Cue:

The Unit Supervisor directs you to PERFORM the following:

- **ALIGN <u>Gravity Flow from BAT X-01 to Unit 1</u> per ABN-107, Emergency Boration, Attachment 6, Boric Acid Gravity Flow Valve Lineup (Unit 1), Section 1.**

<u>THIS IS A TIME CRITICAL JPM</u>

ATTACHMENT 6
PAGE 1 OF 4

BORIC ACID GRAVITY FLOW VALVE LINEUP (UNIT 1)

SECTION 1. GRAVITY FLOW FROM BAT X-01 TO UNIT 1

NOTE: The following valves are located in AB 810', BAT X-01/X-02 Rm (Rm X-206).

	VALVE NO.	NOMENCLATURE	VALVE POSITION
☐	8461A	BA TK X-01 OUT ISOL	OPEN
☐	8465A	BA BATCH TK X-01 TO BA TK X-01 ISOL VLV	CLOSED
☐	1-8507	BA TK X-01 TO U1 CHRG PMP ISOL VLV	OPEN
☐	8506	BA TK X-01/X-02 TO CHRG PMP XTIE VLV	CLOSED
☐	1-8509	BA TK X-01/X-02 TO U1 CHRG PMP ISOL VLV	OPEN

NOTE: The following valves are located in associated Charging Pump Room, AB 810'.

	VALVE NO.	NOMENCLATURE	VALVE POSITION
☐	1CS-0112	PDP CHRG PMP 1-01 SUCT VNT TO VCT VLV	CLOSED
☐	1CS-0113	CCP 1-01 SUCT VNT TO VCT VLV	CLOSED
☐	1CS-0114	CCP 1-02 SUCT VNT TO VCT VLV	CLOSED

☐ Contact Control Room immediately when lineup is complete.

Facility: CPNPP JPM # NRC P-2 Task # RO4217 K/A # 055 EA2.03 3.9 / 4.7 SF-6

Title: Alignment of PRZR Heaters with APGs Supplying AC Safeguards Bus (Unit 1 Train B)

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	X	Classroom:	
Actual Performance:		Simulator:	
Alternate Path:		Plant:	X

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Unit 1 is in MODE 3 following a Loss of All AC Power
- 1EA1 has been energized by the Alternate Power Generator
- ECA-0.1A, Loss of All AC Power Recovery Without SI Required is in progress
- The current load on 1EA1 is 2.6 MWs

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- Load the MAXIMUM number of PRZR heaters onto 1EA1 in accordance with ECA-0.1A Attachment 2, Alignment of PRZR Heaters With APGs Supplying AC Safeguards Bus

Task Standard: ENERGIZED 5 PRZR heater groups in accordance with ECA-0.1A Attachment 2.

Ref. Materials: ECA-0.1A, Loss of All AC Power Recovery Without SI Required, Attachment 2.

Validation Time: 15 minutes Time Critical: N/A Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ____________

PLANT SETUP

EXAMINER:

PROVIDE the examinee with a copy of:

- **ECA-0.1A, Loss of All AC Power Recovery Without SI Required, Attachment 2, Alignment of PRZR Heaters with APGs Supplying AC Safeguards Bus (Procedure).**

EXAMINER NOTE:

- **Ensure that a calculator is available for the examinee.**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from ECA-0.1A, Attachment 2.**
Perform Step: 1 1 & 1.A	IF Train "A" AC Safeguards bus energized by the alternate power generator (APG), THEN perform the following to regulate the load of Group A PRZR heaters and to maintain APG limits: Place 1/1-PCP41, PRZR BACKUP HTR GROUP A (CB-05) in OFF
Standard:	CONTACTED Control Room to have 1/1-PCPR1 PLACED in OFF.
Examiner Cue:	**1/1-PCPR1 is OFF.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2√ 1.B & 1st bullet	Locally place the following breakers in OFF (SFGD 852, Train B Switchgear Room): 1EB3-1-1/2/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 01/02/22 SUPPLY BREAKER
Standard:	PLACED 1EB3-1-1/2/BKR in OFF.
Examiner Cue:	**1EB3-1-1/2/BKR is OFF.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3√ 1.B & 2nd bullet	Locally place the following breakers in OFF (SFGD 852, Train B Switchgear Room): 1EB3-1-1/3/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 28/55/56 SUPPLY BREAKER
Standard:	PLACED 1EB3-1-1/3/BKR in OFF.
Examiner Cue:	**1EB3-1-1/3/BKR is OFF.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4√ 1.B & 3rd bullet	Locally place the following breakers in OFF (SFGD 852, Train B Switchgear Room): 1EB3-1-1/4/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 07/08/30 SUPPLY BREAKER
Standard:	PLACED 1EB3-1-1/4/BKR in OFF.
Examiner Cue:	**1EB3-1-1/4/BKR is OFF.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 5√ 1.B & 4th bullet	Locally place the following breakers in OFF (SFGD 852, Train B Switchgear Room): 1EB3-1-1/5/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 34/63/64 SUPPLY BREAKER	
Standard:	PLACED 1EB3-1-1/5/BKR in OFF.	
Examiner Cue:	**1EB3-1-1/5/BKR is OFF.**	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 6√ 1.B & 5th bullet	Locally place the following breakers in OFF (SFGD 852, Train B Switchgear Room): 1EB3-1-2/2/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 19/20/45 SUPPLY BREAKER	
Standard:	PLACED 1EB3-1-2/2/BKR in OFF.	
Examiner Cue:	**1EB3-1-2/2/BKR is OFF.**	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 7√ 1.B & 6th bullet	Locally place the following breakers in OFF (SFGD 852, Train B Switchgear Room): 1EB3-1-2/3/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 43/73/74 SUPPLY BREAKER	
Standard:	PLACED 1EB3-1-2/3/BKR in OFF.	
Examiner Cue:	**1EB3-1-2/3/BKR is OFF.**	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 8√ 1.B & 7th bullet	Locally place the following breakers in OFF (SFGD 852, Train B Switchgear Room): 1EB3-1-2/4/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 01/02/22 SUPPLY BREAKER	
Standard:	PLACED 1EB3-1-2/4/BKR in OFF.	
Examiner Cue:	**1EB3-1-2/4/BKR is OFF.**	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 9 1.C & 1st bullet	Determine maximum number of PRZR heaters that may be energized while maintaining APG below load limit (3 MW): • APG Load Limit – Current APG Load = Available Load
Standard:	CALCULATED • 3 MWs – 2.6 MWs = 0.4 MWs.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 10 1.C & 2nd bullet	Determine maximum number of PRZR heaters that may be energized while maintaining APG below load limit (3 MW): • Available Load / Load per PRZR Heater Breaker = Number of PRZR Heater Breaker(s)
Standard:	CALCULATED • 0.4 MWs / (0.071 MW/PRZR Htr Brkr) = 5.6 PRZR Htr Brkr(s).
Comment:	**SAT ☐ UNSAT ☐**

<u>Examiner Note:</u>	**It is critical that <u>FIVE</u> breakers are energized. As the breakers are bulleted the examinee can choose any of the seven, but must not be stopped until Step 1E is performed.**
Perform Step: 11√ 1.D & 1st bullet	Place selected Pressurizer Backup Group A Heaters to ON as determined by Step 1C: 1EB3-1-1/2/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 01/02/22 SUPPLY BREAKER
Standard:	PLACED 1EB3-1-1/2/BKR in ON.
<u>Examiner Cue:</u>	**1EB3-1-1/2/BKR is ON.**
Comment:	**SAT ☐ UNSAT ☐ N/A ☐**

Perform Step: 12√ 1.D & 2nd bullet	Place selected Pressurizer Backup Group A Heaters to ON as determined by Step 1C: 1EB3-1-1/3/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 28/55/56 SUPPLY BREAKER
Standard:	PLACED 1EB3-1-1/3/BKR in ON.
<u>Examiner Cue:</u>	**1EB3-1-1/3/BKR is ON.**
Comment:	**SAT ☐ UNSAT ☐ N/A ☐**

Perform Step: 13√ 1.D & 3rd bullet	Place selected Pressurizer Backup Group A Heaters to ON as determined by Step 1C: 1EB3-1-1/4/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 07/08/30 SUPPLY BREAKER	
Standard:	PLACED 1EB3-1-1/4/BKR in ON.	
Examiner Cue:	**1EB3-1-1/4/BKR is ON.**	
Comment:		**SAT** ☐ **UNSAT** ☐ **N/A** ☐

Perform Step: 14√ 1.D & 4th bullet	Place selected Pressurizer Backup Group A Heaters to ON as determined by Step 1C: 1EB3-1-1/5/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 34/63/64 SUPPLY BREAKER	
Standard:	PLACED 1EB3-1-1/5/BKR in ON.	
Examiner Cue:	**1EB3-1-1/5/BKR is ON.**	
Comment:		**SAT** ☐ **UNSAT** ☐ **N/A** ☐

Perform Step: 15√ 1.D & 5th bullet	Place selected Pressurizer Backup Group A Heaters to ON as determined by Step 1C: 1EB3-1-2/2/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 19/20/45 SUPPLY BREAKER	
Standard:	PLACED 1EB3-1-2/2/BKR in ON.	
Examiner Cue:	**1EB3-1-2/2/BKR is ON.**	
Comment:		**SAT** ☐ **UNSAT** ☐ **N/A** ☐

Perform Step: 16√ 1.D & 6th bullet	Place selected Pressurizer Backup Group A Heaters to ON as determined by Step 1C: 1EB3-1-2/3/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 43/73/74 SUPPLY BREAKER	
Standard:	PLACED 1EB3-1-2/3/BKR in ON.	
Examiner Cue:	**1EB3-1-2/3/BKR is ON.**	
Comment:		**SAT** ☐ **UNSAT** ☐ **N/A** ☐

Perform Step: 17√ 1.D & 7th bullet	Place selected Pressurizer Backup Group A Heaters to ON as determined by Step 1C: 1EB3-1-2/4/BKR, PRESSURIZER 1-01 BACKUP GROUP 1 HEATERS 01/02/22 SUPPLY BREAKER
Standard:	PLACED 1EB3-1-2/4/BKR in ON.
Examiner Cue:	**1EB3-1-2/4/BKR is ON.**
Comment:	**SAT** ☐ **UNSAT** ☐ **N/A** ☐

Perform Step: 18 2.E	Notify the RO that 1/1-PCPR1, PRZR BACKUP HTR GROUP A can be placed in ON/OFF to cycle PRZR heaters for the purpose of controlling pressure.
Standard:	NOTIFIED the RO that Attachment 2 is complete.
Examiner Cue:	**The JPM is complete.**
Comment:	**SAT** ☐ **UNSAT** ☐

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Unit 1 is in MODE 3 following a Loss of All AC Power**
- **1EA1 has been energized by the Alternate Power Generator**
- **ECA-0.1A, Loss of All AC Power Recovery Without SI Required is in progress**
- **The current load on 1EA1 is 2.6 MWs**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **Load the MAXIMUM number of PRZR heaters onto 1EA1 in accordance with ECA-0.1A Attachment 2, Alignment of PRZR Heaters With APGs Supplying AC Safeguards Bus**

ATTACHMENT 2
PAGE 1 OF 4

ALIGNMENT OF PRZR HEATERS WITH APGs SUPPLYING AC SAFEGUARDS BUS

1. IF Train “A” AC Safeguards bus energized by the alternate power generator (APG), THEN perform the following to regulate the load of Group A PRZR heaters and to maintain APG load limits:

☐ A. Place 1/1-PCPR1, PRZR BACKUP HTR GROUP A (CB-05) in OFF.

B. Locally place the following breakers in OFF (SFGD 852, Train B Switchgear Room):

- ☐ 1EB3-1-1/2/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 01/02/22 SUPPLY BREAKER
- ☐ 1EB3-1-1/3/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 28/55/56 SUPPLY BREAKER
- ☐ 1EB3-1-1/4/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 07/08/30 SUPPLY BREAKER
- ☐ 1EB3-1-1/5/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 34/63/64 SUPPLY BREAKER
- ☐ 1EB3-1-2/2/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 19/20/45 SUPPLY BREAKER
- ☐ 1EB3-1-2/3/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 43/73/74 SUPPLY BREAKER
- ☐ 1EB3-1-2/4/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 13/14/37 SUPPLY BREAKER

C. Determine maximum number of PRZR heaters that may be energized while maintaining APG below load limit (3 MW):

- APG Load Limit - Current APG Load = Available Load

  3 MWs - ________________ MWs = ________________ MWs

- Available Load / Load per PRZR Heater Breaker = Number of PRZR Heater Breakers(s)

  __________ MWs / (0.071MW/PRZR Htr Brkr) = ________ PRZR Htr Brkr(s)

ATTACHMENT 2
PAGE 2 OF 4

ALIGNMENT OF PRZR HEATERS WITH APGs SUPPLYING AC SAFEGUARDS BUS

1. D. Place selected Pressurizer Backup Group A Heaters to ON as determined by Step 1C:

- ☐ • 1EB3-1-1/2/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 01/02/22 SUPPLY BREAKER
- ☐ • 1EB3-1-1/3/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 28/55/56 SUPPLY BREAKER
- ☐ • 1EB3-1-1/4/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 07/08/30 SUPPLY BREAKER
- ☐ • 1EB3-1-1/5/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 34/63/64 SUPPLY BREAKER
- ☐ • 1EB3-1-2/2/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 19/20/45 SUPPLY BREAKER
- ☐ • 1EB3-1-2/3/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 43/73/74 SUPPLY BREAKER
- ☐ • 1EB3-1-2/4/BKR, PRESSURIZER 1-01 BACKUP GROUP A HEATERS 13/14/37 SUPPLY BREAKER

☐ E. Notify the RO that 1/1-PCPR1, PRZR BACKUP HTR GROUP A can be placed in ON/OFF to cycle PRZR heaters for the purpose of controlling RCS pressure.

Facility: CPNPP JPM # NRC P-3 Task # AO6413 K/A # 068 AA1.22 4.0 / 4.3

Title: Response to Fire in the Control Room or Cable Spreading Room, NEO #2 Actions

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	X	Classroom:	______
Actual Performance:	______	Simulator:	______
Alternate Path:	X	Plant:	X
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Unit 1 has entered ABN-803A, Response to Fire in the Control Room or Cable Spreading Room
- Attachment 4, Nuclear Equipment Operator No. 2 Actions to Achieve Hot Shutdown are in progress

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- Continue with ABN-803A, Response to Fire in the Control Room or Cable Spreading Room Attachment 4, (Nuclear Equipment Operator No. 2 Actions to Achieve Hot Shutdown) at Step "l"
- The RO at the RSP has just informed you that CCW pump 1-01 is running

Task Standard: PERFORMED Steps "l" through "n" of ABN-803A, Response to Fire in the Control Room or Cable Spreading Room, Attachment 4 including starting Safety Chiller 1-05.

Ref. Materials: ABN-803A, Response to Fire in the Control Room or Cable Spreading Room, Attachment 4, Nuclear Equipment Operator No. 2 Actions to Achieve Hot Shutdown, Rev 13.

Validation Time: 10 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ______________

PLANT SETUP

EXAMINER:

PROVIDE the examinee with a copy of:

- **ABN-803A, Attachment 4 marked through performance of Step k.**

EXAMINER NOTE:

- **IF the examinee requests to look inside the Safety Chiller Panel during Perform Step 2 or 3, THEN provide the Attachment of this JPM.**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from ABN-803A, Attachment 4**
Examiner Note:	**The following represents the Alternate Path of this JPM.**
Examiner Note:	**ECB 778 Unit 1 Safety Chiller Equipment Room (Rm 1-115A)**
Examiner Cue:	**The RO at the RSP informs you that CCW pump 1-01 is running.**
Examiner Cue:	**When the examinee arrives at the Unit 1 Train A Safety Chiller:** • **Power ON and System Run lights are DARK**
NOTE: Auxiliary oil pump will run for approximately 30 seconds prior to compressor start.	
Perform Step: 1 step I & I.1)	WHEN CCW pump is running, THEN ensure Safety Chiller 1-05 – RUNNING IF Safety Chiller NOT running, THEN perform the following: Verify Recirculation Pump running.
Standard:	CHECKED Recirculation Pump 1-05 running.
Examiner Cue:	**The Recirculation Pump is running.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**If the examinee requests to look inside the Safety Chiller Panel during performance step 2 or 3, then provide Attachment 1 of this JPM.**
Perform Step: 2√ step I & I.2)	WHEN CCW pump is running, THEN ensure Safety Chiller 1-05 – RUNNING IF Safety Chiller NOT running, THEN perform the following: Place STOP/RESET-START switch (1-HS-6710A) in STOP/RESET.
Standard:	PLACED 1-HS-6710A in STOP/RESET.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3√ step I & I.3)	WHEN CCW pump is running, THEN ensure Safety Chiller 1-05 – RUNNING IF Safety Chiller NOT running, THEN perform the following: Place STOP/RESET-START switch in START.
Standard:	PLACED 1-HS-6710A in START.
Examiner Cue:	**Power ON and System Run lights are LIT. The Safety Chiller is running.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**SFGD 790, Corridor Outside CS Chem Add Tk Room, (RM 1-070)**
Examiner Cue:	**The Position Indicator is at the Top in line with the OPEN indication.**
NOTE: The following valves are difficult to locally operate. Contact the Remote Shutdown Panel if assistance is needed to close these valves.	
Perform Step: 4√ step m & 1st Bullet	Ensure the following valves – CLOSED. 1-8812A, RWST 1-01 TO RHR PMP 1-01 SUCT VLV
Standard:	• DEPRESSED Declutch lever. • ROTATED Handwheel in the Clockwise direction.
Examiner Cue:	**The Handwheel has stopped turning and Position Indicator is at the Bottom in line with the CLOSED indication.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Cue:	**The Position Indicator is at the Top in line with the OPEN indication.**
Perform Step: 5√ step m & 2nd Bullet	Ensure the following valves – CLOSED. 1-8812B, RWST 1-01 TO RHR PMP 1-02 SUCT VLV
Standard:	• DEPRESSED Declutch lever. • ROTATED Handwheel in the Clockwise direction.
Examiner Cue:	**The Handwheel has stopped turning and Position Indicator is at the Bottom in line with the CLOSED indication.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**For each Steam Generator either an upstream or downstream isolation valve may be used for throttling.** **The valves are normally "Locked Open", the examinee will need to indicate that he has cut the seal before the valve can be moved.**
Examiner Cue:	**Once examinee arrives at throttle valves provide the following cue:** **The RO reports the Initial Flow Rates are as follows:** • **Steam Generator # 1 is 300 gpm.** • **Steam Generator # 2 is 300 gpm.** • **Total Flow from MDAFW Pump 1-01 is 650 gpm.** **The RO desires 150 gpm to each Steam Generator and total flow from MDAFW Pump 1-01 of 400 gpm.**
Perform Step: 6 √ step n SG 1-01	Train A MD AFW PMP Room (SG 790' 1-072) As directed by the RO, locally control auxiliary feedwater flow to Steam Generators 1 and 2: SG 1-01 • 1AF-0074, MD AFW PMP 1-01 DISCH TO SG 1-01 UPSTRM ISOL VLV OR • 1AF-0121, MD AFW PMP 1-01 DISCH TO SG 1-01 DNSTRM ISOL VLV
Standard:	UNLOCKED and THROTTLED CLOSED 1AF-0074 or 1AF-0121 by ROTATING handwheel in CLOCKWISE direction.
Examiner Cue:	**Once examinee has demonstrated throttling the valve closed, provide examinee with the modified flow rates:** **Steam Generator # 1 is 100 gpm.** **Steam Generator # 2 is 350 gpm.** **Total Flow from MDAFW Pump 1-01 is 525 gpm.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 7 √ Step n SG 1-02	Train A MD AFW PMP Room (SG 790' 1-072) As directed by the RO, locally control auxiliary feedwater flow to Steam Generators 1 and 2: <u>SG 1-02</u> • 1AF-0082, MD AFW PMP 1-01 DISCH TO SG 1-02 UPSTRM ISOL VLV OR • 1AF-0123, MD AFW PMP 1-01 DISCH TO SG 1-02 DNSTRM ISOL VLV
Standard:	UNLOCKED and THROTTLED CLOSED 1AF-0082 or 1AF-0123 by ROTATING handwheel in CLOCKWISE direction.
<u>**Examiner Cue:**</u>	**Once examinee has demonstrated throttling the valve closed, provide examinee with the modified flow rates:** **Steam Generator # 1 is 150 gpm.** **Steam Generator # 2 is 150 gpm.** **Total Flow from MDAFW Pump 1-01 is 400 gpm.**
<u>**Examiner Cue:**</u>	**This JPM is Complete.**
Comment:	**SAT** ☐ **UNSAT** ☐

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Unit 1 has entered ABN-803A, Response to Fire in the Control Room or Cable Spreading Room**
- **Attachment 4, Nuclear Equipment Operator No. 2 Actions to Achieve Hot Shutdown are in progress**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **Continue with ABN-803A, Response to Fire in the Control Room or Cable Spreading Room Attachment 4, (Nuclear Equipment Operator No. 2 Actions to Achieve Hot Shutdown) at Step "l"**
- **The RO at the RSP has just informed you that CCW pump 1-01 is running**

THIS JPM IS NOT TIME CRITICAL

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

ABNORMAL CONDITIONS PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ______/______ LATEST PCN/EFFECTIVE DATE 3 / 9/14/16 1200

QUALITY RELATED

RESPONSE TO A FIRE IN THE
CONTROL ROOM OR CABLE SPREADING ROOM

PROCEDURE NO. ABN-803A

REVISION NO. 13

EFFECTIVE DATE: 8-27-15 1200

PREPARED BY (Print): J.D. STONE Ext: 0564

TECHNICAL REVIEW BY (Print): DILLON RICHEY Ext: 6769

APPROVED BY: Joe Ricks for D. McGaughey Date: 8/24/15
DIRECTOR, OPERATIONS

ATTACHMENT 4
PAGE 1 OF 4

Nuclear Equipment Operator NO. 2 ACTIONS TO ACHIEVE HOT SHUTDOWN

SFGD 832 West of Reactor Trip Brks (Rm 1-096)

☐ a. PROCEED to Remote Shutdown Panel AND OBTAIN a copy of this procedure.

NOTE:
- Communications will be performed using channel 3 on two way radio.
- All breakers and junction boxes to be manipulated while completing this procedure have been demarcated with a luminescent diagonal stripe or TCA label.
- STA-124 FPE is NOT required for breaker operations.

SFGD 852, Trn B Switchgear Room (Rm 1-103)

b. ENSURE the following CONTROL POWER Supply AND breakers - **OFF/OPEN**

NOTE: 1ED2-2 Panel is located N. of 1EA2 on column.

1) PLACE the following breaker - **OFF:**

☐ • 1ED2-2/1/BKR, 6.9 KV SWITCHGEAR 1EA2 125 VDC SUPPLY BREAKER

☐ 2) ENSURE the following breakers - **OPEN**:

- 1EA2/16/BKR 1EG2, DG 1-02 TO 6.9 KV SWGR 1EA2 EMERGENCY FEEDER BREAKER
- 1EA2/17/BKR 1EA2-2, XFMR XST1 TO 6.9 KV SWGR 1EA2 ALTERNATE FEEDER BREAKER
- 1EA2/2/BKR 1EA2-1, XFMR XST2 TO 6.9 KV SWGR 1EA2 PREFERRED FEEDER BREAKER

SG 832 Penetration Valve Room, N. End (Rm 1-088)

☐ c. ENSURE 1-HV-4709, U1 THBR CLR CCW RET ORC ISOL VLV - **CLOSED**

SFGD 810 North Penetration Room, (Rm 1-077A)

[R] ☐ d. ENSURE 1-8100, U1 RCP SL WTR RET ISOL VLV - **CLOSED**

Nuclear Equipment Operator NO. 2 ACTIONS TO ACHIEVE HOT SHUTDOWN

SFGD 790 Coridor near TDAFWP Air Accumulators, (Rm 1-070)

e. START CCP 1-01 Area Fan

☑ 1) 1-HS-5802B, CCP AREA FAN COOLER 03 - **LOCAL**

☑ 2) 1-HS-5802C, CCP AREA FAN COOLER 03 - **CLOSE**

SFGD 790 North/South Corridor, (Rm 1-070)

f. PLACE the following breakers - **OFF**:

- ☑ 1EB3-1/1G/BKR, RWST TO RESIDUAL HEAT REMOVAL PMP 1-01 SUCT VLV 1-8812A MOTOR BREAKER
- ☑ 1EB3-1/3M/DSW, SSW TRAIN A TO UNIT 1 AFW PUMP SUCTION VALVE 4395 MOTOR FUSED SWITCH
- ☑ 1EB3-1/6J/BKR, SFGD LOOP A COMPONENT COOLING WTR RETURN VALVE 1-HV-4512 MOTOR BREAKER
- ☑ 1EB3-1/7C/BKR, RHR HEAT EXCHANGER 1-01 CCW RETURN VALVE 4572 MOTOR BREAKER
- ☑ 1EB3-1/7F/BKR, CS HEAT EXCHANGER 1-01 CCW RETURN VALVE 4574 MOTOR BREAKER

☑ g. ENSURE 1EB3-1/1CR/BKR, ALT PWR SOURCE TO DISTR PNL 1C3 VIA XFMR T1C3 AND TR-1C3 - **ON**.

SFGD 790, TDAFW Pump Room, (Rm 1-074)

☑ h. ENSURE 1-HV-2452, AFWPT 1-01 TRIP AND THROT VLV - **CLOSED**.

SFGD 790, Corridor Outside MDAFW Pump Room, (Rm 1-071)

i. START AFW Pump Area Fan 1-07.

☑ 1) 1-HS-5676B, LOCAL/REMOTE SELECTOR SWITCH - MOT DRVN FW PMP RM FAN 07 - **LOCAL**

☑ 2) 1-HS-5676C, LOCAL CONTROL SWITCH - MOTOR DRIVEN FW PUMP ROOM FAN 07 - **START**

ATTACHMENT 4
PAGE 3 OF 4

Nuclear Equipment Operator NO. 2 ACTIONS TO ACHIEVE HOT SHUTDOWN

SFGD 790, Corridor Outside CS Chem Add Tk Room in Overhead, (Rm 1-070)

> NOTE:
> - To provide miniflow for CCWP 1-01, 1-HV-4572 should be positioned at least partially open.
> - Ladder required, located 790 Hallway.

☒ j. THROTTLE 1-HV-4572, RHR HX 1-01 CCW RET VLV - **OPEN** (30%).

☒ k. NOTIFY RO at RSP that CCW Pump 1-01 may be aligned and started.

ECB 778 Unit 1 Safety Chiller Equipment Room (Rm 1-115A)

☐ l. WHEN CCW pump 1-01 is running,
THEN
ENSURE Safety Chiller 1-05 - **RUNNING**.

> NOTE: Auxiliary oil pump will run for approximately 30 seconds prior to compressor start.

IF Safety Chiller NOT running,
THEN
PERFORM the following:

☐ 1) VERIFY Recirculation Pump running.

☐ 2) PLACE STOP/RESET-START switch (1-HS-6710A) in **STOP/RESET**.

☐ 3) PLACE STOP/RESET-START switch in **START**.

SFGD 790, Corridor Outside CS Chem Add Tk Room, (Rm 1-070)

> NOTE: The following valves are difficult to locally operate. Contact the Remote Shutdown Panel if assistance is needed to close these valves.

m. ENSURE the following valves - **CLOSED**:

☐ • 1-8812A, RWST 1-01 TO RHR PMP 1-01 SUCT VLV

☐ • 1-8812B, RWST 1-01 TO RHR PMP 1-02 SUCT VLV

Nuclear Equipment Operator NO. 2 ACTIONS TO ACHIEVE HOT SHUTDOWN

SFGD 790 Trn A MDAFWP Room, (Rm 1-072)

n. As directed by the RO, locally CONTROL auxiliary feedwater flow to Steam Generators 1 and 2:

☐ SG 1-01 (Select ONE valve per Steam Generator)

- 1AF-0074, MD AFW PMP 1-01 DISCH TO SG 1-01 UPSTRM ISOL VLV

OR

- 1AF-0121, MD AFW PMP 1-01 DISCH TO SG 1-01 DNSTRM ISOL VLV

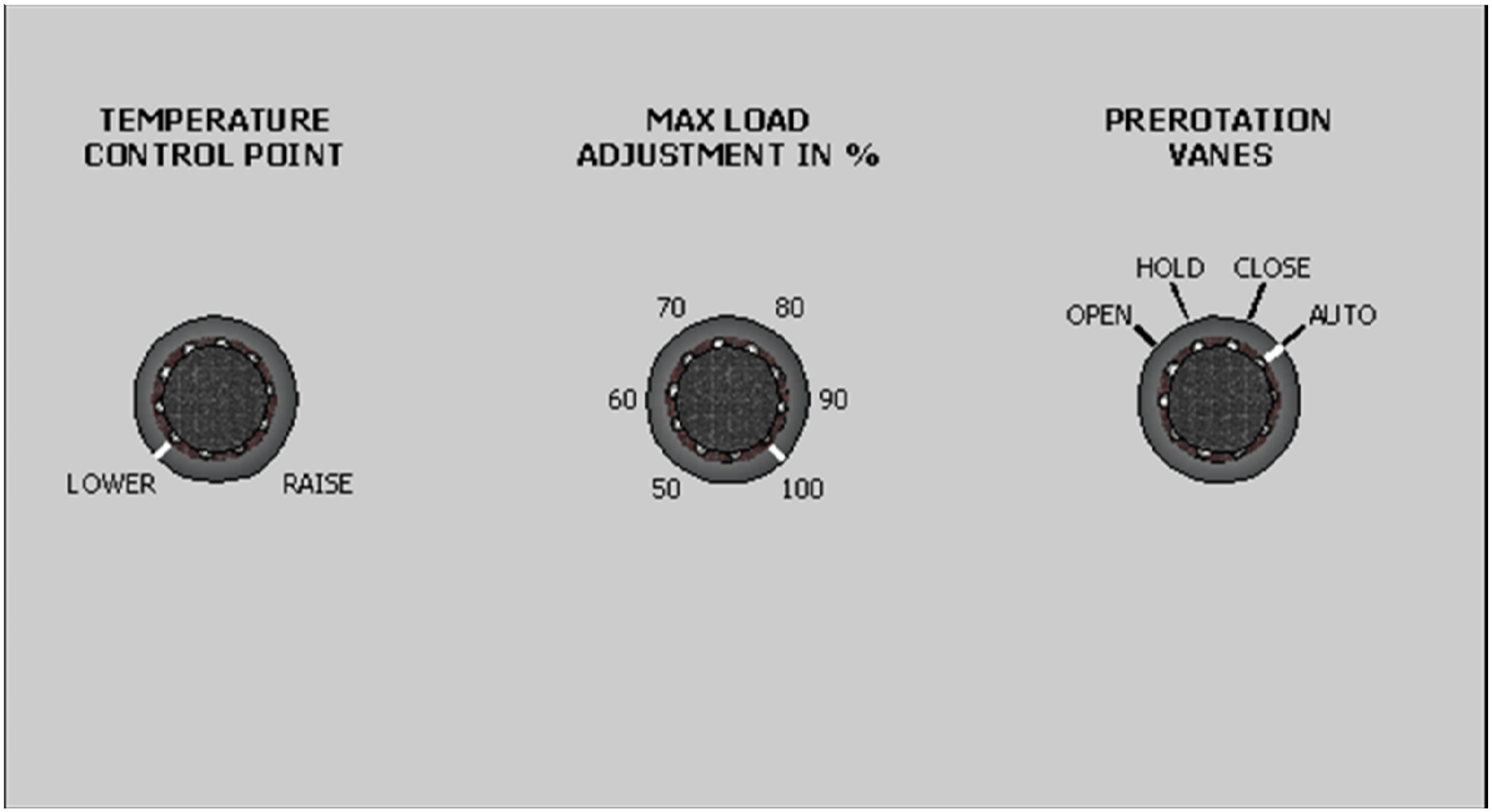
☐ SG 1-02 (Select ONE valve per Steam Generator)

- 1AF-0082, MD AFW PMP 1-01 DISCH TO SG 1-02 UPSTRM ISOL VLV

OR

- 1AF-0123, MD AFW PMP 1-01 DISCH TO SG 1-02 DNSTRM ISOL VLV

Top


TEMPERATURE
CONTROL POINT
LOWER
RAISE
MAX LOAD
ADJUSTMENT IN %
70
80
60
90
50
100
PREROTATION
VANES
HOLD
CLOSE
OPEN
AUTO

Facility: CPNPP JPM # NRC S-1 Task # RO1008M K/A # 001 A4.03 4.0 / 3.7 SF-1

Title: Perform Control Rod Exercises

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:		Classroom:	
Actual Performance:	X	Simulator:	X
Alternate Path:	X	Plant:	

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Unit 1 is operating at 97% with all controls in AUTOMATIC
- OPT-106A, Control Rod Exercise, is in progress
- OPT-106A, Section 8.2 has been completed for all Shutdown Banks and all Control Banks with exception of Control Bank D
- The fuel is fully conditioned
- ETP-106, Monthly RCCA Repositioning, is not being performed concurrently with this activity

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- EXERCISE Control Rods in Control Bank D per OPT-106A, Control Rod Exercise
- Per Shift Manager direction, WITHDRAW Control Bank D Rods per OPT-106A, Section 8.2
- RESTORE Automatic Rod Control when complete

Task Standard: WITHDREW Control Bank D Rods >10 steps, and ≤ 13 steps in accordance with OPT-106, Control Rod Exercise. Upon rod insertion, OBSERVED two dropped rods, TRIPPED the reactor and the turbine, and PERFORMED Immediate Operator Actions of EOP-0.0A, Reactor Trip or Safety Injection.

Ref. Materials: OPT-106A, Control Rod Exercise, Rev. 12.
OPT-106A-2, MODE 1 or 2 Control Rod Exercise Data Sheet, Rev. 2.
ABN-712, Rod Control System Malfunction, Rev. 11
EOP-0.0A, Reactor Trip or Safety Injection, Rev. 9

Validation Time: 15 minutes Time Critical: N/A Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________ Date: ____________

SIMULATOR SETUP

SIMULATOR OPERATOR:

INITIALIZE to IC-52 or any 97% power Initial Condition and ENSURE the following:

- **Insert malfunction to cause rods to drop when inward rod motion begins**
- **Prevent Main turbine from automatic trip**
- **VERIFY Control Bank D rod positions at 215 steps.**
- **VERIFY all other Control Rod Groups at 228 steps.**
- **VERIFY 1/1-RBSS, Control Rod Bank Select Switch is in the CBC position.**
- **Place TT06 on GTCC PWROPS and all points on scale**

NOTE: After each JPM, VERIFY 1/1-RBSS, Control Rod Bank Select Switch is in the CBC position prior to performance by the next candidate.

EXAMINER:

PROVIDE the examinee with a copy of:

- **OPT-106A, Control Rod Exercise (Procedure 1).**
- **OPT-106A-2, MODE 1 or 2 Control Rod Exercise Data Sheet completed up to Control Bank D (Form).**
- **When/If requested ABN-712, Rod Control System Malfunction (Procedure 2).**
- **When/If requested EOP-0.0A, Reactor Trip or Safety Injection (Procedure 3).**

√ - Check Mark Denotes Critical Step

START TIME:	

NOTE: Record section 8.2 data on Form OPT-106A-2.

NOTE: The following alarms may occur while performing this test. No response should be required for the alarm condition.

- "ANY CONTROL ROD BANK AT LO LMT" (6D-1.7)
- "ANY CONTROL ROD BANK AT LO-LO LMT" (6D-2.7)
- "DRPI ROD DEV" (6D-3.5)
- "QUADRANT PWR TILT" (6D-4.10)
- "CONTROL ROD BANK D FULL WTHDRWL" (6D-4.14)

Perform Step: 1 8.2 & 8.2.1	IF this test is being performed while in Mode 1 or 2, THEN PERFORM the following: • RECORD Pre-Test step counter demand position for each rod group.
Standard:	RECORDED pre-test step counter demand position of 215 steps for Control Bank D Rods Group 1 and Group 2 on Form OPT-106A-2.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 2√ 8.2.2	Place 1/1-RBSS, CONTROL ROD BANK SELECT in the position corresponding to the bank to be tested.
Standard:	PLACED Switch 1/1-RBSS, CONTROL ROD BANK SELECT Switch in the CBD, Control Bank D position.
Comment:	**SAT** ☐ **UNSAT** ☐

CAUTION:
- The following steps will cause a change in reactor power level and Tavg.
- If control rods are inadvertently pulled above 231 steps, rod motion should be stopped and step counters reset per SOP-702A.

Perform Step: 3 8.2.3 & 8.2.3.A	MOVE the bank being tested as follows: • IF the Bank being tested is greater than or equal to 220 AND <230 steps, THEN WITHDRAW the bank being tested to 230 steps as indicated on the step counter.
Standard:	OBSERVED Control Bank D Rods at 215 steps and MARKED step N/A
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 4
8.2.3 & 8.2.3.B.1)
	MOVE the bank being tested as follows:
	• IF the Bank being tested is less than 220 steps, THEN perform the following:
	  • The Shift Manager is to determine the initial direction of rod movement based on:
	    • Current rod position
	    • ΔI
	    • Current rod location in the AFD band
	    • Proximity to run-back limits
	    • Fuel conditioning / rod motion limits

Standard:	OBSERVED Cue Sheet and DETERMINED the Shift Manager has directed rod movement in the outward direction first.
Examiner Note:	**If asked report the Shift Manager has directed rod movement in the outward direction first.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**Examinee should recognize the effects on Reactor power and temperature as Control Rods are moved.**
Perform Step: 5√ 8.2.3 & 8.2.3.B.2)	MOVE the bank being tested as follows: • IF the Bank being tested is less than 220 steps, THEN perform the following: • MOVE the Bank being tested ≥10 AND <13 steps as indicated on the step counter.
Standard:	PLACED 1/1-FLRM, CONTROL ROD MOTION CONTROL Switch in the OUT position and WITHDREW Control Bank D Rods to a Bank position of 225 to 227 steps on both counters.
Examiner Note:	**1-ALB-6D, Window 4.14 – CONTROL ROD BANK D FULL WITHDRWL will alarm when Bank D rods reach 223 steps. If examinee identifies alarm as expected (prior to receiving alarm) then referencing the alarm response is not required.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 6 8.2.4	RECORD Initial step counter demand position for each rod group in the bank being tested.
Standard:	OBSERVED 1-SC-CBD1, CTRL BANK D GROUP 1 and 1-SC-CBD2, CTRL BANK D GROUP 2 Step Counter Demand Position and RECORDED Initial Position of Control Bank D Rod Groups on Form OPT-106A-2.
Comment:	**SAT** ☐ **UNSAT** ☐

Simulator Operator Note:	**When the applicant begins to insert Control Bank D Rods, Control Rod F10 will drop. Control Rod F6 will be linked to Control Rod F10's rod bottom light and will drop when illuminated.**

NOTE: If the controlling bank of rods is not returned to the original recorded position an adjustment of the Rod Bank Overlap Unit will be required (See Step 8.2.13).

Perform Step: 7√ 8.2.5	Move the bank being tested ≥ 10 AND < 13 steps in the opposite direction of movement in step 8.2.3.
Standard:	PLACED 1/1-FLRM, CONTROL ROD MOTION CONTROL Switch in the IN position and INSERTED Control Bank D Rods to a Bank position of 215 to 217 steps on both counters.
Examiner Note:	**Based on the CAUTION prior to Step 8.1 the Examinee should attempt to move the rods only the minimum of 10 steps if all position indications are OPERABLE.**
Comment:	**SAT** ☐ **UNSAT** ☐

Examiner Note:	**The following steps represent the Alternate Path for this JPM.**

CAUTION:
- IF any testing is being performed with a demand position indication inoperable (TS 3.1.7) THEN movement of 11 steps on the operating demand counter is required to ensure that both banks received a minimum demand of 10 steps.
- With all indications operable, minimum rod movement is desired (10 steps) in order to minimize reactivity changes.
- If one or more rods dropped OR one or more rods are misaligned by >/= 12 steps from their associated bank position during this test, respond per ABN-712, "Rod Control System Malfunction"
- If a runback (or any other event which requires rapid control rod insertion) occurs during the performance of OPT-106, it is recommended that control rods be returned to Automatic control as soon as possible. It is not necessary or desired to restore proper overlap prior to returning to automatic. Per TS 3.1.6, a LCOAR should be entered to ensure this adverse condition is corrected within the required time frame of 2 hours. (EV-CR-2011-001368-1)

Perform Step: 8 CAUTION	Operator observes 2 Control Rods drop and observes CAUTION prior to step 8.1: • If one or more rods dropped OR one or more rods are misaligned by ≥ 12 steps from their associated bank position during this test, respond per ABN-712, "Rod Control System Malfunction"
Standard:	OBSERVED CAUTION and REFERENCED ABN-712, ROD CONTROL SYSTEM MALFUNTION, Section 3.0, DROPPED OR MISALIGNED ROD IN MODE 1 OR 2.
Comment:	**SAT** ☐ **UNSAT** ☐

Examiner Note:	**The following steps are from ABN-712, Rod Control System Malfunction, Section 3.0, Dropped or Misaligned Rod in Mode 1 or 2.**
Perform Step: 9 3.3.1	VERIFY Number of Rods Misaligned from Step Counter by >12 steps - ≤ ONE
Standard:	VERIFIED Control Rods F6 and F10 have DROPPED, and REFERENCES Step 1RNO
Examiner Note:	**The operator may PERFORM Immediate Operator Actions of EOP-0.0A without referencing ABN-712**
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 10 3.3.1 RNO a)	IF two or more rods dropped, THEN TRIP Reactor AND GO TO EOP-0.0A
Standard:	VERIFIED Control Rods F6 and F10 have DROPPED and begins performing Immediate Operator Actions EOP-0.0A
Comment:	**SAT** ☐ **UNSAT** ☐

<u>Examiner Note:</u>	**The following steps are from EOP-0.0A and are performed from memory. These steps may be followed up with the procedure after performance.**

Perform Step: 11√
Steps 1, 1.a, & 1.b
	VERIFY Reactor Trip:
	• VERIFY the following:
	    • Reactor trip breakers – AT LEAST ONE OPEN
	    • Neutron flux – DECREASING
	• All control rod position rod bottom lights – ON

Standard:	At CB-07, PLACED 1/1-RTC, RX TRIP BKR Switch in TRIP and DETERMINED BOTH reactor trip breakers are OPEN, Neutron flux is DECREASING and All control rod positions lights are ON.
Comment:	**SAT** ☐ **UNSAT** ☐

<u>Examiner Note:</u>	**If required, inform the applicant he is currently the only RO present in the control room.**
Perform Step: 12 Step 2	Verify Turbine Tripped: • All HP turbine stop valves – CLOSED
Standard:	OBSERVED the TURBINE is NOT Tripped and goes to step 2 RNO
<u>Examiner Note:</u>	**A Safety Injection may occur due to the delay in tripping the turbine.**
Comment:	**SAT** ☐ **UNSAT** ☐

Examiner Note:	**The Turbine must be tripped MANUALLY**
Perform Step: 13√ Step 2 RNO	Manually Trip Turbine
Standard:	Manually TRIPPED the Turbine by DEPRESSING 1-TTSW, Turbine Trip pushbutton and OBSERVED all HP Turbine Stop Valves closed
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 14 Steps 3, 3.a, & 3.b	Verify Power To AC Safeguards Busses: • AC safeguards busses – AT LEAST ONE ENERGIZED • AC safeguards bus voltage – 6900 Volts (6500 – 7100 Volts) • AC safeguards busses – BOTH ENERGIZED
Standard:	OBSERVED Both AC safeguards busses 6900 Volts and stable
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**The following step must be performed anytime an SI Actuation has occurred. If the SI did NOT occur due to timing of the Turbine Trip then the Operator will perform EOP-0.0A, Step 4 RNO (Perform Step 16).**

Perform Step: 15
Step 4, 4.a, & 4.b
	Check SI Status:
	• CHECK if SI is actuated:
	    • SI actuation as indicated on the First Out Annunciator 1-ALB-6C
	    • SI actuated blue status light – ON
	• VERIFY Both Trains SI Actuated:
	    • SI Actuated blue status light – ON NOT FLASHING

Standard:	OBSERVED SI status.
Terminating Cue:	**If SI Actuated due to timing of the turbine trip then terminate the JPM and provide cue:** **Another operator will continue with the actions of EOP-0.0A** **IF SI did NOT Actuate, THEN continue to Perform Step 16 (Step 4.a RNO a.)**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**The following step will be performed if SI Actuation did NOT occur due to timing of the Turbine Trip.**
Perform Step: 16 Step 4.a RNO a.	Check if SI required:: • Steam Line Pressure less than 610 psig • Pressurizer Pressure less than 1820 psig • Containment Pressure greater than 3.0 psig • IF SI is NOT required, THEN go to EOS-0.1A, Reactor Trip Response, Step 1.
Standard:	OBSERVED SI status.
Terminating Cue:	**Another operator will continue with the actions of EOP-0.0A**
Comment:	**SAT** ☐ **UNSAT** ☐

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Unit 1 is operating at 97% with all controls in AUTOMATIC**
- **OPT-106A, Control Rod Exercise, is in progress**
- **OPT-106A, Section 8.2 has been completed for all Shutdown Banks and all Control Banks with exception of Control Bank D**
- **The fuel is fully conditioned**
- **ETP-106, Monthly RCCA Repositioning, is not being performed concurrently with this activity**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **EXERCISE Control Rods in Control Bank D per OPT-106A, Control Rod Exercise**
- **Per Shift Manager direction, WITHDRAW Control Bank D Rods per OPT-106A, Section 8.2**
- **RESTORE Automatic Rod Control when complete**

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

OPERATIONS TESTING MANUAL

FOR EMPLOYEE USE:		
DATE VERIFIED/INITIALS Today / JR	LATEST PCN/EFFECTIVE DATE /	

LEVEL OF USE:
CONTINUOUS USE

QUALITY RELATED

CONTROL ROD EXERCISE

PROCEDURE NO. OPT-106A

REVISION NO. 12

EFFECTIVE DATE: 9-3-14 1200

SURVEILLANCE PROCEDURE

PREPARED BY (Print): J.D. Stone Ext: 0564

TECHNICAL REVIEW BY (Print): EDITORIAL REVISION Ext: NA

APPROVED BY: Joe Ricks Date: 8/27/14
DIRECTOR, OPERATIONS

1.0 PURPOSE

This procedure satisfies shutdown and control rod operability testing for SR 3.1.4.2.

2.0 ACCEPTANCE AND REVIEW CRITERIA

2.1 Acceptance Criteria

2.1.1 Each rod not fully inserted in the core has moved at least 10 steps in one direction.

2.2 Review Criteria

None

3.0 DEFINITIONS/ACRONYMS

None

4.0 REFERENCES

4.1 Performance

4.1.1 Technical Specifications:

- 3.1.4, Rod Group Alignment Limits
- 3.1.7, Rod Position Indication
- 3.4.2, RCS Minimum Temperature for Criticality

4.1.2 IPO-002A, Plant Startup From Hot Standby

4.1.3 ETP-106, Monthly RCCA Repositioning

4.1.4 TDM-102, Reactor Control Rod Data

4.1.5 SOP-702A, Rod Control System

4.2 Development

4.2.1 FSAR 4.6, Functional Design of Reactivity Control Systems

4.2.2 FSAR 7.7, Control Systems Not Required for Safety

4.2.3 FSAR 3.9N.4, Control Rod Drive System (CRDS)

4.2.4 FSAR 15.4, Reactivity and Power Distribution Anomalies

4.2.5 Technical Manual CP-0001-067, Rod Control System

5.0 PRECAUTIONS, LIMITATIONS AND NOTES

5.1 Precautions

5.1.1 Withdrawal or insertion of control rods will cause a change in core reactivity. MONITOR plant conditions closely while performing this test.

5.1.2 Variations in turbine load and boron concentration should be avoided during the performance of this test.

5.1.3 If control rods are inadvertently pulled above 231 steps, rod motion should be stopped and step counters reset per SOP-702A.

5.2 Limitations

5.2.1 Each operating RCS loop average temperature (Tave) shall be ≥551°F per TS 3.4.2.

5.2.2 The Digital Rod Position Indication (DRPI) System and the Demand Position Indication System shall be OPERABLE per TS 3.1.7.

5.2.3 If a Rod Control System malfunction occurs while moving shutdown or control rod banks per this test, the applicability Note in rod insertion limit LCO 3.1.5 and LCO 3.1.6 indicating the LCO requirements are suspended during the performance of SR 3.1.4.2, is no longer applicable. TS Conditions for Rod Insertion Limits must be reviewed for applicability should the Rod Control System experience any malfunctions.

5.3 Notes

5.3.1 Fully withdrawn rod position is between 224 to 231 steps as determined by TDM-102.

5.3.2 There may be Fuel Conditioning Limits that apply to the magnitude and direction of rod motion, if necessary CONTACT Core Performance Engineering.

6.0 PREREQUISITES

☑ 6.1 Unit 1 is in MODE 1 or 2 at steady state operations, OR the unit is in startup (MODE 3) per IPO-002A.

6.2 The following alarms are clear OR have been evaluated for impact on performance of this test:

- ☑ "CONTROL ROD CTRL URGENT FAIL" (6D-1.6)
- ☑ "CONTROL ROD CTRL NON-URGENT FAIL" (6D-2.6)
- ☑ "DRPI URGENT FAIL" (6D-3.6)
- ☑ "QUADRANT PWR TILT" (6D-4.10)

☑ 6.3 Two (2) Operators may be used to perform this test which will reduce the time the rods are out of position and impact on plant parameters. One (1) Operator to move rods and read rod positions AND one (1) Operator to record data on the form.

7.0 TEST EQUIPMENT None

8.0 INSTRUCTIONS

NOTE: Record section 8.1 data on Form OPT-106A-1.

CAUTION:
- IF any testing is being performed with a demand position indication inoperable (TS 3.1.7) THEN movement of 11 steps on the operating demand counter is required to ensure that both banks received a minimum demand of 10 steps.
- With all indications operable, minimum rod movement is desired (10 steps) in order to minimize reactivity changes.
- If one or more rods dropped OR one or more rods are misaligned by >/= 12 steps from their associated bank position during this test, respond per ABN-712, "Rod Control System Malfunction"
- If a runback (or any other event which requires rapid control rod insertion) occurs during the performance of OPT-106, it is recommended that control rods be returned to Automatic control as soon as possible. It is not necessary or desired to restore proper overlap prior to returning to automatic. Per TS 3.1.6, a LCOAR should be entered to ensure this adverse condition is corrected within the required time frame of 2 hours. (EV-CR-2011-001368-1)

8.1 IF this test is being performed while rods are being withdrawn per IPO-002A, THEN RECORD the following:

N/A

- ☐ Initial step counter demand.

NOTE: DRPI indication is "SAT" if it indicates rod motion in the same direction as was demanded.

- ☐ DRPI position indication has changed for each rod withdrawn.
- ☐ Final rod position after withdrawal of ≥10 steps.

NOTE: Record section 8.2 data on Form OPT-106A-2.

NOTE: The following alarms may occur while performing this test. No response should be required for the alarm condition.

- "ANY CONTROL ROD BANK AT LO LMT" (6D-1.7)
- "ANY CONTROL ROD BANK AT LO-LO LMT" (6D-2.7)
- "DRPI ROD DEV" (6D-3.5)
- "QUADRANT PWR TILT" (6D-4.10)
- "CONTROL ROD BANK D FULL WTHDRWL" (6D-4.14)

8.2 IF this test is being performed while in MODE 1 or 2, THEN PERFORM the following:

☐ 8.2.1 RECORD Pre-Test step counter demand position for each rod group.

8.2.2 PLACE 1/1-RBSS, CONTROL ROD BANK SELECT in the position corresponding to the bank to be tested:

SWITCH POSITION BANK TESTED

- ☑ SBA Shutdown Bank A
- ☑ SBB Shutdown Bank B
- ☑ SBC Shutdown Bank C
- ☑ SBD Shutdown Bank D
- ☑ SBE Shutdown Bank E
- ☑ CBA Control Bank A
- ☑ CBB Control Bank B
- ☑ CBC Control Bank C
- ☐ CBD Control Bank D

CAUTION:	• The following steps will cause a change in reactor power level and Tavg. • If control rods are inadvertently pulled above 231 steps, rod motion should be stopped and step counters reset per SOP-702A.

8.2.3 MOVE the bank being tested as follows:

☐ A. IF the Bank being tested is greater than or equal to 220 AND <230 steps, THEN WITHDRAW the bank being tested to 230 steps as indicated on the step counter.

B. IF the Bank being tested is less than 220 steps, THEN PERFORM the following:

☐ 1) The Shift Manager is to determine the initial direction of rod movement based on:

- current rod position
- ΔI
- current location in the AFD band
- proximity to run-back limits
- fuel conditioning / rod motion limits

☐ 2) MOVE the Bank being tested ≥10 AND <13 steps as indicated on the step counter.

☐ 8.2.4 RECORD Initial step counter demand position for each rod group in the bank being tested.

NOTE:	If the controlling bank of rods is not returned to the original recorded position an adjustment of the Rod Bank Overlap Unit will be required (See Step 8.2.13).

☐ 8.2.5 MOVE the bank being tested ≥10 AND <13 steps in the opposite direction of movement in step 8.2.3 (or INWARD if not moved in 8.2.3).

NOTE:	DRPI indication is "SAT" if it indicates rod motion in the same direction as was demanded.

8.2.6 VERIFY:

☐ • all rods in the bank being tested have moved by recording Test Position step counter demand

☐ • DRPI position indication has changed for each rod in the bank.

NOTE: IF performing this test concurrently with ETP-106, THEN the rods may be repositioned accordingly.

☐ 8.2.7 RETURN the bank being tested to Pre-test position (step 8.2.1) OR as directed by the Shift Manager.

☐ 8.2.8 RECORD the Final step counter demand position for each rod group in the bank being tested.

☐ 8.2.9 REPEAT steps 8.2.2 through 8.2.8 for each bank that is NOT fully inserted.

☐ 8.2.10 PLACE 1/1-RBSS, CONTROL ROD BANK SELECT in MAN.

8.2.11 VERIFY the following alarms are clear OR EVALUATE for current plant conditions:

- ☐ "CONTROL ROD CTRL URGENT FAIL" (6D-1.6)
- ☐ "ANY CONTROL ROD BANK AT LO LMT" (6D-1.7)
- ☐ "CONTROL ROD CTRL NON-URGENT FAIL" (6D-2.6)
- ☐ "ANY CONTROL ROD BANK AT LO-LO LMT" (6D-2.7)
- ☐ "DRPI ROD DEV" (6D-3.5)
- ☐ "DRPI URGENT FAIL" (6D-3.6)
- ☐ "DRPI NON-URGENT FAIL" (6D-4.6)
- ☐ "QUADRANT PWR TILT" (6D-4.10)

8.2.12 IF AUTO rod control is desired, THEN PERFORM the following:

☐ A. VERIFY alarm "LO TURB PWR ROD WTHDRWL BLK C-5" is clear (PCIP-2.4).

☐ B. ENSURE Tavg and Tref are within 1°F of each other.

☐ C. PLACE 1/1-RBSS, CONTROL ROD BANK SELECT in AUTO.

☐ 8.2.13 ENSURE the P/A Converter and the Bank Overlap Unit are displaying the correct values for current rod positions. IF necessary, REFER to SOP-702A to reset.

9.0 RESTORATION

None

10.0 ATTACHMENTS/FORMS

10.1 Attachments None

10.2 Forms

10.2.1 OPT-106A-1, Mode 3 Control Rod Exercise Data Sheet

10.2.2 OPT-106A-2, Mode 1 or 2 Control Rod Exercise Data Sheet

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1 AND 2

ABNORMAL CONDITIONS PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ________/______ LATEST PCN/EFFECTIVE DATE ________/________

QUALITY RELATED

ROD CONTROL SYSTEM MALFUNCTION

PROCEDURE NO. ABN-712

REVISION NO. 11

EFFECTIVE DATE: 6-21-16 1200

PREPARED BY (Print): J.D. STONE Ext: 0564

TECHNICAL REVIEW BY (Print): EDITORIAL REVISION Ext: NA

APPROVED BY: Joe Ricks for D. McGaughey Date: 6/15/16
DIRECTOR, OPERATIONS

1.0 APPLICABILITY

This procedure describes the actions for a rod control or indication malfunction while in MODE 1, 2, 3, 4, or 5.

- Section 2.0 - Abnormal Rod Control Response in MODE 1 or 2
- Section 3.0 - Dropped or Misaligned Rod in MODE 1 or 2
- Section 4.0 - Digital Rod Position Indication Malfunction
- Section 5.0 - Rod Insertion Limit Monitor or P/A Converter Malfunction
- Section 6.0 - Control Bank D Step Counter Greater than 231 Steps
- Section 7.0 - Bank Demand Step Counter Malfunction
- Section 8.0 - Rod Malfunction in MODE 3, 4 or 5 (Abnormal Rod Control Response, Dropped or Misaligned Rod)
- Section 9.0 - Rod Drive MG Malfunction

3.0 DROPPED OR MISALIGNED ROD IN MODE 1 OR 2

3.1 Symptoms

a. Annunciator Alarms

- PR CHAN DEV (6D-3.4)
- DRPI ROD DEV (6D-3.5)
- ANY ROD AT BOT (6D-3.7)
- ≥2 ROD AT BOT (6D-4.7)
- QUADRANT PWR TILT (6D-4.10)

b. Plant Indications

- Plant parameters changing abnormally during rod position changes

NOTE:
- A dropped rod will distort the symmetrical flux distribution of the reactor core. This distortion will be reflected as a deviation in the power range and N16 indications monitored by OPT-102A/B (SR 3.3.1.1.2.a; 3.3.1.1.2.b.;3.3.1.1.6; 3.3.1.1.7). The power range and N16 instrumentation need not be declared inoperable if indications were within the required deviation prior to the event and no other influence has occurred. (SMF-2007-003427)
- For the 12 hour shifty surveillance while in the abnormal condition of a dropped rod, an assessment should be performed that the channels are indicating as expected for the condition of an asymmetrical flux pattern. Since the dropped rod may cause the channels to deviate beyond the normal Channel Check criteria, an assessment is required that the channels are as expected for the plant condition. If required, additional resources (e.g. Core Performance Engineering) may be consulted to assist with the assessment. (SMF-2007-003427)

- NIS Power Range instruments power or AFD indications disagree
- DRPI Rod Bottom Light(s) lit for rods which should be withdrawn
- DRPIs in a bank disagree by greater than 12 steps
- DRPI disagrees with its group step counter by greater than 12 steps

3.2 Automatic Actions

- Possible Reactor trip
- Automatic control rod motion

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 1 VERIFY Number of Rods Misaligned from Step Counter by >12 steps - ≤ ONE	a) IF two or more rods **dropped**, THEN TRIP Reactor AND GO TO EOP-0.0A/B. b) Within 1 hour, VERIFY SDM OR INITIATE boration to restore SDM. c) Within 6 hours, PLACE unit in HOT STANDBY per IPO-003A/B (TS 3.1.4).

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 2 Check Reactor - CRITICAL AND Less than or equal to 100% on highest reading NI AND No Reactor Startup in progress	REDUCE load to less or equal to 1100 MW. IF rod(s) misaligned greater than 12 steps during Reactor startup, THEN PERFORM the following: a. Within 1 hour, INSERT ALL Control Banks to Control Bank Offset Position. b. LOG entry into MODE 3. c. INITIATE Tracking LCOAR, as necessary (TS 3.1.4). d. Within 1 hour AND once per 12 hours thereafter, ENSURE adequate Shutdown Margin per TS 3.1.4: 1) PERFORM OPT-301. 2) DOCUMENT per OPT-102A/B. e. INITIATE Condition Report per STA-421. f. WHEN all RCCAs are returned to operable status, THEN PERFORM the following: 1) REFERENCE AND POSITION affected rod(s) per IPO-002A/B. 2) DOCUMENT rod operability per OPT-106A/B.

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 3 ENSURE 1/u-RBSS, CONTROL ROD BANK SELECT - NOT IN AUTO.	
☐ 4 VERIFY Reactor - STABLE • Tave-Tref - WITHIN 1°F • Reactor Power - STABLE	CONTROL Tave AND Reactor Power by controlling the following, as necessary: • Turbine Power • Boration • Dilution • Steam dumps • Steam Generator Atmospheric Relief Valves
☐ 5 VERIFY AXIAL FLUX DIFFERENCE (AFD) - WITHIN LIMITS	RESTORE ΔFlux to within limits OR REDUCE power within 30 minutes. REFER to TS 3.2.3
☐ 6 VERIFY "QUADRANT PWR TILT" Alarm (6D-4.10) - DARK	IF Reactor Power is greater than 50% RTP, THEN PERFORM OPT-302 (TS 3.2.4).
☐ 7 Within ONE Hour, DETERMINE Cause of Abnormal Rod Position.	ENSURE TS 3.1.4 requirements implemented per LCOAR.

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 8 CHECK Plant Parameters Indicate ACTUAL Dropped or Misaligned Rod: • Tave • AFD • QPTR • NIS • REVIEW Plant Computer CET map for any abnormal indications.	IF DRPI malfunction indicated, THEN GO TO Section 4.0, this procedure.
9 PERFORM the following: ☐ • INITIATE Condition Report per STA-421. ☐ • DIRECT Chemistry to perform shiftly analysis for fuel defects until plant restored to stable conditions.	

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE:
- Either of two realignment methods may be used. The DRPI method is less accurate but may allow quicker realignment with less rod movement. The referencing method is more accurate but requires stepping affected rod full out and may have more adverse effect on flux shape.
- A rod may be recovered within the first 6 hours of the event with no restrictions on rod recovery rate or plant operation (EVAL-2006-0003933-04).

☐ 10 CONTACT Reactor and System Engineering and Plant Management
[C] prior to realigning Rods.

- DETERMINE if any rod recovery restrictions apply.
- DETERMINE recovery method.

☐ 11 Within 1 Hour AND Once per 12 Hours Thereafter, PERFORM OPT-301 to Verify Shutdown Margin (TS 3.1.4).

☐ 12 REDUCE Turbine and Reactor Power to Level at which Control Banks are LESS THAN OR EQUAL TO Position Prior to Transient
OR
to Level Sufficient to Withdraw Affected Rod, as determined by Engineering.

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION: The affected rod(s) shall be realigned to within ±12 steps of group step counter demand position within 1 hour or requirements of Tech Spec 3.1.4 implemented (LCOAR).

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 13 VERIFY DRPI Realignment Method Chosen.	GO TO step 16 for referencing realignment method.
☐ 14 TRANSFER 1/u-RBSS, CONTROL ROD BANK SELECT, to the affected bank.	

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION:
- Affected rod withdrawal should only be performed after fuel conditioning requirements have been met unless approved by Engineering.
- Do NOT withdraw an RCCA that has been misaligned for greater than 6 hours during power operation without Engineering guidance.

Note:
- The last movement of affected rod should be in the SAME direction as the last movement of affected group.
- When recovering a dropped rod using the DRPI method the dropped rod should be moved outward to the next DRPI step up vice in so as not to drive the dropped rod further into the core. Positive reactivity will be added during recovery.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
15 RESTORE Rod to OPERABLE Status by Realigning as follows within 1 Hour:	ENSURE TS 3.1.4 requirements implemented per LCOAR.
☐ a. RECORD positions for affected rod: Affected Rod (DRPI) _____ Bank (DRPI) _____ Group 1 step counter _____ Group 2 step counter _____	

"Step continued next page"

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION: Do NOT allow P/A Converter Auto-Manual selector switch to spring return to automatic until directed by this procedure.

15 ☐ b. IF restoring a Control Bank rod,
THEN
Locally POSITION AND
MAINTAIN P/A Converter
Auto-Manual selector switch
(SFGD 832 Rm u-096) - MANUAL

☐ c. MOVE affected group outward to the desired DRPI Light

CAUTION: Do NOT make any changes in plant operations during realignment of the affected rod that would require a change in bank position.

☐ d. PLACE all lift coil disconnect switches for affected bank, groups 1 AND 2, EXCEPT for affected rod to the UP (disconnected) position.

"Step continued next page"

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE:
- When moving affected rod, a CONTROL ROD CTRL URGENT FAIL alarm will be received in control room and at power cabinet containing the other group of affected bank. This is normal and will prevent the other group's step counter from operating.
- At low RCS boron concentration, excessive boration may delay return to desired power level after rod recovery.

15 ☐ e. WHEN moving the affected rod for realignment,
THEN
PERFORM the following:

1) MAINTAIN Tave within 2°F of Tref by controlling the following, as necessary:
   - Turbine Power
   - Steam Dumps
   - Boration
   - Dilution

2) VERIFY that only the affected rod is moving.

3) ENSURE last movement of affected rod is in same direction as last movement of affected group.

☐ f. WITHDRAW the affected rod in controlled increments until aligned with its group by DRPI indication.

"Step continued next page

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
15 ☐ g. PLACE all lift coil disconnect switches to the DOWN (connected) position.	

CAUTION: Resetting the Urgent Failure Alarm removes the reduced current applied to movable and stationary grippers. IF cause of alarm has NOT been corrected, THEN resetting alarm may result in dropping rod(s).

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ h. VERIFY Rod Control Urgent Failure alarm - CLEAR	CLEAR the Rod Control Urgent Failure alarm as follows: ☐ a. ENSURE only lift reg white light on designated circuit card in affected cabinet (See ALB-6D 1.6 logic diagram) - LIT ☐ b. DEPRESS 1/u-RCAR, CONTROL ROD CTRL ALARM RESET ☐ c. ENSURE ALL white lights on designated circuit card in affected cabinet (See ALB-6D 1.6 logic diagram) - DARK
☐ i. RESTORE affected bank to the DRPI position recorded in step15a.	
☐ j. RESET affected bank demand step counters to the values recorded in Step 15a.	

"Step continued next page"

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
15 ☐ k. IF operated in step 15b, THEN PLACE P/A Converter Auto-Manual selector switch - AUTO	
☐ l. PLACE 1/u- RBSS CONTROL ROD BANK SELECT to MANUAL.	
☐ m. GO TO Step 17.	

CAUTION: Do NOT make any changes in plant operation during realignment that would require a change in bank position.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
16 PERFORM Referencing Realignment Method as follows:	
☐ a. TRANSFER 1/u-RBSS, CONTROL ROD BANK SELECT to affected bank.	

"Step continued next page"

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE: Rod Groupings are listed on Attachment 1.

16 ☐ b. RECORD positions for affected rod:

Affected Rod (DRPI) _____

Bank (DRPI) _____

Group 1 step counter _____

Group 2 step counter _____

☐ c. PLACE all lift coil disconnect switches for affected bank, groups 1 AND 2, EXCEPT for affected rod - ROD DISCONNECTED

[C] ☐ d. WHILE performing the following steps, VERIFY that ONLY affected rod moves.

☐ e. RESET affected rod group demand step counter to zero steps.

"Step continued next page"

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE: At low RCS boron concentration, excessive boration may delay return to desired power level after rod recovery.

☐ f. MAINTAIN Tave within 2°F of Tref by controlling the following, as necessary:

- Turbine Power
- Steam Dumps
- Boration
- Dilution

NOTE: When moving affected rod, a CONTROL ROD CTRL URGENT FAIL alarm will be received in control room and at power cabinet containing the other group of affected bank. This is normal and will prevent the other group' step counter from operating.

16 ☐ g. RESET P/A converter for affected bank - ZERO per SOP-702A/B

☐ h. Over a 15 or 30 minute period OR as specified by Engineering, WITHDRAW affected rod until operating step counter is at 232 steps.

☐ I. ADJUST affected step counter to 231 steps.

"Step continued next page"

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
16 ☐ j. INSERT rod to position recorded in Step 16b, affected Group Step Counter.	
☐ k. VERIFY P/A converter for affected bank reads value recorded in Step 16b Group Step Counter.	Manually RESET P/A converter per SOP-702A/B to value recorded in step 16b Group Step Counter.
☐ l. VERIFY affected rod is at same position as its bank (DRPI).	
☐ m. PLACE all lift coil disconnect switches - ROD CONNECTED	
☐ n. TRANSFER 1/u-RBSS, CONTROL ROD BANK SELECT - MANUAL.	

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION: Resetting the Urgent Failure Alarm removes the reduced current applied to movable and stationary grippers. IF cause of alarm has NOT been corrected, THEN resetting alarm may result in dropping rod(s).

17 CLEAR the Rod Control Urgent Failure alarm as follows:

- ☐ a. ENSURE only lift reg white light on designated circuit card in affected cabinet (See ALB-6D 1.6 logic diagram) - LIT
- ☐ b. DEPRESS 1/u-RCAR, CONTROL ROD CTRL ALARM RESET
- ☐ c. ENSURE ALL white lights on designated circuit card in affected cabinet (See ALB-6D 1.6 logic diagram) - DARK

☐ 18 ADJUST Tave to within 1°F of Tref

☐ 19 PLACE 1/u-RBSS CONTROL ROD BANK SELECT - AUTO if desired

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE: Verification of OPT-106A/B requirement may be satisfied by documenting rod motion during realignment, at discretion of Shift Manager.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 20 VERIFY Rod Restored to OPERABLE status WITHIN 1 HOUR from Time Rod Was Misaligned: • PERFORM OPT-106A/B OR • DOCUMENT rod motion greater than or equal to 10 steps in one direction in Unit Log.	INITIATE actions of TS 3.1.4B AND INITIATE LCOAR.
☐ 21 VERIFY Rod Position Indicators - MATCH ACTUAL POSITIONS • DRPI • Step Counters • P/A Converter • Bank Overlap Unit • Plant Computer	CONSULT Engineering as necessary to determine actual position(s) AND ADJUST affected indicators to agree (REFER to SOP-702A/B).

3.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
22 VERIFY Rod Position Deviation Monitor - OPERABLE	INITIATE LCOAR (TS 3.1.4, 3.1.7, TR 13.1.37).
☐ a. CHECK "DRPI ROD DEV" (6D-3.5) alarm matches actual conditions: • ALL shutdown rods greater than 210 steps AND ALL DRPIs within ±12 steps of their group position - WINDOW DARK • Any shutdown rod less than or equal to 210 steps OR any DRPI greater than or equal to ±12 steps from its group demand position - WINDOW LIT	
☐ b. CHECK "DRPI URGENT FAIL" (6D-3.6) alarm - DARK	
☐ 23 REFER to EPP-201.	
☐ 24 INITIATE a Condition Report per STA-421, as applicable.	

END OF SECTION

COMANCHE PEAK NUCLEAR POWER PLANT
UNIT 1
EMERGENCY RESPONSE GUIDELINES

FOR EMPLOYEE USE:
DATE VERIFIED INITIALS ______/______ LATEST PCN/EFFECTIVE DATE PCN-2 / 11/29/16 1200

QUALITY RELATED

REACTOR TRIP OR SAFETY INJECTION

PROCEDURE NO. EOP-0.0A

REVISION NO. 9

EFFECTIVE DATE: 11/03/15 1200

PREPARED BY (Print): TONY SIROIS **EXT:** 6635

TECHNICAL REVIEW BY (Print): BART SMITH / DAVE WATSON **EXT:** 6220 / 5451

APPROVED BY: JOHN RASMUSSEN FOR DEE McGAUGHEY **DATE:** 09/23/15
DIRECTOR, OPERATIONS

EOP-0.0A REV. 9 **REACTOR TRIP OR SAFETY INJECTION**

MAJOR ACTION CATEGORIES

- A. VERIFY AUTO ACTIONS
- B. IDENTIFY RECOVERY PROCEDURE
- C. SHUTDOWN UNNECESSARY EQUIPMENT AND CONTINUE TRYING TO IDENTIFY APPROPRIATE RECOVERY PROCEDURE

A.

1. VERIFY REACTOR TRIP
2. VERIFY TURBINE TRIP
3. VERIFY POWER TO AC SAFEGUARDS BUSSES
4. CHECK SI STATUS
5. INITIATE PROPER SAFEGUARDS EQUIPMENT OPERATION PER ATTACHMENT 2
6. * VERIFY AFW ALIGNMENT
7. * VERIFY CONTAINMENT SPRAY NOT REQUIRED
8. * CHECK IF MAIN STEAMLINES SHOULD BE ISOLATED

B.

9. * CHECK RCS TEMPERATURE
10. CHECK PRZR VALVE STATUS
11. CHECK IF RCPs SHOULD BE STOPPED
12. CHECK IF ANY SG IS FAULTED
13. CHECK IF SG TUBES ARE NOT RUPTURED
14. CHECK IF RCS IS INTACT
15. CHECK IF ECCS FLOW SHOULD BE REDUCED
16. * INITIATE MONITORING OF CRITICAL SAFETY FUNCTION STATUS TREES ON SPDS
17. * CHECK SG LEVELS
18. CHECK SECONDARY RADIATION - NORMAL
19. CHECK AUXILIARY AND SAFEGUARDS BUILDING RADIATION – NORMAL (GRID 4)
20. CHECK PRT CONDITIONS

C.

21. CHECK IF DIESEL SHOULD BE EMERGENCY STARTED
22. RESET SI
23. RESET SI SEQUENCERS
24. RESET CONTAINMENT ISOLATION PHASE A AND PHASE B
25. ESTABLISH INSTRUMENT AIR AND NITROGEN TO CONTAINMENT
26. * CHECK IF RHR PUMPS SHOULD BE STOPPED
27. * CHECK IF DIESEL GENERATORS SHOULD BE STOPPED
28. RETURN TO STEP 9

- FRS-0.1A, RESPONSE TO NUCLEAR POWER GENERATION/ATWT
- ABN-601, RESPONSE TO A 138/345KV SYSTEM MALFUNCTION OR ABN-602 RESPONSE TO A 6900/480 VOLT SYSTEM MALFUNCTION
- ECA-0.0A, LOSS OF ALL AC POWER
- EOS-0.1A, REACTOR TRIP RESPONSE
- FRH-0.1A, RESPONSE TO LOSS OF SECONDARY HEAT SINK
- EOP-1.0A, LOSS OF REACTOR OR SECONDARY COOLANT
- EOP-2.0A, FAULTED STEAM GENERATOR ISOLATION
- EOP-3.0A, STEAM GENERATOR TUBE RUPTURE
- EOP-1.0A, LOSS OF REACTOR OR SECONDARY COOLANT
- EOS-1.1A, SAFETY INJECTION TERMINATION
- EOP-3.0A, STEAM GENERATOR TUBE RUPTURE
- ECA-1.2A, LOCA OUTSIDE CONTAINMENT
- EOP-1.0A, LOSS OF REACTOR OR SECONDARY COOLANT
- ABN-601, RESPONSE TO A 138/345KV SYSTEM MALFUNCTION OR ABN-602 RESPONSE TO A 6900/480 VOLT SYSTEM MALFUNCTION

*** CONTINUOUS ACTION STEP**

A. PURPOSE

This procedure provides actions to verify proper response of automatic protection systems following manual or automatic actuation of a reactor trip or safety injection, to assess plant conditions, and to identify the appropriate recovery procedure.

B. APPLICABILITY

This procedure is applicable for initiating events occurring in MODES 1, 2 and 3 GREATER THAN OR EQUAL TO 1000 PSIG. Using this procedure when not in these modes requires a step by step evaluation to determine if the required action is still applicable to current plant conditions.

C. SYMPTOMS OR ENTRY CONDITIONS

1) The following are symptoms that require a reactor trip:

- 2/4 Neutron Flux power ranges greater than 109%
- 2/4 Neutron Flux power ranges greater than 25% (Below P-10 permissive)
- 2/4 Neutron Flux rate trip lights as indicated on NIS cabinets (POSITIVE RATE TRIP)
- 1/2 Neutron Flux source ranges greater than 10^5 CPS (Below P-6 permissive)
- 1/2 Neutron Flux intermediate ranges greater than Amps approximately 25% (Above P-6 permissive and below P-10 permissive)
- 2/4 N-16 power exceed indicated Overtemperature N-16 setpoint
- 2/4 N-16 power greater than 112%
- Pressurizer pressures less than 1880 psig (Above P-7 permissive)
- 2/4 Pressurizer pressures greater than 2385 psig
- 2/3 Pressurizer water levels greater than 92% (Above P-7 permissive)
- 2/3 Reactor coolant loop flows less than 90% on 1/4 loops (Above P-8 permissive)
- 2/3 Reactor coolant loop flows less than 90% on 2/4 loops (Above P-7 and less than P-8 permissives)
- 2/4 Steam Generator levels less than 38% of Narrow Range on 1/4 steam generators
- 2/3 Turbine trip oil pressures less than 60 psig or 4/4 stop valves closed (Above P-9 permissives)
- Any Safety Injection signal
- Any First Out Annunciator lit
- Reactor trip logic met as indicated on the trip status logic bistable (TSLB) lights
- Both SSPS General Warning alarms in (1-ALB-6D, 1-5 and 2-5)

2) The following are symptoms of a reactor trip:

   - Any reactor trip first out annunciator lit.
   - Rapid decrease in neutron flux level.
   - Shutdown and control rods inserted.

3) The following are symptoms that require a safety injection:

   - 2/3 containment pressures greater than 3.0 psig.
   - 2/4 pressurizer pressures less than 1820 psig.
   - 2/3 steam line pressures less than 610 psig in any steam line.

4) The following are symptoms of a safety injection:

   - SI annunciator lit (PCIP or First Out).
   - ECCS pumps running.
   - Diesel Generators running.
   - Non-essential electrical power load shedding.

D. <u>ATTACHMENTS</u>

Attachment 1.A, Foldout For EOP-0.0A Reactor Trip Or Safety Injection

Attachment 1.B, EOP-0.0A Continuous Action Steps

Attachment 1.D, Safeguards Signal Reset Sequence

Attachment 2, Safety Injection Actuation Alignment

Attachment 3, SI Sequencer

Attachment 4, Phase A Isolation

Attachment 5, Containment Ventilation Isolation

Attachment 6, Containment Spray/Phase B Isolation

Attachment 7, Safety Injection Actuation

Attachment 8, Load Shedding

Attachment 9, Post Event System Realignment

Attachment 10, Bases

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
1	Verify Reactor Trip:	
	a. Verify the following: • Reactor trip breakers - AT LEAST ONE OPEN -AND- • Neutron flux - DECREASING	a. Manually trip reactor from both trip switches. IF reactor will not trip, THEN momentarily de-energize 480V normal switchgear 1B3 AND 1B4. IF reactor NOT tripped, THEN go to FRS-0.1A, RESPONSE TO NUCLEAR POWER GENERATION/ATWT, Step 1.
	b. All control rod position rod bottom lights - ON	
2	Verify Turbine Trip: • All HP turbine stop valves - CLOSED	Manually trip turbine. IF the turbine will NOT trip, THEN pull-out all EHC fluid pumps. IF turbine still NOT tripped, THEN close or verify closed main steamline isolation valves.
3	Verify Power To AC Safeguards Busses:	
	a. AC safeguards busses - AT LEAST ONE ENERGIZED • AC safeguards bus voltage- 6900 Volts(6500-7100 Volts)	a. Go to ECA-0.0A, LOSS OF ALL AC POWER, Step 1.
	b. AC safeguards busses - BOTH ENERGIZED	b. Restore power to de-energized AC safeguards bus per ABN-601, RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION or ABN-602, RESPONSE TO A 6900/480 VOLT SYSTEM MALFUNCTION when time permits.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
4	Check SI Status:	
	a. Check If SI Is Actuated: • SI actuation as indicated on the First Out Annunciator 1-ALB-6C • SI Actuated blue status light - ON	a. Check if SI is required: • Steam Line Pressure less than 610 psig. • Pressurizer Pressure less than 1820 psig. • Containment Pressure greater than 3.0 psig. <u>IF</u> SI is required, <u>THEN</u> manually actuate SI from either handswitch. <u>IF</u> SI is <u>NOT</u> required, <u>THEN</u> go to EOS-0.1A, REACTOR TRIP RESPONSE, Step 1.
	b. Verify Both Trains SI Actuated: • SI Actuated blue status light - ON <u>NOT</u> FLASHING	b. Manually Actuate SI.

<u>CAUTION</u>: A Safety Injection actuation will affect normal egress from the Containment Building. Attachment 9 of this procedure provides instructions to evacuate personnel from the Containment during a Safety Injection actuation.

<u>NOTE</u>: Attachment 2 is required to be completed before FRGs are implemented unless directed by this procedure.

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
5	Initiate Proper Safequards Equipment Operation Per Attachment 2	

MODE 1 OR 2 CONTROL ROD EXERCISE DATA SHEET

6.0 PREREQUISITES MET JR
INITIALS

		STEP COUNTER DEMAND			
		PRE-TEST POSITION (8.2.1)	INITIAL POSITION (8.2.4)	TEST POSITION (8.2.6)	FINAL POSITION (8.2.8)
8.2	SHUTDOWN BANK A GROUP 1				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	SHUTDOWN BANK A GROUP 2				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	SHUTDOWN BANK B GROUP 1				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	SHUTDOWN BANK B GROUP 2				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	SHUTDOWN BANK C GROUP 1				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A

MODE 1 OR 2 CONTROL ROD EXERCISE DATA SHEET

		STEP COUNTER DEMAND			
		PRE-TEST POSITION (8.2.1)	INITIAL POSITION (8.2.4)	TEST POSITION (8.2.6)	FINAL POSITION (8.2.8)
8.2	SHUTDOWN BANK D GROUP 1				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	SHUTDOWN BANK E GROUP 1				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	CONTROL BANK A GROUP 1				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	CONTROL BANK A GROUP 2				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	CONTROL BANK B GROUP 1				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A

MODE 1 OR 2 CONTROL ROD EXERCISE DATA SHEET

		STEP COUNTER DEMAND			
		PRE-TEST POSITION (8.2.1)	INITIAL POSITION (8.2.4)	TEST POSITION (8.2.6)	FINAL POSITION (8.2.8)
8.2	CONTROL BANK B GROUP 2				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	CONTROL BANK C GROUP 1				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	CONTROL BANK C GROUP 2				
	STEP COUNTER	228	230	220	228
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	CONTROL BANK D GROUP 1				
	STEP COUNTER	______	______	______	______
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A
	CONTROL BANK D GROUP 2				
	STEP COUNTER	______	______	______	______
	DRPI MOVEMENT	N/A	N/A	SAT / UNSAT	N/A

ACCEPTANCE CRITERIA

Each rod not fully inserted in the core shall be determined to be operable by movement of at least ten (10) steps in any one direction.

MODE 1 OR 2 CONTROL ROD EXERCISE DATA SHEET

COMMENTS/DISCREPANCIES: ______________________

CORRECTIVE ACTIONS: ______________________

PERFORMED BY: ______________________ DATE: Today
SIGNATURE

REVIEWED BY: ______________________ DATE: __________
OPERATIONS MANAGEMENT

Facility: CPNPP JPM # NRC S-2 Task # RO1305 K/A # 004 A2.07 3.4 / 3.7 SF-2

Title: Isolate Leakage and Establish Excess Letdown

Examinee (Print): ____________________

Testing Method:

Simulated Performance:	______	Classroom:	______
Actual Performance:	X	Simulator:	X
Alternate Path:	X	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Unit 1 is in MODE 1
- The crew has determined that a 15 gpm Reactor Coolant System (RCS) leak exists.
- Actions of ABN-103, Excessive Reactor Coolant Leakage are in progress.
- RCS Auto Makeup has been occurring approximately every 13 minutes.

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- Continue with efforts to identify the source of the RCS leak by performing ABN-103, Excessive Reactor Coolant Leakage Step 2.3.8.

Task Standard: UTILIZED ABN-103, Excessive Reactor Coolant Leakage and DIAGNOSED the RCS leak in the Chemical and Volume Control System. ISOLATED the leak per ABN-103, Step 2.3.8 RNO. PLACED Excess Letdown in service per SOP-103A, Chemical and Volume Control System. MAINTAINED Excess Letdown outlet temperature less than 175°F.

Ref. Materials: ABN-103, Excessive Reactor Coolant Leakage, Rev. 10
SOP-103A, Chemical and Volume Control System, Rev. 18

Validation Time: 13 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ______________

SIMULATOR SETUP

SIMULATOR OPERATOR:
INITIALIZE to IC-46

OR

INITIALIZE to IC-18 or any at power Initial Condition and PERFORM the following:

- **Insert Malfunction CV14 at 15 gpm.**
- **Allow simulator to run for approximately 5 minutes.**

EXAMINER:
PROVIDE the examinee with a copy of:

- **ABN-103, Excessive Reactor Coolant Leakage, Section 2.0, Excessive Reactor Coolant Leakage, Step 2.3.8 (Procedure 1).**
- **When requested SOP-103A, Chemical and Volume Control System, Section 5.5.3, Placing Excess Letdown in Service (Procedure 2).**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from ABN-103.**
Perform Step: 1 2.3.8a	Check letdown and normal charging for leakage: • Area Radiation Monitor in vicinity of letdown AND charging – NORMAL • PPA121, HRAM PIPE PENET N(S). 810 (1-RE-6259B)
Standard:	CHECKED PC-11 and DETERMINED Area Radiation Monitors Normal.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2 2.3.8b	Check letdown and normal charging for leakage: • FFL160, FAILED FUEL (1-RE-406) - DOES NOT INDICATE LOSS OF FLOW
Standard:	CHECKED PC-11 and DETERMINED FFL160 Normal.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3 2.3.8c	Check letdown and normal charging for leakage: • VERIFY VCT level – NORMAL
Standard:	DETERMINED VCT level NOT Normal.
Examiner Note:	**Examinee may enter the RNO from this step or the next step.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4 2.3.8d	Check letdown and normal charging for leakage: • VERIFY RCS Makeup Flow and makeup intervals - NORMAL.
Standard:	DETERMINED Makeup Flow and intervals NOT Normal.
Examiner Note:	**Examinee may enter the RNO from this step or the previous step.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 5 2.3.8 RNO 1)	PERFORM the following: • NOTIFY Radiation Protection of affected areas.
Standard:	NOTIFIED Radiation Protection that an RCS leak exists outside Containment in Unit 1 Safeguards Building.
Examiner Cue:	**RP has been notified of an RCS leak outside Containment in the Unit 1 Safeguards Building.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 6√
2.3.8 RNO 2) a) 1st bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • Close Orifice Isolation Valves:
	    • 1/1-8149A, LTDN ORIFICE ISOL VLV (45 GPM)

Standard:	PLACED 1/1-8149A Handswitch in CLOSE.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 7√
2.3.8 RNO 2) a) 2nd bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CLOSE Orifice Isolation Valves:
	    • 1/1-8149B, LTDN ORIFICE ISOL VLV (75 GPM)

Standard:	PLACED 1/1-8149B Handswitch in CLOSE.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 8
2.3.8 RNO 2) a) 3rd bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CLOSE Orifice Isolation Valves:
	    • 1/1-8149C, LTDN ORIFICE ISOL VLV (75 GPM)

Standard:	VERIFIED 1/1-8149C GREEN Light LIT and RED Light DARK.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 9√
2.3.8 RNO 2) b) 1st bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CLOSE Letdown Isolation Valves:
	    • 1/1-LCV-460, LTDN ISOL VLV

Standard:	PLACED 1/1-LCV-460 Handswitch in CLOSE.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 10√
2.3.8 RNO 2) b) 2nd bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CLOSE Letdown Isolation Valves:
	    • 1/1-LCV-459, LTDN ISOL VLV

Standard:	PLACED 1/1-LCV-459 Handswitch in CLOSE.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 11 2.3.8 RNO 2) c)	IF Positive Displacement Pump is operating, THEN perform following:
Standard:	DETERMINED the Positive Displacement Pump is NOT operating.
Comment:	**SAT ☐ UNSAT ☐**

<u>Examiner Note:</u>	**Examinee will adjust 1-FK-121 and 1-HC-182, seal injection flow should be maintained between 6 and 13 gpm during this evolution.**
Perform Step: 12√ 2.3.8 RNO 2) d)	PERFORM the following: • ISOLATE Letdown AND normal charging as follows: • REDUCE charging flow in MANUAL to 32 gpm, WHILE maintaining seal injection flow to each RCP at 8 gpm
Standard:	DEPRESSED Lower Pushbutton on 1-FK-121 and ROTATED 1-HC-182 Counter Clockwise to reduce charging flow 26 to 38 gpm.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 13
2.3.8 RNO 2) e) 1st bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CLOSE the charging pump to loop charging valves:
	    • 1/1-8147 RCS LOOP 1 CHRG VLV

Standard:	DETERMINED 1/1-8147 CLOSED; RED Light DARK, GREEN Light LIT.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 14√
2.3.8 RNO 2) e) 2nd bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CLOSE the charging pump to loop charging valves:
	    • 1/1-8146 RCS LOOP 4 CHRG VLV

Standard:	PLACED 1/1-8146 in CLOSE.
Comment:	**SAT ☐ UNSAT ☐**
Examiner Note:	**1-8105 or 1-8106 must be closed. The critical step is accomplished by closing one of the valves.**

Perform Step: 15√
2.3.8 RNO 2) e) 3rd bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CLOSE the charging pump to loop charging valves:
	    • 1/1-8106 CHRG PMP TO RCS ISOL VLV

Standard:	PLACED 1/1-8106 in CLOSE.
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**1-8105 or 1-8106 must be closed. The critical step is accomplished by closing one of the valves.**

Perform Step: 16√
2.3.8 RNO 2) e) 4th bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CLOSE the charging pump to loop charging valves:
	    • 1/1-8105 CHRG PMP TO RCS ISOL VLV

Standard:	PLACED 1/1-8105 in CLOSE.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 17
2.3.8 RNO 2) f) 1st & 2nd bullets
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • CHECK if leak has been isolated:
	    • PRZR level increasing
	    • Any locally observed leakage abating or stopped.

Standard:	DETERMINED leak has been isolated by OBSERVING PRZR level rising.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 18
2.3.8 RNO 2) g) 1st bullet
	PERFORM the following:
	• ISOLATE Letdown AND normal charging as follows:
	  • IF leakage has been stopped, THEN perform the following:
	    • Place Excess Letdown in service per SOP-103A.

Standard:	DETERMINED SOP-103A is required to PLACE Excess Letdown in service.
Examiner Cue:	**If Examinee asks for Attachment 7 to place Alternate Seal Injection in service, inform the examinee that another operator will perform Attachment 7.**
Examiner Note:	**PROVIDE Examinee with SOP-103A (Procedure 2).**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**The following steps are from SOP-103A, Section 5.5.3.**

CAUTION:
- When Excess Letdown flow is aligned to the top of the VCT, the potential exists to bypass the VCT, supplying non-degassed coolant through the Charging Pump Suction Vent Line to the Charging Pump suctions. Therefore, the Charging Pump Suction Vent Line is isolated prior to aligning Excess Letdown flow to the top of the VCT. Additionally, since no constant vent path is available in this line-up, a LCOAR is entered and monitoring of the Charging Pump Suction Vent Line initiated. Excess Letdown flow is normally aligned to the suction of the charging pumps.
- Excess Letdown should be aligned to the RCDT for ~10 minutes at full flow (HC-123 open) to equalize boron concentration in the Excess Letdown piping, to avoid an unplanned boration or dilution.

NOTE:
- IF Normal Letdown is NOT in service, THEN Excess Letdown can NOT be used indefinitely. It should only be used while repairs are made to normal Letdown Flowpath and during Plant heatup.
- While excess letdown is aligned to the suction of the charging pumps and pressurizer level is constant (charging and letdown flows are matched), the VCT may not outflow to the charging pump suction.
- If the RCS is being borated or diluted through the VCT, then excess letdown should be established to the RCDT per Step 5.5.3.D or to the VCT Auxiliary Spray nozzle per Step 5.5.3.I.

Perform Step: 19 5.5.3.A.1)	PERFORM the following: • CONTACT Radiation Protection to verify that personnel are NOT inside the Excess Letdown Heat Exchanger room prior to placing it in service.
Standard:	NOTIFIED Evaluator that they would contact RP.
Examiner Cue:	**RP states no personnel are in the Excess Letdown Heat Exchanger room.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 20 5.5.3.A.2)	PERFORM the following: • IF Excess Letdown will be subsequently aligned to the VCT, THEN NOTIFY PROMPT that monitoring of the charging pump suction vent line will be required per step 5.5.3.I.
Standard:	NOTIFIED US that PROMPT will need contacting.
Examiner Cue:	**US states that PROMPT will be contacted and the Standard Clearance will be hung if the decision is made to align to the VCT. At this time align to the Charging Pump suction.**
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 21 5.5.3.A.3)	PERFORM the following: • IF Excess Letdown will be subsequently aligned to the VCT, THEN PLACE STND CLR 05786.
Standard:	DETERMINED step is N/A based on prior cue.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 22 5.5.3.B	ENSURE that the following CCW valves are OPEN AND SUPPLYING flow to the Excess Letdown Heat Exchanger. (CB-03) • 1-HS-4710, XS LTDN/RCDT HX CCW SPLY ISOL VLV • 1-HS-4711, XS LTDN/RCDT HX CCW RET ISOL VLV • 1-FI-4703, XS LTDN HX CCW RET FLO
Standard:	DETERMINED 1-HS-4710, 1-HS-4711 are open RED Light LIT, GREEN Light DARK and flow is in the GREEN band on 1-FI-4703.
Comment:	**SAT ☐ UNSAT ☐**

NOTE:
- The following step is performed to ensure that boron concentration in the Excess Letdown lines does not cause an inadvertent boration or dilution of the RCS when it is placed in service to the VCT.
- Full flow (1-HC-123 fully open) should be diverted to the RCDT for at least 10 minutes prior to directing it to the VCT. IF full flow is not possible due to temperature limits, THEN the flush should be extended to at least 30 minutes.

Perform Step: 23√ 5.5.3.C	PLACE 1/1-8143, XS LTDN DIVERT VLV in RCDT.
Standard:	PLACED 1/1-8143 in RCDT.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 24√ 5.5.3.D 1st bullet	OPEN the loop isolation valves to the excess letdown heat exchanger. • 1/1-8153, XS LTDN ISOL VLV
Standard:	PLACED 1/1-8153 in OPEN.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 25√ 5.5.3.D 2nd bullet	OPEN the loop isolation valves to the excess letdown heat exchanger. • 1/1-8154, XS LTDN ISOL VLV
Standard:	PLACED 1/1-8154 in OPEN.
Comment:	**SAT ☐ UNSAT ☐**

CAUTION: Operator experience has shown that fully opening 1-HC-123 at NOP/NOT will cause flashing and/or lifting of the relief valve. To avoid flashing at NOP/NOT, 1-HC-123 should be opened only enough to establish Excess Letdown Flow while maintaining Excess Letdown Temperature less than or equal to 175 degrees as read on 1-TI-122. At NOP/NOT, 1-HC-123 may only be able to be throttled to 10-12% to avoid flashing.

NOTE: Establishing flow to the RCDT slowly will give 1/u-LCV-1003, RCDT LVL CTRL ISOL VLV a chance to respond. This will prevent RCDT level from going too high and possibly prevent receiving the RCDT HI Pressure and HI Vent Pressure alarms.

Perform Step: 26√ 5.5.3.E	SLOWLY THROTTLE OPEN 1-HC-123, XS LTDN HX FLO CTRL to prevent thermal shock to the excess letdown heat exchanger, WHILE MONITORING the following: • MONITOR 1-TI-0122, XS LTDN HX OUT TEMP (CB-06) to ENSURE remains < 175° F. • MONITOR computer point L1003A, RCDT LVL to ENSURE remains approximately 40%.
Standard:	ROTATED 1-HC-123 to increase flow. Maintained 1-TI-0122 < 175°F as indicated by 1-ALB-6A XS LTDN HX OUT TEMP HI not annunciating.
Examiner Note:	**If the operator receives the XS LTDN HX OUT TEMP HI annunciator due to having too much XS letdown flow, it is acceptable to immediately begin to lower the XS letdown flow rate and clear the alarm.**
Terminating Cue:	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Unit 1 is in MODE 1**
- **The crew has determined that a 15 gpm Reactor Coolant System (RCS) leak exists.**
- **Actions of ABN-103, Excessive Reactor Coolant Leakage are in progress.**
- **RCS Auto Makeup has been occurring approximately every 13 minutes.**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **Continue with efforts to identify the source of the RCS leak by performing ABN-103, Excessive Reactor Coolant Leakage Step 2.3.8.**

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1 AND 2

ABNORMAL CONDITIONS PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ________ / ______ LATEST PCN/EFFECTIVE DATE ________ / ______

QUALITY RELATED

EXCESSIVE REACTOR COOLANT LEAKAGE

PROCEDURE NO. ABN-103

REVISION NO. 10

EFFECTIVE DATE: 8/11/16 1200

MAJOR REVISION

CHANGES NOT INDICATED

PREPARED BY (Print): Dillon Richey Ext: 6769

TECHNICAL REVIEW BY (Print): Bettina Withers Ext: 5336

APPROVED BY: Joe Ricks for Dee McGaughey Date: 8/8/16
DIRECTOR, OPERATIONS

1.0 APPLICABILITY

This procedure specifies the actions to be taken in the event of excessive reactor coolant leakage and applies to MODES 1, 2 and 3 with RCS pressure greater than 1000 psig.

This procedure is common to both units. The specific unit designator (1 or 2) is represented within these instructions by the symbol "u". The appropriate unit digit may be substituted for this symbol to obtain the unit specific equipment number. (Example u-FK-121 represents 1-FK-121 for Unit 1 and 2-FK-121 for Unit 2.)

NOTE:	The applicable recovery procedures for RCS leakage in various operational MODES are as follows:

• MODES 1, 2, 3 (RCS PRESS > 1000 psig)	ABN-103,	Excessive Reactor Coolant Leakage
• MODE 3 (RCS PRESS <1000 psig) MODES 4, 5 (RCS Loops filled)	ABN-108,	Shutdown Loss of Coolant
• MODE 5 (RCS Loops NOT filled including anytime at reduced inventory)	ABN-104,	Residual Heat Removal System Malfunction
• MODE 6 (Cavity NOT filled)	ABN-104,	Residual Heat Removal System Malfunction
• MODE 6 (Cavity flooded)	ABN-909,	Spent Fuel Pool/Refueling Cavity Leakage

2.0 EXCESSIVE REACTOR COOLANT LEAKAGE

2.1 Symptoms

a. Annunciator Alarms:

- CNTMT SMP 1 FILL RATE INCREASE (2A-1.6)
- CNTMT SMP 1 LVL HI-HI (2A-1.7)
- CNTMT SMP 2 LVL HI-HI (2A-1.8)
- CNTMT SMP 2 FILL RATE INCREASE (2A-2.6)
- RX CAV SMP LVL HI-HI (2A-2.7)
- CNTMT FAN CLR 3 & 4 CNDS FILL RATE HI (2B-3.12)
- CNTMT FAN CLR 1 & 2 CNDS FILL RATE HI (2B-4.12)
- ANY RCP THBR CLR CCW RET TEMP HI (3B-2.11)
- ANY RCP THBR CLR CCW RET FLO LO (3B-3.11)
- ANY RCP THBR CLR CCW RET FLO HI (3B-4.11)
- PRZR LVL LO (5B-3.6)
- RV FLANGE LKOFF TEMP HI (5C-1.1)
- PRZR LVL DEV LO (5C-1.2)
- RV HEAD/PRZR VENT OUT TEMP HI (5C-4.4)
- CHRG FLO HI/LO (6A-3.4)
- CVCS HELB PS-5385A (6A-3.8)
- CVCS HELB PS-5385 (6A-4.8)
- SG 1 LVL DEV (8A-1.12)
- SG 2 LVL DEV (8A-2.12)
- SG 3 LVL DEV (8A-3.12)
- SG 4 LVL DEV (8A-4.12)

2.1 b. Plant Indications:

- Containment humidity high or increasing
- Containment radiation levels high or increasing
- Incore instrument leakage alarm
- Containment temperature high or increasing
- Containment pressure high or increasing
- Containment dew point increasing
- Increased reactor coolant make-up frequency
- VCT level decreasing
- Charging flow increasing
- Pressurizer relief and safety valve temperature high
- Component cooling water surge tank level increasing
- Component cooling water radiation levels high or increasing
- Steam generator blowdown radiation level increasing
- PRT pressure, level or temperature increasing
- Pressurizer level decreasing
- Condenser off gas radiation level increasing
- Mismatch between steam flow and feedwater flow

2.2 Automatic Actions

a. IF pressurizer level decreases to the Low Level Alarm (5B-3.6), THEN letdown will isolate and pressurizer heaters will be blocked.

b. IF VCT level decreases to the Lo-Lo Level Alarm (6A-4.5), THEN charging pump suction will transfer to the RWST.

c. A RCP thermal barrier heat exchanger failure will isolate the CCW from the affected thermal barrier heat exchangers on high temperature or high flow (3B-2.11, 4.11).

2.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE: The symbol [R] has been located throughout this procedure where real or potential radiation hazards are positively identified. This identification technique should not preclude workers from following good radiation work practices throughout this procedure to ensure their occupational exposure is maintained As Low As Reasonably Achievable (ALARA).

☑ 1 VERIFY charging pump - AT LEAST ONE RUNNING: • 1/u-APPD, PDP • 1/u-APCH1, CCP 1 • 1/u-APCH2, CCP 2	PERFORM the following: a. CLOSE Letdown Orifice Isolation Valves: • 1/u-8149A, LTDN ORIFICE ISOL VLV (45 GPM) • 1/u-8149B, LTDN ORIFICE ISOL VLV (75 GPM) • 1/u-8149C, LTDN ORIFICE ISOL VLV (75 GPM) b. START a CCP. IF CCP NOT available, THEN START the PDP.

NOTE: Step 2 is a Continuous Action Step.

☐ 2 VERIFY PRZR level - STABLE OR TRENDING TO NORMAL LEVEL: • u-LI-459A, PRZR LVL CHAN I • u-LI-461, PRZR LVL CHAN III • u-LI-460A, PRZR LVL CHAN II	ADJUST charging flow in MANUAL to maintain pressurizer level at program level. IF PRZR Level < 17%, THEN ENSURE the following valves CLOSED to isolate letdown: • 1/u-8149A, LTDN ORIFICE ISOL VLV • 1/u-8149B, LTDN ORIFICE ISOL VLV • 1/u-8149C, LTDN ORIFICE ISOL VLV • 1/u-LCV-459, LTDN ISOL VLV • 1/u-LCV-460, LTDN ISOL VLV

"Step continued next page"

2.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
2 Continued	IF PRZR level decreases in an uncontrolled manner during subsequent steps, THEN PERFORM the following: a) TRIP Reactor. b) ACTUATE Safety Injection c) GO TO EOP-0.0A/B. IF PRZR level can NOT be maintained AND letdown is in service, THEN PERFORM the following: a) OPEN 1/u-8149A, LTDN ORIFICE ISOL VLV (45 GPM). b) CLOSE 75 gpm Letdown Orifice: • 1/u-8149B, LTDN ORIFICE ISOL VLV (75 GPM) • 1/u-8149C, LTDN ORIFICE ISOL VLV (75 GPM) c) ENSURE u-PK-131, LTDN HX OUT PRESS CTRL is maintaining approximately 310 psig on u-PI-131, LTDN HX OUT PRESS

NOTE: Operation with charging flow exceeding combined Letdown and VCT Makeup flow may result in Charging Pump suction shifting to RWST.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
	d) IF PRZR level continues to fall, THEN START one additional Charging Pump per SOP-103A/B.

2.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
3 CHECK PRZR Status:	
☑ a. PRZR PORVs - CLOSED: • 1/u-PCV-455A, PRZR PORV • 1/u-PCV-456, PRZR PORV	a. PERFORM the following: 1) IF PRZR pressure < 2335 psig, THEN CLOSE PORV(s). 2) IF any PORV can NOT be closed, THEN CLOSE associated Block Valve. • 1/u-8000A, PRZR PORV BLK VLV • 1/u-8000B, PRZR PORV BLK VLV 3) REFER to Technical Specification 3.4.11
☑ b. PRZR Safety Valves - CLOSED: • u-ZL-8010A, PRZR SFTY VLV A • u-ZL-8010B, PRZR SFTY VLV B • u-ZL-8010C, PRZR SFTY VLV C	b. IF Pressurizer pressure is decreasing in an uncontrolled manner, THEN PERFORM the following: 1) TRIP Reactor. 2) ACTUATE Safety Injection 3) GO TO EOP-0.0A/B.
☑ c. PRZR Spray Valves - RESPONDING NORMALLY TO CONTROL PRESSURE: • u-ZL-455B, RC LOOP 1 PRZR SPR VLV • u-ZL-455C, RC LOOP 4 PRZR SPR VLV	c. PERFORM ABN-705 for spray valve malfunction WHILE continuing this procedure, as necessary.

"Step continued next page"

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2.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
3 Continued	
☐ d. Pressurizer Relief Tank level AND temperature - NO SIGNIFICANT INCREASE: • u-TI-468, PRT TEMP • u-LI-470, PRT LVL • u-PI-469, PRT PRESS	d. CHECK PRZR PORV AND Safety Valves for leakage: • u-TI-463, PRZR PORV OUT TEMP • u-TI-464, PRZR SFTY VLV C OUT TEMP • u-TI-465, PRZR SFTY VLV B OUT TEMP • u-TI-466, PRZR SFTY VLV A OUT TEMP IF leakage is indicated, THEN PERFORM the following: 1) PERFORM OPT-303 to determine leak rate. 2) REFER to Technical Specifications 3.4.13 and 3.4.14.
☐ 4 VERIFY AUTO makeup in service: • 1/u-MU, RCS MU MAN ACT - START • 43/u-MU, RCS MU MODE SELECT - AUTO	PLACE Makeup in service per SOP-104A/B.
☐ 5 VERIFY 1/u-LCV-112A, VCT LVL CTRL VLV - ALIGNED TO VCT.	

2.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 6 CHECK Steam Generator status: a. All Steam Generator levels - NORMAL b. VERIFY SG feedwater/steam flow - NO SIGNIFICANT MISMATCH c. MONITOR PC-11 trends on affected Steam Generators for increased radioactivity.	IF any RCS leakage into Steam Generators is indicated, THEN GO TO ABN-106.
☐ 7 VERIFY primary sampling valves CLOSED - u-MLB-1A2- LIGHTS DARK • 1.1 u-HV-4165, PRZR STM SMPL ISOL VLV OPEN • 2.1 u-HV-4166, PRZR LIQ SMPL ISOL OPEN • 3.1 u-HV-4168, HL 1 SMPL ISOL OPEN • 4.1 u-HV-4169, HL 4 SMPL ISOL OPEN	PERFORM the following: 1) REQUEST that Chemistry notify Control Room when sampling completed. 2) VERIFY primary sampling valves CLOSED when sampling is complete.

2.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

[C] 8 CHECK letdown AND normal charging for leakage:

- ☐ a. Area Radiation Monitor in vicinity of letdown AND charging - NORMAL
  - PPAu21, HRAM PIPE PENET N(S). 810 (u-RE-6259B)
- ☐ b. FFLu60, FAILED FUEL (u-RE-406) - DOES NOT INDICATE LOSS OF FLOW.
- ☐ c. VERIFY VCT level - NORMAL.
- ☐ d. VERIFY RCS Makeup Flow AND makeup intervals - NORMAL.
- ☐ e. VERIFY NO reports of leakage observed.
- ☐ f. VERIFY Letdown flow < 140 gpm

PERFORM the following:

1) NOTIFY Radiation Protection of affected areas.

2) ISOLATE Letdown AND normal charging as follows:

a) CLOSE Orifice Isolation Valves:
  - 1/u-8149A, LTDN ORIFICE ISOL VLV (45 GPM)
  - 1/u-8149B, LTDN ORIFICE ISOL VLV (75 GPM)
  - 1/u-8149C, LTDN ORIFICE ISOL VLV (75 GPM)

b) CLOSE Letdown Isolation Valves:
  - 1/u-LCV-460, LTDN ISOL VLV
  - 1/u-LCV-459, LTDN ISOL VLV

c) IF Positive Displacement Pump is operating,
THEN
PERFORM following:
  - START a Centrifugal Charging Pump per SOP-103A/B.
  - STOP the Positive Displacement Pump.

"Step continued next page"

2.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
8 Continued	d) REDUCE charging flow in MANUAL to 32 gpm, WHILE maintaining seal injection flow to each RCP at 8 gpm. e) CLOSE the charging pump to loop charging valves: ● 1/u-8147 RCS LOOP 1 CHRG VLV ● 1/u-8146 RCS LOOP 4 CHRG VLV ● 1/u-8106 CHRG PMP TO RCS ISOL VLV ● 1/u-8105 CHRG PMP TO RCS ISOL VLV f) CHECK if leak has been isolated: ● PRZR level increasing ● Any locally observed leakage abating or stopped. g) IF leakage has been stopped, THEN PERFORM the following: ● PLACE Excess Letdown in service per SOP-103A/B. ● PLACE Alternate Seal Injection in service per Attachment 7. ● GO TO Step 16.

"Step continued next page"

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

SYSTEM OPERATING PROCEDURE MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____________/______ LATEST PCN/EFFECTIVE DATE PCN 20 / 3/27/171200

LEVEL OF USE:
CONTINUOUS USE

QUALITY RELATED

CHEMICAL AND VOLUME CONTROL SYSTEM

PROCEDURE NO. SOP-103A

REVISION NO. 18

EFFECTIVE DATE: 08-01-2013 1200

MAJOR REVISION - CHANGES NOT INDICATED

PREPARED BY (Print): RANDY A. DAVIS Ext: 0625

TECHNICAL REVIEW BY (Print): TOM BAIN Ext: 5479

APPROVED BY: B. St. Louis for M. R. Smith Date: 07/24/2013
DIRECTOR, OPERATIONS

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1.0 APPLICABILITY

This procedure describes the proper operation of the Chemical and Volume Control System (CVCS). This procedure applies to Unit 1 operation only.

2.0 PREREQUISITES

2.1 CVCS Alignment

- Water source is available.
  - ☐ - Refueling Water Storage Tank available for filling the CVCS.

    OR

  - ☐ - Reactor Makeup and Chemical Control System available for blended flow makeup to the VCT.

☐ • Plant Gas System is aligned to provide nitrogen to the CVCS.

☐ • I&C has completed the instrument lineup per INC-2100A.

☐ • SOP-103A-CS-C01, Control Switch Lineup

☐ • SOP-103A-CS-E01, Electrical Lineup

☐ • SOP-103A-CS-V01, Letdown Restoration Lineup

☐ • SOP-103A-CS-V02, VCT Restoration Lineup

☐ • SOP-103A-CS-V03, Charging Restoration Lineup

☐ • SOP-103A-CS-V04, Demin Restoration Lineup

☐ • SOP-103A-CS-V05, CCP 1-01 Restoration Lineup

☐ • SOP-103A-CS-V06, CCP 1-02 Restoration Lineup

☐ • SOP-103A-CS-V07, PDP Restoration Lineup

☐ • SOP-103A-CS-V08, XS Letdown Restoration Lineup

☐ • CCW is aligned and operating to support CVCS operation.

2.2 Establishing Seal Injection at Low Pressure

- ☐ The CVCS is aligned per Section 5.1.1.
- ☐ RMUW is aligned to RCP stand pipes.
- ☐ RCDT is available to accept seal leakoff water.
- ☐ The Seal Water Heat Exchanger has CCW flow.

2.3 Degassing the Reactor Coolant System

- ☐ The Plant is in Mode 3, 4 or 5.
- ☐ Gaseous Waste Processing System is available for degas operation.
- ☐ Plant Gas System is aligned to provide nitrogen to the CVCS.
- ☐ The CVCS is aligned for normal letdown AND charging.
- ☐ The recycle holdup tank is lined up to receive water diverted from the letdown stream via 1/1-LCV-112A, VCT LVL CTRL VLV.
- ☐ NOTIFY Radiation Protection, Radwaste and Chemistry that degassing of the VCT will commence.
- ☐ I&C has reduced the trip setpoint of 1-PB-0115B, CVCS VOLUME CONTROL TANK PRESS BISTABLE LO, to 10 psig.

2.4 Establishing a Hydrogen Overpressure in the VCT

- ☐ A minimum of one RCP is operating.
- ☐ Letdown AND Charging are in service.
- ☐ The oxygen concentration in the Reactor Coolant System is less than 0.10 ppm.
- ☐ The oxygen concentration in the VCT gas space is less than 1% by volume.
- ☐ Plant Gas System is aligned with sufficient volume to provide hydrogen to the CVCS.
- ☐ Recycle Holdup Tank is available to receive letdown from the CVCS.
- ☐ Gaseous Waste Processing System is in operation and available for VCT purge.

2.5 PDP Startup

☐ • The CVCS is aligned for operation per Section 5.1.1.

☐ • The PDP oil cooler has CCW flow.

☐ • Demineralized Water is available to the PDP stuffing box coolant tank.

☐ • CONTACT Prompt Team to determine if PM#349969 is to be performed for vibration check.

2.6 CCP Startup

☐ • The CVCS is aligned for operation per Section 5.1.1.

☐ • The CCP Lube oil coolers have SSW flow.

CAUTION:
- The Centrigugal Charging Pumps' recirculation flowpath is cooled by the Seal Water Heat Exchanger, which is cooled by Non-Safeguards CCW. Running a CCP on miniflow without CCW flow to the Seal Water Heat Exchanger can result in rapid overheating of the Charging Pump(s) and pump damage. (CR-2014-011016, CR-2014-011831)
- IF a Centrifugal Charging Pump is operated without a recirculation flowpath OR without recirculation cooling, to support testing or other plant requirements, THEN charging forward flow should be maintained $\geq$ 60 gpm (at 130°F) for each operating Charging Pump to ensure sufficient pump cooling. (DBD-ME-255)

☐ • VERIFY 1-ALB-3B, 1.16, SEAL WTR HX CCW RET FLO LO alarm is CLEAR.

CAUTION:
- Effluent boron concentration is required to be known for all demineralizers prior to placing them in service. This boron concentration may have been determined by Chemistry during previous demineralizer operations.
- During the Routine Cation Bed Demin Run to Remove Lithium, effluent boron concentration for the Demin is recorded in the procedure section. For ALL OTHER Demin evolutions, the boron concentration must be LOGGED in the Unit log PRIOR to placing the Demin in service.

NOTE: During a Routine Cation Bed Demineralizer Run to Remove Lithium, an effluent sample of the Cation Bed Demin is not required unless specifically requested by Chemistry.

2.7 Placing Demineralizers In Service.

☐ • Normal letdown AND charging are in service.

☐ • The demineralizer to be placed in service has been filled with resin.

☐ • The demineralizer is filled and vented.

☐ • IF flushing OR placing a CVCS Mixed Bed Demineralizer in service,
THEN
NOTIFY Chemistry to determine sample requirements.

☐ • IF Flushing the CVCS Cation Bed Demineralizer to Current RCS Boron Concentration OR flushing for any other reason,
THEN
NOTIFY Chemistry to be prepared to obtain Cation Bed outlet sample, including boron.

☐ • No resin transfers or flush operations are in progress for the demineralizers selected.

2.8 Shutting Down CVCS For Outage Work.

☐ • RCS level is stable at a level either above or below the RCP seal package

• VERIFY that the Number 1 Seal Leakoff Isolation Valve for any RCP NOT on its backseat is CLOSED.

☐ • 1/1-8141A, RCP 1 SEAL 1 LKOFF VLV

☐ • 1/1-8141B, RCP 2 SEAL 1 LKOFF VLV

☐ • 1/1-8141C, RCP 3 SEAL 1 LKOFF VLV

☐ • 1/1-8141D, RCP 4 SEAL 1 LKOFF VLV

☐ • To prevent damage to the Reactor Cooling Pump seal packages while seal injection is secured, ENSURE that Standard Clearance 05450 has been hung.

2.9 Flushing Boration Flow Paths

☐ • VERIFY Unit is MODE 6 OR NO MODE.

☐ • VERIFY a CCP is running

☐ • VERIFY PDP is STOPPED

☐ • VERIFY charging pump suction aligned from the VCT.

• VERIFY charging pump suction high point vent valves are OPEN.

- ☐ • 1-HV-8220, U1 CHRG PMP SUCT HI PNT VNT VLV 8220
- ☐ • 1-HV-8221, U1 CHRG PMP SUCT HI PNT VNT VLV 8221

3.0 PRECAUTIONS

- An explosive mixture of oxygen and hydrogen in the Volume Control Tank and/or PDP suction stabilizer should be avoided at all times. Oxygen content in the tank and stabilizer should not exceed 5% by volume when hydrogen is present.
- During normal operation Volume Control Tank pressure should be maintained high enough to provide a minimum back pressure of 15 psig on the Reactor Coolant Pump Seals. During degas operation, VCT pressure shall be maintained $\geq$10 psig to prevent reverse pressurization of the RCP number 2 seals. Reverse pressurization could result in RCP seal damage.
- After any significant change in letdown and charging flow, the reactor coolant pump seal injection flows should be checked and adjusted if necessary.
- To avoid thermal shock of the reactor coolant piping when operating at elevated temperature, charging flow should first be preheated in the regenerative heat exchanger. Letdown flow should not be stopped without also reducing charging flow to maintain RCP seal injection only when RCS cold leg temperature is > 350°F.
- Pressure downstream of the letdown orifices should be maintained greater than saturation pressure to preclude flashing of the letdown coolant before it enters the letdown heat exchanger.
- When placing a standby demineralizer in service, care should be taken to avoid the insertion of positive reactivity due to absorption of boron in the bed.
- [C] Except as provided for in EVAL-2007-002946-01, RCP seal injection shall be maintained any time RCS level is above the seal package (84 inches above core plate 830'0") for any RCP not on its backseat.
- Demineralizer resins should be maintained wet per RWS-302.
- The CCP alternate miniflow piping must be filled and vented to ensure the relief valves are not damaged by water hammer in the event of an SI actuation.
- Operation of Demineralizers and associated flow paths has the potential to change RCS Boron Concentration which directly affects Reactivity. Prior to performing evolutions affecting Demineralizers and associated flow paths, ensure all potential effects of the evolution (including potential dilution or boration) are considered.
- Effluent boron concentration is required to be known for all demineralizers prior to placing them in service. This boron concentration may have been determined by Chemistry during previous demineralizer operations.
- During the Routine Cation Bed Demin Run to Remove Lithium, effluent boron concentration for the Demin is recorded in the procedure section. For ALL OTHER Demin evolutions, the boron concentration must be LOGGED in the Unit log PRIOR to placing the Demin in service.

3.0 PRECAUTIONS (continued)

- Borating a demin while the Refueling Cavity is full could result in dilution of Refueling Cavity water inventory due to inadequate mixing of the water in the Refueling Cavity with the potential for inadvertent dilution. REF: OE31072
- When placing a Demineralizer in service, minor RCS temperature changes of approximately 0.5°F may be expected. Minor changes in temperature may occur even for a saturated demin which has recently been in service. This is due to the daily change in RCS boron concentration and the minor delta that develops to the demin piping boron.
- Charging pump suction should normally remain aligned to the VCT due to dissolved oxygen concerns when suction comes from the RWST. When entering a plant outage, suctions should NOT be rolled to the RWST prior to crud burst. When time allows, Chemistry should be notified prior to rolling suction to the RWST.
- The Centrigugal Charging Pumps' recirculation flowpath is cooled by the Seal Water Heat Exchanger, which is cooled by Non-Safeguards CCW. Running a CCP on miniflow without CCW flow to the Seal Water Heat Exchanger can result in rapid overheating of the Charging Pump(s) and pump damage. (CR-2014-011016, CR-2014-011831)
- IF a Centrifugal Charging Pump is operated without a recirculation flowpath OR without recirculation cooling, to support testing or other plant requirements, THEN charging forward flow should be maintained $\geq$ 60 gpm (at 130°F) for each operating Charging Pump to ensure sufficient pump cooling. (DBD-ME-255)

4.0 LIMITATIONS AND NOTES

4.1 Limitations

- During normal operation, maintain VCT pressure between 15 psig and 60 psig.
- During degas operation, maintain VCT at a minimum pressure of 10 psig to prevent damage to the RCP number 2 seals.
- [C] Letdown temperature should not exceed 140°F to the demineralizers.
- Two boron injection subsystems shall be OPERABLE in Modes 1, 2, 3 and 4. (TR 13.1.31)
- One ECCS train shall be OPERABLE in Mode 4. (TS 3.5.3)
- At least one boron injection subsystem shall be OPERABLE and capable of being powered from an OPERABLE emergency power source in MODES 5 and 6. (TR 13.1.32)
- CCP Motor Starting Duty

  1. Motor at ambient temperature: 2 consecutive starts.
  2. Motor at operating temperature: 1 consecutive start.

  Minimum time between starts following conditions 1 or 2.

  a. Motor running between starts - 15 minutes.

  b. Motor standing between starts - 45 minutes.

4.1 Limitations (continued)

[C] • The PDP suction stabilizer gas supply and vent valves should be closed and the PDP should be stopped if the charging pump suction is switched from the VCT to the RWST due to VCT low-low level or operator action. This is applicable when VCT pressure is greater than RWST pressure. Higher VCT pressure will disable the PDP stabilizer vent path and may cause gas binding of the CCP's if 1CS-8200, PD CHRG PMP 1-01 SUCT STAB VNT CHK VLV leaks.

[C] • When the PDP is running and 1/1-8204, H2/N2 SPLY VLV indicates open (red light on), 1/1-8210A, H2/N2 SPLY VLV and 1/1-8210B, H2/N2 SPLY VLV may be opened no more than 10 seconds to clear the high level (1/1-8204 green light on). When 1-ALB-6A, 1.8 "PDP SUCT STAB LVL HI-HI" alarms, operator actions will provide steps to start a CCP and stop the PDP.

- Charging flow through the Regenerative Heat Exchanger is limited to 300 gpm. Due to indication (1-FI-121A), flow is limited to 270 gpm.
- The minimum charging flow from the CCP's with 1-FK-121 in AUTO is 55 gpm. Any charging flow less than 55 gpm will require placing 1-FK-121 in MANUAL.
- Seal injection to the RCP No. 1 seals should not exceed 130°F.
- Seal injection to any RCP No. 1 seal should not exceed 13 gpm.

[C] • Seal injection to any RCP No. 1 seal shall not be less than 6 gpm.

- When RCS temp is ≥ 500 degrees, letdown flow is limited to 140 gpm with the 45 gpm orifice and ONE 75 gpm orifice in service.
- Letdown flow is limited to 170 gpm (when RCS temp is < 500 degrees) with 1 Mixed Bed Demineralizer in service. (Reference EVAL-2005-001409-01-00)
- Letdown flow is limited to 195 gpm (when RCS temp is < 500 degrees) when 2 demineralizers are in service. (Reference FDA-2007-001435-01-00)

4.1 Limitations (continued)

[C] • Seal injection to a coupled RCP may be secured if RCS level is above or below the seal package provided that the following actions are implemented to minimize the exposure to risk associated with this configuration:

- Seal injection should be in service any time RCS level is moving through the seal package.
- The #1 seal leak off isolation valves should be closed.
- No pump should be rotated while seal injection is secured; this will prevent cycling water through the shaft alley and seal package.
- The time with seal injection secured should be limited to the time required to perform maintenance on the Chemical and Volume Control System (CVCS) and testing / surveillances that require seal injection to be secured.
- The RCP Oil Lift system should remain secured during the time that seal injection is isolated to prevent movement of the shaft and possibly cycling water through the shaft and seal package.
- The pumps shall be hand rotated with the RCS at Low Pressure and Seal Injection in service to assist in dislodging any debris/deposits, prior to pump operation.
- A flush of the seals at a higher seal injection flow rate may be used to purge any debris or unfiltered water from the seal package and shaft alley, if necessary.

Although additional risk is incurred by securing seal injection to a coupled pump, this added risk to the seals may be mitigated by implementing the above actions. (Reference EVAL-2007-002946-01-0)

• During certain conditions, it may be necessary to start the CCP before an operator can be dispatched to locally start the Aux Lube Oil Pump. The start of a CCP without starting the Aux Lube Oil Pump is classified as an emergency start and the following limitations apply:

- Any emergency start of a CCP should be recorded in the Unit Log.
- WHEN the Aux Lube Oil Pump has been operated within the last 30-day period THEN CCP bearings retain sufficient lubrication for a CCP start without prior start of the Aux Lube Oil Pump.
- ABNs and ERGs have been evaluated to determine which instructions for a CCP start are considered to be an "emergency" start of the CCP. WHEN ABN instructions reference that a CCP start be performed per SOP-103A, THEN the Aux Lube Oil Pump is expected to be started prior to starting the CCP. ABN instructions that initiate start of a CCP WITHOUT reference to SOP-103A can be performed as an emergency start. Any CCP start within the ERGs is considered an emergency start.

• Degraded CVCS Pump performance may be caused by gas intrusion into the CVCS System. Gas intrusion into the CVCS System may cause fluctuations in OR a reduction in CVCS Pump discharge pressure OR flow, OR increased pump vibration (Reference STA-698, "Gas Intrusion Program").

4.2 Notes

- Attachment 1 and 2 can be used to verify valve and control switch lineups with the system in normal operation.
- The symbol [R] has been located throughout this procedure where real or potential radiation hazards are positively identified. This identification technique should not preclude the worker from following good radiation work practices throughout the task to ensure his/her occupational exposure is maintained As Low As Reasonably Achievable (ALARA).
- The symbol [IV] and [CV] have been located throughout this procedure to identify those steps requiring verification. Initial performance and verification (Independent Verification [IV] or Concurrent Verification [CV]) of these steps shall be documented on the Verification Log Sheet (STA-694-1).
- Following boron saturation of a new demineralizer, RCS boron can be expected to drop. A reduction of RCS boron by 10 to 15 ppm is not unusual. This change is the result of boron being removed from the letdown stream during the saturation evolution and blended flow replacing the boron with boron-10.
- When stopping a CCP, lube oil pressure to the pump bearings will be reduced as the shaft-driven lube oil pump coasts down. When lube oil pressure reduces to < 13 psig, the Aux Lube Oil Pump automatically starts and will automatically stop as the lube oil pressure exceeds > 18 psig. The Aux Lube Oil Pump may cycle a few times (normally 3 to 5 times) before remaining on.
- Modifying notes in attachments appear on the bottom of the applicable page and again on the last page of the attachment.
- The interaction of controllers FK-121, LK-459, & SK-459A is complex. When alternating between PDP & CCP operation, LK-459 must be adjusted to accomplish smooth operation. IF a CCP is operating, steady state demand on LK-459 will be ~1/3 the indicated flow of FI-121A. IF the PDP is operating, the demand of LK-459 will be ~matched to the output of SK-459A. These values assume previous steady state, automatic, 100% power operation, but can be used as guidance for manual adjustments.

[C]
- When Excess Letdown flow is aligned to the top of the VCT, the potential exists to bypass the VCT, supplying non-degassed coolant through the Charging Pump Suction Vent Line to the Charging Pump suctions. Therefore, the Charging Pump Suction Vent Line is isolated prior to aligning the Excess Letdown flow to the VCT. Additionally, since no constant vent path is available in this line-up, a LCOAR is entered and ultrasonic monitoring of the Charging Pump Suction Vent Line initiated. Excess Letdown flow is normally aligned to the suction of the charging pumps.

4.2 Notes (continued)

- Proper oil level for the PDP Fluid Drive Unit is as follows (SMF-05-2603):
  - With the PDP stopped, oil level should be in the upper 1/4 of the MIN - MAX range, not to exceed the MAX oil level mark.
  - With the PDP running, oil level should NOT drop below the MIN oil level mark. Overfilling can cause unnecessary heating of the oil, and increased load on the motor

- After each PDP run, the PDP boron placard should be updated to ensure the next PDP run will have current boron concentration information.

5.5.3 Placing Excess Letdown in Service

This section describes the steps to place Excess Letdown in service.

CAUTION:
- When Excess Letdown flow is aligned to the top of the VCT, the potential exists to bypass the VCT, supplying non-degassed coolant through the Charging Pump Suction Vent Line to the Charging Pump suctions. Therefore, the Charging Pump Suction Vent Line is isolated prior to aligning Excess Letdown flow to the top of the VCT. Additionally, since no constant vent path is available in this line-up, a LCOAR is entered and monitoring of the Charging Pump Suction Vent Line initiated. Excess Letdown flow is normally aligned to the suction of the charging pumps.
- Excess Letdown should be aligned to the RCDT for ~10 minutes at full flow (HC-123 open) to equalize boron concentration in the Excess Letdown piping, to avoid an unplanned boration or dilution.

NOTE:
- IF Normal Letdown is NOT in service, THEN Excess Letdown can NOT be used indefinitely. It should only be used while repairs are made to normal Letdown Flowpath and during Plant heatup.
- While excess letdown is aligned to the suction of the charging pumps and pressurizer level is constant (charging and letdown flows are matched), the VCT may not outflow to the charging pump suction.
- If the RCS is being borated or diluted through the VCT, then excess letdown should be established to the RCDT per Step 5.5.3.D or to the VCT Auxiliary Spray nozzle per Step 5.5.3.I.

A. PERFORM the following:

☐ 1) CONTACT Radiation Protection to verify that personnel are NOT inside the Excess Letdown Heat Exchanger room prior to placing it in service.

☐ 2) IF Excess Letdown will be subsequently aligned to the VCT,
THEN
NOTIFY PROMPT that monitoring of the charging pump suction vent line will be required per step 5.5.3.I.

☐ 3) IF Excess Letdown will be subsequently aligned to the VCT,
THEN
PLACE STND CLR 05786.

5.5.3 B. ENSURE that the following CCW valves are OPEN
<u>AND</u>
SUPPLYING flow to the Excess Letdown Heat Exchanger. (CB-03)

- ☐ • 1-HS-4710, XS LTDN/RCDT HX CCW SPLY ISOL VLV
- ☐ • 1-HS-4711, XS LTDN/RCDT HX CCW RET ISOL VLV
- ☐ • 1-FI-4703, XS LTDN HX CCW RET FLO

> <u>NOTE</u>:
> - The following step is performed to ensure that boron concentration in the Excess Letdown lines does not cause an inadvertent boration or dilution of the RCS when it is placed in service to the VCT.
> - Full flow (1-HC-123 fully open) should be diverted to the RCDT for at least 10 minutes prior to directing it to the VCT. <u>IF</u> full flow is not possible due to temperature limits, <u>THEN</u> the flush should be extended to at least 30 minutes.

☐ C. PLACE 1/1-8143, XS LTDN DIVERT VLV in RCDT.

D. OPEN the loop isolation valves to the excess letdown heat exchanger.

- ☐ • 1/1-8153, XS LTDN ISOL VLV
- ☐ • 1/1-8154, XS LTDN ISOL VLV

> <u>CAUTION</u>: Operator experience has shown that fully opening 1-HC-123 at NOP/NOT will cause flashing and/or lifting of the relief valve. To avoid flashing at NOP/NOT, 1-HC-123 should be opened only enough to establish Excess Letdown Flow while maintaining Excess Letdown Temperature less than or equal to 175 degrees as read on 1-TI-122. At NOP/NOT, 1-HC-123 may only be able to be throttled to 10-12% to avoid flashing.

> <u>NOTE</u>: Establishing flow to the RCDT slowly will give 1/u-LCV-1003, RCDT LVL CTRL ISOL VLV a chance to respond. This will prevent RCDT level from going too high and possibly prevent receiving the RCDT HI Pressure and HI Vent Pressure alarms.

E. SLOWLY THROTTLE OPEN 1-HC-123, XS LTDN HX FLO CTRL to prevent thermal shock to the excess letdown heat exchanger,
<u>WHILE</u>
MONITORING the following:

- ☐ • MONITOR 1-TI-0122, XS LTDN HX OUT TEMP (CB-06) to ENSURE remains < 175° F.
- ☐ • MONITOR computer point L1003A, RCDT LVL to ENSURE remains approximately 40%.

5.5.3 F. ENSURE seal injection flow is between 6-10 gpm per RCP.

- ☐ • 1-FI-145, RCP 1 SEAL WTR INJ FLO
- ☐ • 1-FI-144, RCP 2 SEAL WTR INJ FLO
- ☐ • 1-FI-143, RCP 3 SEAL WTR INJ FLO
- ☐ • 1-FI-142, RCP 4 SEAL WTR INJ FLO

> NOTE: Full flow (1-HC-123 fully open) should be diverted to the RCDT for at least 10 minutes prior to directing it to the VCT. IF full flow is not possible due to temperature limits, THEN the flush should be extended to at least 30 minutes.

☐ G. ENSURE flush time COMPLETE

> NOTE: [C]
> - IF the Charging Pump Suction Vent Line is not available for service, THEN Excess Letdown shall be aligned to the top of the VCT.
> - IF Normal Letdown is in service (NOT bypassing the VCT per IPO-005A), THEN Excess Letdown may be left in service to the CCP suction indefinitely. (EVAL-05-1803-01)
> - IF Excess Letdown is to remain in operation for > 4 hours, with Normal Letdown NOT in service, THEN excess letdown/seal water return flow shall be aligned to the top of the VCT (through the VCT auxiliary spray nozzle).

H. IF it is desired to align Excess Letdown flow to the charging pump suction,
THEN
PERFORM the following:

☐ 1) IF Excess Letdown flow is to be aligned for > 4 hours,
THEN
ENSURE Normal Letdown is in service.

☐ 2) VERIFY OPEN 1-HV-8220 and 1-HV-8221.

☐ 3) PLACE 1/1-8143, XS LTDN DIVERT VLV in the VCT position.

> NOTE: The following step requires more frequent monitoring of local parameters until stabilization of the temperatures occurs.

☐ 4) IF required,
THEN
ADJUST CCW to the Seal Water Heat Exchanger by throttling 1CC-0341, SL WTR HX 1-01 CCW RET ISOL VLV.
TO
Maintain outlet temperature between 90°F and 110°F on 1-TI-0177, CVCS SEAL WATER HEAT EXCHANGER 1-01 OUTLET TEMPERATURE INDICATOR, (Letdown heat exchanger valve room).

5.5.3 H.

☐ 5) IF it is necessary to subsequently re-align Excess Letdown flow to the top of the VCT,
THEN
PLACE 1/1-8143, XS LTDN DIVERT VLV in the RCDT position
AND
PROCEED to step 5.5.3.I.

[C]

> NOTE:
> - With Excess Letdown and Seal Leakoff aligned to the top of the VCT, VCT level will continue to rise if LCV-112B & 112C are closed. Normal alignment is to the charging pump suction (1-8484 open, 1-8482 locked closed) and the alternate alignment is to the top of the VCT (1-8484 closed, 1-8482 unlocked and open).
> - When excess letdown is aligned to the top of the VCT, the Charging Pump Suction Vent Line is isolated to ensure dissolved gases in the excess letdown flow are not introduced to the suction of the charging pumps.
> - If charging pump suction is transferred to the RWST while excess letdown is aligned to the top of the VCT, level in the VCT will rise rapidly if either RCP seal return or CCP normal miniflow remain in service or are subsequently placed in service.

I. IF it is necessary to align Excess Letdown flow to the top of the VCT,
THEN
PERFORM the following:

1) IF normal letdown flow is being bypassed around the VCT,
THEN
PERFORM ONE of the following:

☐ • RESTORE letdown flow to the VCT by performing IPO-005A steps to restore the VCT to service,

-OR-

☐ • NOTIFY PROMPT to monitor the Charging Pump Suction Vent Line for gas bubble formation for at least 30 minutes after Excess Letdown is established to the top of the VCT.

☐ 2) IF normal letdown flow is NOT bypassing the VCT,
THEN
NOTIFY PROMPT to check the Charging Pump Suction Vent Line for gas bubble formation within 4 hours after Excess Letdown is established to the top of the VCT.

☐ 3) INITIATE LCOAR ODA-308-13.1.31-2 for placement of Excess Letdown in service to the top of the VCT.

5.5.3 I. 4) CLOSE the charging pump suction high point vent valves.

- ☐ • 1-HV-8220, U1 CHRG PMP SUCT HI PNT VNT VLV 8220
- ☐ • 1-HV-8221, U1 CHRG PMP HI PNT VNT VLV 8221

☐ 5) UNLOCK AND OPEN 1-8482, U1 RC PMP SL WTR RET VCT ISOL VLV (SG 832' VOLUME CONTROL 1-01 VALVE ROOM).

☐ 6) CLOSE 1-8484-RO, U1 RC PMP SL WTR RET TO CHRG PMP SUCT VLV RMT OPER (AB 810' CHARG PMP VALVE ROOM).

☐ 7) PLACE 1/1-8143, XS LTDN DIVERT VLV in the VCT position.

<u>NOTE</u>: The following step requires more frequent monitoring of local parameters until stabilization of the temperatures occurs.

☐ 8) <u>IF</u> required,
<u>THEN</u>
ADJUST CCW to the Seal Water Heat Exchanger by THROTTLING 1CC-0341, SL WTR HX 1-01 CCW RET ISOL VLV,
<u>TO</u>
MAINTAIN 1-TI-0177, CVCS SEAL WATER HEAT EXCHANGER 1-01 OUTLET TEMPERATURE INDICATOR (Ltdn Heat Exchanger 1-01 Vlv Rm) between 90°F and 110°F.

☐ 9) <u>AFTER</u> the initial Charging Pump Suction Vent Line monitoring is complete,
<u>THEN</u>
CONTINUE monitoring the vent line as directed by LCOAR ODA-308-13.1.31-2.

COMMENTS ______________________________

Facility: CPNPP JPM # NRC S-3 Task # RO1507N K/A # 011 EA1.11 4.2 / 4.2 SF-3

Title: Transfer From Hot Leg Recirculation back to Cold Leg Recirculation

Examinee (Print): ________________________________

Testing Method:

Simulated Performance:	______	Classroom:	______
Actual Performance:	X	Simulator:	X
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- A Large Break Loss of Coolant Accident occurred on Unit 1 27 hours ago.

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- TRANSFER Residual Heat Removal Pumps and Safety Injection Pumps from Hot Leg Recirculation back to Cold Leg Recirculation per EOS-1.4A, Transfer to Hot Leg Recirculation, Attachment 2, TRANSFER TO COLD LEG RECIRCULATION FROM HOT LEG RECIRCULATION

Task Standard: UTILIZED EOS-1.4A, Attachment 2, and TRANSFERRED Residual Heat Removal Pumps and Safety Injection Pumps to Cold Leg Recirculation.

Ref. Materials: EOS-1.4A, Transfer to Hot Leg Recirculation, Attachment 2, TRANSFER TO COLD LEG RECIRCULATION FROM HOT LEG RECIRCULATION, Rev. 9

Validation Time: 12 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ________________________________ Date: ______________

SIMULATOR SETUP

SIMULATOR OPERATOR:
INITIALIZE to IC-48

OR

INITIALIZE to IC-18 and PERFORM the following:

- **EXECUTE malfunction RC08C2, Hot Leg Loop 3 Large Break LOCA.**
- **Perform Actions of EOP-0.0A, EOP-1.0A, EOS-1.3A and EOS 1.4 to align ECCS for Hot Leg Recirculation and Containment Spray for Recirculation.**

SIMULATOR OPERATOR NOTE:

- **After each JPM, Ensure that all Keys have been removed from the control boards and returned to the key box.**

EXAMINER:

PROVIDE the examinee with a copy of EOS-1.4A, Transfer to Hot Leg Recirculation, Attachment 2, Transfer to Cold Leg Recirculation from Hot Leg Recirculation (Procedure).

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from EOS-1.4A, Attachment 2**
Attachment 2, Step1.	**ALIGN RHR Flow Path For Cold Leg Recirculation One Train At A Time**
Perform Step: 1 1.a.1)	PERFORM the following to align Train A RHR to Cold Leg Recirculation: • CHECK RHR Train A in Hot Leg Recirculation
Standard:	DETERMINED RHR Train A is in Hot Leg Recirculation by OBSERVING flow on 1-FI-988, RHR TO HL 2 & 3 INJ FLO.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 2√ 1.a.2)	PERFORM the following to align Train A RHR to Cold Leg Recirculation: • CLOSE RHRP 1 XTIE VLV: 1/1-8716A
Standard:	PLACED 1/1-8716A, RHRP 1 XTIE VLV in CLOSE.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 3√ 1.a.3)	PERFORM the following to align Train A RHR to Cold Leg Recirculation: • OPEN RHR TO CL 1 & 2 INJ ISOL VLV: 1/1-8809A
Standard:	INSERTED key T-112, RHR System into 69/1-8809A POWER switch and TURNED to ON position then PLACED 1/1-8809A, RHR TO CL 1 & 2 INJ ISOL VLV in OPEN.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 4 1.a.4)	PERFORM the following to align Train A RHR to Cold Leg Recirculation: • VERIFY RHR to CL 1 & 2 INJ FLO. 1-FI-618
Standard:	OBSERVED 1-FI-618 RHR to CL 1 & 2 INJ FLO
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 5 1.b.1)	PERFORM the following to align Train B RHR to Cold Leg Recirculation: • CHECK RHR Train B in hot leg recirculation
Standard:	DETERMINED RHR Train B is in hot leg recirculation by OBSERVING flow on 1-FI-988, RHR TO HL 2 & 3 INJ FLO
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 6√ 1.b.2)	PERFORM the following to align Train B RHR to Cold Leg Recirculation: • CLOSE RHRP 2 XTIE VLV: 1/1-8716B
Standard:	PLACED 1/1-8716B, RHRP 2 XTIE VLV in CLOSE.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 7√ 1.b.3)	PERFORM the following to align Train B RHR to Cold Leg Recirculation: • OPEN RHR TO CL 3 & 4 INJ ISOL VLV: 1/1-8809B
Standard:	INSERTED key T-112, RHR System into 69/1-8809B POWER switch and TURNED to ON position then PLACED 1/1-8809B, RHR TO CL 3 & 4 INJ ISOL VLV in OPEN.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 8 1.b.4)	PERFORM the following to align Train B RHR to Cold Leg Recirculation: • VERIFY RHR to CL 3 & 4 INJ FLO. 1-FI-619
Standard:	OBSERVED 1-FI-619 RHR to CL 3 & 4 INJ FLO
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 9 1.c.1)	CHECK if RHR to HL 2 & 3 INJ ISOL VLV. 1/1-8840 should be closed • CHECK that NO RHR pump is injecting into hot legs
Standard:	DETERMINED NO RHR pumps were injecting into hot legs by OBSERVING NO flow on 1-FI-988, RHR TO HL 2 & 3 INJ FLO
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 10√ 1.c.2	CHECK if RHR to HL 2 & 3 INJ ISOL VLV. 1/1-8840 should be closed: • CLOSE RHR TO HL 2 & 3 INJ ISOL VLV: 1/1-8840
Standard:	INSERTED key T-112, RHR System into 69/1-8840 POWER switch and TURNED to ON position then PLACED 1/1-8840, RHR TO HL 2 & 3 INJ ISOL VLV in CLOSE.
Comment:	**SAT** ☐ **UNSAT** ☐

Attachment 2, Step 2.	**ALIGN SI Pumps Flow Path For Cold Leg Recirculation:**
Perform Step: 11 2 a	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • CHECK SI Train A aligned in Hot leg Recirculation
Standard:	OBSERVED SIP 1 red FAN and PUMP lights lit with 1-PI-919, SIP 1 DISCH PRESS and 1-FI-918, SIP 1 DISCH FLO, and SI TO HL 2 & 3 INJ ISOL VLV: 1/1 8802A open.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 12 2.b	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • CHECK SIP 1 XTIE VLV: 1/1-8821A VLV OPEN
Standard:	OBSERVED SIP 1 XTIE VLV: 1/1-8821A VLV CLOSED
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 13√ 2.b (RNO)	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • <u>IF</u> SIP 2 XTIE VLV: 1/1-8821B VLV is OPEN AND SI pump 2 is <u>NOT</u> aligned in COLD LEG RECIRCULATION, <u>THEN</u> CLOSE 1/1-8821B
Standard:	OBSERVED SIP 2 XTIE VLV: 1/1-8821B VLV OPEN and PLACED SIP 2 XTIE VLV: 1/1-8821B VLV to CLOSE
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 14√ 2.c	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • STOP SI pump 1.
Standard:	PLACED 1/1-APSI1, SIP 1 handswitch in STOP
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 15√ 2.d	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • CLOSE SI TO HL 2 & 3 INJ ISOL VLV: 1/1-8802A
Standard:	INSERTED key T-112, RHR System into 69/1-8802A POWER switch and TURNED to ON position then PLACED 1/1-8802A, SI TO HL 2 & 3 INJ ISOL VLV in CLOSE.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 16√ 2.e	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • ENSURE SIP 1 XTIE VLV: 1/1-8821A VLV OPEN
Standard:	OBSERVED SIP 1 XTIE VLV: 1/1-8821A VLV CLOSED. PLACED SIP 1 XTIE VLV: 1/1-8821A VLV in OPEN
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 17√ 2f	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • ENSURE SI TO CL 1 & 4 INJ ISOL VLV 1/1 8835 OPEN
Standard:	INSERTED key T-112, RHR System into 1/1 8835 POWER switch and TURNED to ON position then PLACED 1/1 8835, SI TO CL 1 & 4 INJ ISOL VLV in OPEN.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 18√ 2.g	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • START SI Pump 1
Standard:	PLACED 1/1-APSI1, SIP 1 handswitch in START, OBSERVED SIP 1 red FAN and PUMP lights lit with 1-PI-919, SIP 1 DISCH PRESS.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 19 2.h	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • VERIFY SI pump 1 discharge flow
Standard:	OBSERVED flow on 1-FI-918, SIP 1 DISCH FLO.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 20 2.i	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • CHECK SI Train B- Aligned in HOT LEG RECIRCULATION
Standard:	OBSERVED SIP 2 red FAN and PUMP lights lit with 1-PI-923, SIP 2 DISCH PRESS and 1-FI-922, SIP 2 DISCH FLO, and SI to HL 1 & 4 INJ ISOL VLV: 1/1-8802B open
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 21√ 2.j	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • STOP SI pump 2
Standard:	PLACED 1/1-APSI2, SIP 2 handswitch in STOP
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 22√ 2.k	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • CLOSE SI to HL 1 & 4 INJ ISOL VLV: 1/1-8802B
Standard:	INSERTED key T-112, RHR System into 69/1-8802B POWER switch and TURNED to ON position then PLACED 1/1-8802B, SI TO HL 1 & 4 INJ ISOL VLV in CLOSE.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 23√ 2.l	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • ENSURE SIP 2 XTIE VLV: 1/1-8821B VLV OPEN
Standard:	OBSERVED SIP 2 XTIE VLV: 1/1-8821B VLV CLOSED and PLACED 1/1-8821B VLV to OPEN.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 24 2.m)	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • ENSURE SI TO CL 1 & 4 INJ ISOL VLV 1/1 8835 OPEN
Standard:	OBSERVED SI TO CL 1 & 4 INJ ISOL VLV 1/1 8835 OPEN
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 25√ 2.n)	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • START SI Pump 2
Standard:	PLACED 1/1-APSI2, SIP 2 handswitch in START, OBSERVED SIP 2 red FAN and PUMP lights lit with 1-PI-923, SIP 2 DISCH PRESS
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 26 2.o)	ALIGN SI Pumps Flow Path For Cold Leg Recirculation: • VERIFY SI pump 2 discharge flow
Standard:	OBSERVED flow on 1-FI-922, SIP 2 DISCH FLO.
Terminating Cue:	**This JPM is complete.**
Comment:	**SAT** ☐ **UNSAT** ☐

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **A Large Break Loss of Coolant Accident occurred on Unit 1 27 hours ago.**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **TRANSFER Residual Heat Removal Pumps and Safety Injection Pumps from Hot Leg Recirculation back to Cold Leg Recirculation per EOS-1.4A, Transfer to Hot Leg Recirculation, Attachment 2, TRANSFER TO COLD LEG RECIRCULATION FROM HOT LEG RECIRCULATION**

ATTACHMENT 2
PAGE 1 OF 5

TRANSFER TO COLD LEG RECIRCULATION FROM HOT LEG RECIRCULATION

NOTE: The transfer back to Hot Leg Recirculation is normally performed 24 hours after this attachment is complete. The Plant Staff may direct transfer to Hot Leg Recirculation at an interval less than 24 hours based on the possibility of core recriticality due to boron plateout.

1. Align RHR Flow Path For Cold Leg Recirculation One Train At A Time

   a. Perform the following to align Train A RHR to Cold Leg Recirculation:

      1) Check RHR Train A in hot leg recirculation.
         - RNO: 1) Go to Step 1b.

      2) Close RHRP 1 XTIE VLV:
         - 1/1-8716A

      3) Open RHR TO CL 1 & 2 INJ ISOL VLV:
         - 1/1-8809A

      4) Verify RHR TO CL 1 & 2 INJ FLO, 1-FI-618.
         - RNO: 4) Perform the following:
           - A) Close RHR TO CL 1 & 2 INJ ISOL VLV:
             - 1/1-8809A
           - B) Open RHRP 1 XTIE VLV:
             - 1/1-8716A
           - C) Verify RHR TO HL 2 & 3 INJ FLO, 1-FI-988.
           - D) Consult with Plant Staff to evaluate long term core cooling.

-CONT 1-

ATTACHMENT 2
PAGE 2 OF 5

TRANSFER TO COLD LEG RECIRCULATION FROM HOT LEG RECIRCULATION

E) IF RHR Train B available, THEN perform Step 1b and attempt to establish Cold Leg Recirculation via that train.

F) IF Hot Leg Recirculation from RHR can NOT be established, THEN close RHR TO HL 2 & 3 INJ ISOL VLV, 1/1-8840. Go to Step 2.

b. Perform the following to align Train B RHR to Cold Leg Recirculation:

1) Check RHR Train B in hot leg recirculation.

1) Go to Step 1c.

2) Close RHRP 2 XTIE VLV:

- 1/1-8716B

3) Open RHR TO CL 3 & 4 INJ ISOL VLV:

- 1/1-8809B

4) Verify RHR TO CL 3 & 4 INJ FLO, 1-FI-619.

4) Perform the following:

A) Close RHR TO CL 3 & 4 INJ ISOL VLV:

- 1/1-8809B

B) Open RHRP 2 XTIE VLV:

- 1/1-8716B

C) Verify RHR TO HL 2 & 3 INJ FLO, 1-FI-988.

D) Consult with Plant Staff to evaluate long term core cooling.

-CONT 1-

TRANSFER TO COLD LEG RECIRCULATION FROM HOT LEG RECIRCULATION

c. Check if RHR TO HL 2 & 3 INJ ISOL VLV, 1/1-8840 should be closed:

1) Check that NO RHR pump is injecting into hot legs.

1) DO NOT close 1/1-8840. Go to Step 2.

2) Close RHR TO HL 2 & 3 INJ ISOL VLV:

- 1/1-8840

2) IF 1/1-8840 can NOT be closed, THEN consult Plant Staff to evaluate RHR alignment. Go to Step 2.

2. Align SI Pumps Flow Path For Cold Leg Recirculation:

a. Check SI Train A - ALIGNED IN HOT LEG RECIRCULATION

a. Go to Step 2i.

b. Check SIP 1 XTIE VLV - OPEN:

- 1/1-8821A

b. IF SIP 2 XTIE VLV, 1/1-8821B is open AND SI pump 2 NOT aligned in Cold Leg Recirculation, THEN close 1/1-8821B.

c. Stop SI pump 1.

d. Close SI TO HL 2 & 3 INJ ISOL VLV.

- 1/1-8802A

e. Ensure SIP 1 XTIE VLV open:

- 1/1-8821A

f. Ensure SI TO CL 1-4 INJ ISOL VLV open:

- 1/1-8835

g. Start SI pump 1.

-CONT 2-

ATTACHMENT 2
PAGE 4 OF 5

TRANSFER TO COLD LEG RECIRCULATION FROM HOT LEG RECIRCULATION

h. Verify SI pump 1 discharge flow.	h. Perform the following: 1) Stop SI pump 1. 2) Close SIP 1 XIE VLV: • 1/1-8821A 3) Open SI TO HL2 &3 INJ ISOL VLV: • 1/1-8802A 4) Start SI pump 1 to re-establish Hot Leg Recirculation flow. Consult Plant Staff to evaluate long term core cooling.
i. Check SI Train B - ALIGNED IN HOT LEG RECIRCULATION	i. Go to Step 3.
j. Stop SI pump 2.	
k. Close SI TO HL 1 & 4 INJ ISOL VLV: • 1/1-8802B	
l. Ensure SIP 2 XTIE VLV open: • 1/1-8821B	
m. Ensure SI TO CL 1•4 INJ ISOL VLV open: • 1/1-8835	

-CONT 2-

ATTACHMENT 2
PAGE 5 OF 5

TRANSFER TO COLD LEG RECIRCULATION FROM HOT LEG RECIRCULATION

n. Start SI pump 2.

o. Verify SI pump 2 discharge flow.

o. Perform the following:

1) Stop SI pump 2.

2) Close SIP 2 XTIE VLV:

- 1/1-8821B

3) Open SI TO HL 1 & 4 INJ ISOL VLV:

- 1/1-8802B

4) Start SI pump 2 to re-establish Hot Leg Consult Plant Staff to Recirculation flow. evaluate long term core cooling.

3. Notify Plant Staff to evaluate possibility of core recriticality prior to transfer back to Hot Leg Recirculation.

4. Return To Procedure And Step In Effect.

Facility: CPNPP JPM # NRC S-4 Task # RO3516A K/A # 061 A2.07 3.4 / 3.5 SF-4S

Title: Respond to Inadvertent Start of Turbine Driven Auxiliary Feedwater Pump

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	______
Actual Performance:	X	Simulator:	X
Alternate Path:	X	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Unit 1 is at 100% power
- Nuclear Instrument NI-43 has failed high
- ABN-703, Power Range Instrument Malfunction, has been performed and troubleshooting is in progress
- No Switchyard activities are in progress
- No other components are INOPERABLE

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- RESPOND to any alarms

Task Standard: UTILIZED ALM-0082A and ABN-305, PLACED Rod Control in AUTOMATIC, INITIATED a 50 MWe Turbine Runback, and TRIPPED the TDAFW Pump.

Ref. Materials: ALM-0082A, 1-ALB-8B, Window 4.5 – TD AFWP STM SPLY VLV LEAKING HV-2452-1/2, Rev. 8.

ABN-305, Auxiliary Feedwater System Malfunction, Rev. 8.

Validation Time: 9 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ______________

SIMULATOR SETUP

SIMULATOR OPERATOR:

INITIALIZE to IC-47 or any at power Initial Condition and LOAD Scenario File "2017 NRC JPM S4" or PERFORM the following:

- **PLACE 'Pink' operator aids on rod control in MANUAL and NI-43 OOS.**
- **When directed, EXECUTE malfunction FW13B, 1-HS-2452-2, AFWPT STM SPLY VLV - MSL 1 to OPEN (Key 1).**

EXAMINER:

When requested, PROVIDE the applicant with a copy of:

- **ALM-0082A, 1-ALB-8B, Window 4.5 – TD AFWP STM SPLY VLV LEAKING HV-2452-1/2 (Procedure 1)**
- **ABN-305, Auxiliary Feedwater System Malfunction, Section 6.0, Inadvertent Turbine Driven AFW Pump Start (Steam Supply Valve Fails Open) (Procedure 2).**

√ - Check Mark Denotes Critical Step

START TIME:	

Booth Operator:	**When directed, EXECUTE malfunction FW13B, 1-HS-2452-2, Turbine Driven AFW Pump Steam Supply Valve fails OPEN.**
Examiner Note:	**The candidate may immediately place Control Rods in AUTO and perform a 50 MW load reduction in response to the start of the Auxiliary Feedwater Pump. Those steps are addressed at JPM Perform Steps 7 and 8.**
Examiner Note:	**The following steps are from 1-ALB-8B, Window 4.5. The ALM procedure is provided to use when the ALM book is referenced.**
Perform Step: 1 1 & 1st bullet	IF not performing AFWPT startup, THEN ensure 1-HS-2452-1, AFWPT STM SPLY VLV - MSL 4 and 1-HS-2452-2, AFWPT STM SPLY VLV - MSL 1 are closed. IF NOT closed, THEN place affected steam supply valve handswitch in PULL OUT • 1-HS-2452-1, AFWPT STM SPLY VLV - MSL 4
Standard:	DETERMINED 1-HS-2452-1, AFWPT STM SPLY VLV MSL 4 in CLOSE and OBSERVED green CLOSE light LIT.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2 1 & 2nd bullet	IF not performing AFWPT startup, THEN ensure 1-HS-2452-1, AFWPT STM SPLY VLV - MSL 4 and 1-HS-2452-2, AFWPT STM SPLY VLV - MSL 1 are closed. IF NOT closed, THEN place affected steam supply valve handswitch in PULL OUT • 1-HS-2452-2, AFWPT STM SPLY VLV - MSL 1
Standard:	PLACED 1-HS-2452-2, AFWPT STM SPLY VLV MSL 1 in PULL OUT and OBSERVED red OPEN light LIT.
Comment:	**SAT ☐ UNSAT ☐**

CAUTION: The turbine driven auxiliary feed pump turbine supply lines should not remain pressurized during normal plant operation due to Environmental Qualification and High Energy Line Break design constraints.	
Perform Step: 3 2 & 2.A	MONITOR 1-SI-2452A, AFWPT SPD. • IF inadvertent start of the Turbine Driven AFW Pump has occurred, THEN go to ABN-305, "AFW System Malfunction" while continuing with this procedure.
Standard:	DETERMINED 1-SI-2452A, AFWPT SPD is at ~4075 rpm.
Examiner Cue:	**The Unit Supervisor directs you to implement ABN-305, Section 6.0.**
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**The following steps are from ABN-305, Section 6.0. The ABN procedure is provided to use when requested.**
NOTE: If the Turbine Driven AFW Pump Steam Supply Valve(s) (u-HS-2452-2 or u-HS-2452-1) are open due to a BOS actuation, the actions of ABN-601 are applicable for addressing the open steam supply valve(s).	
Perform Step: 4 6.3.1 & 1st bullet	CLOSE affected steam supply valves by placing handswitch in – PULL OUT • 1-HS-2452-2, AFWPT STM SPLY VLV – MSL1
Standard:	PLACED 1-HS-2452-2, AFWPT STM SPLY VLV MSL1 in PULL-OUT and OBSERVED red OPEN light LIT.
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**The following steps represent the Alternate Path of this JPM.**
Perform Step: 5 6.3.1 & 6.3.1 RNO	IF affected steam supply valve is closed, THEN go to Step 5. • Continue with Step 2.
Standard:	DETERMINED 1-HS-2452-2, AFWPT STM SPLY VLV MSL1 is NOT CLOSED and REFERRED to Step 2.
Comment:	**SAT ☐ UNSAT ☐**

CAUTION: A loss of efficiency due to steam supply to the TD AFWP, and flow initiation to the SGs could cause Rx Power to exceed 100% (if at or near 100% RTP).

NOTE: Step 2 is a continuous action step.

Perform Step: 6 6.3.2	VERIFY Reactor Power less than or equal to 100%.	
Standard:	OBSERVED 1-NI-041B/042B/044B, PR POWER CHAN I (II, IV) and DETERMINED Reactor Power greater than 100%.	
Comment:		**SAT ☐ UNSAT ☐**

Examiner Note:	**Bulleted steps may be performed in any order.**	
Perform Step: 7√ 6.3.2 RNO 1st bullet	PERFORM the following: • ENSURE 1/u-RBSS, CONTROL ROD BANK SELECT in AUTO.	
Standard:	PLACED 1/1-RBSS, CONTROL ROD BANK SELECT in AUTO.	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 8√ 6.3.2 RNO 2nd bullet	PERFORM the following • INITIATE a 50 MW Turbine Load reduction.	
Standard:	INITIATED a 50 MW Turbine Load reduction as follows: • DEPRESSED 50 MWe Manual Runback button. • CLICKED on “0/1” button. • CLICKED on “EXECUTE” and VERIFIED Runback in progress.	
Comment:		**SAT ☐ UNSAT ☐**

Examiner Cue:	**If asked, REMIND candidate to review Initial Conditions.**
Perform Step: 9 6.3.3 and all bullets	VERIFY AFW System Safety Function Status • Verify <u>BOTH</u> MD AFW pumps OPERABLE, <u>AND</u> • Verify <u>BOTH</u> MD AFW pumps support functions OPERABLE, <u>AND</u> • Verify <u>BOTH</u> DGs OPERABLE, <u>AND</u> • Verify <u>NO</u> Switchyard Activities in-progress impactive to off-site power or Unit generation
Standard:	VERIFIED AFW System Safety Function Status per Initial Conditions.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 10√ 6.3.4	TRIP the TDAFW Pump • 1-HS-2452-F, AFWPT TRIP
Standard:	DEPRESSED 1-HS-2452-F, AFWPT TRIP pushbutton and observed 1-HS-2452G, AFWPT TRIP & THROTTLE VLV green VLV light LIT.
Terminating Cue:	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Unit 1 is at 100% power**
- **Nuclear Instrument NI-43 has failed high**
- **ABN-703, Power Range Instrument Malfunction, has been performed and troubleshooting is in progress**
- **No Switchyard activities are in progress**
- **No other components are INOPERABLE**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **RESPOND to any alarms**

COMANCHE PEAK STEAM ELECTRIC STATION

UNIT 1

ALARM PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____/____ LATEST PCN/EFFECTIVE DATE 17 / 06/03/15 1200

QUALITY RELATED

ALARM PROCEDURE 1-ALB-8B

PROCEDURE NO. ALM-0082A

REVISION NO. 8

EFFECTIVE DATE: 10/18/07 1200

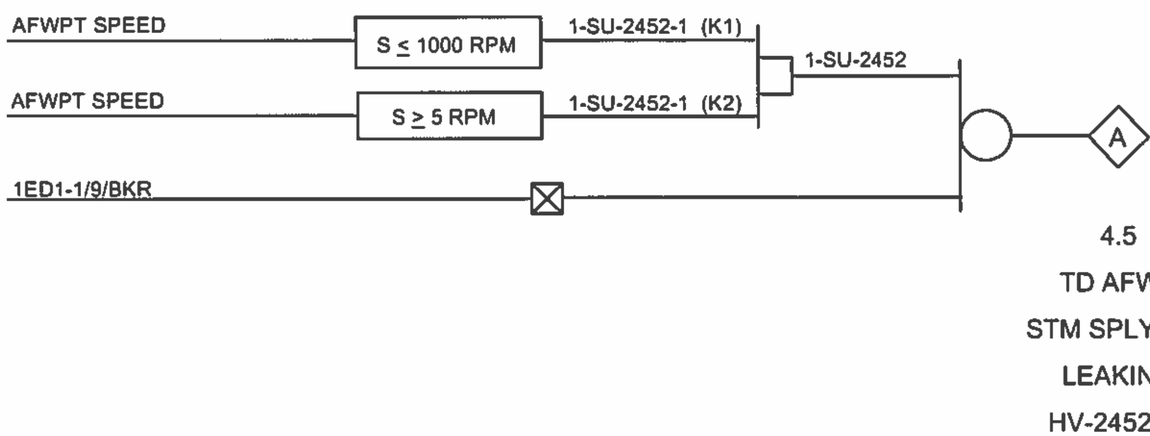
PREPARED BY (Print): J.D. Stone Ext: 0564

TECHNICAL REVIEW BY (Print): Kit Wilson Ext: 5513

APPROVED BY: A. Hall for R.A. Smith Date: 9/15/05
DIRECTOR, OPERATIONS

ANNUNCIATOR NO.: 4.5

LOGIC:



PLANT COMPUTER:

Y6746D	AFWPT MS SPLY VLV MSL 1	Y6411D	AFWPT SPLY VLV MSL 4
Y6046D	AFWPT MS SPLY VLV MSL 1	Y6015D	AFWPT SPLY VLV MSL 4

LOCAL INSTRUMENTS:

NONE

REFERENCES:

CP-0007-003 Terry Steam Turbine

E1-0037 Sh. 32, 35, 42

ANNUNCIATOR NOM./NO.: **TD AFWP STM SPLY VLV LEAKING HV-2452-1/2** **4.5**

PROBABLE CAUSE:

1-HV-2452-1, MSL 1-04 TO AFWPT STM SPLY VLV seat leakage
1-HV-2452-2, MSL 1-01 TO AFWPT STM SPLY VLV seat leakage
1-MS-0711, MSL 1-01 TO AFWPT STM SPLY VLV BYP VLV open
1-MS-0712, MSL 1-04 TO AFWPT STM SPLY VLV BYP VLV open
TDAFWP startup or operation at reduced speed

AUTOMATIC ACTIONS: NONE

NOTE: 1-HS-2452-1, AFWPT STM SPLY VLV - MSL 4 and 1-HS-2452-2, AFWPT STM SPLY VLV - MSL 1 fail open on loss of air or power.

- 1-HS-2452-1 1-TC-26, FB1 Fuse 17 or 19
- 1-HS-2452-2 1-TC-27, FB1 Fuse 17 or 19

OPERATOR ACTIONS:

1. IF not performing AFWPT startup, THEN ensure 1-HS-2452-1, AFWPT STM SPLY VLV - MSL 4 and 1-HS-2452-2, AFWPT STM SPLY VLV - MSL 1 are closed. IF NOT closed, THEN place affected steam supply valve handswitch in PULL OUT
   - 1-HS-2452-1, AFWPT STM SPLY VLV - MSL 4
   - 1-HS-2452-2, AFWPT STM SPLY VLV - MSL 1

CAUTION: The turbine driven auxiliary feed pump turbine supply lines should not remain pressurized during normal plant operation due to Environmental Qualification and High Energy Line Break design constraints.

2. Monitor 1-SI-2452A, AFWPT SPD.
   A. IF inadvertent START of the Turbine Driven AFW Pump has occurred, THEN go to ABN-305, "AFW System Malfunction" while continuing with this procedure

CAUTION:
- The turbine utilizes a shaft driven oil pump to supply bearing and governor assembly lubrication. The pump supplies cooling water to the oil cooler and utilizes pumped fluid for internal lubrication. Operation of pump at flows of <130 gpm for >20 minutes may damage the TDAFWP.
- DO NOT operate the AFWPT at speeds below 1800 rpm for an extended period of time due to loss of oil flow to bearings.

   B. IF speed is >10 rpm and <1800 rpm AND NOT increasing rapidly, THEN perform the following:
      1) Trip turbine driven auxiliary feed pump.
         - 1-HS-2452F, AFWPT TRIP.

CONTINUED......

INTENTIONALLY LEFT BLANK

ANNUNCIATOR NOM./NO.: **TD AFWP STM SPLY VLV LEAKING HV-2452-1/2** **4.5**

OPERATOR ACTIONS: (Continued)

2. B. 2) Verify steam supply isolation bypass valves are closed.

- 1MS-0711, MSL 1-01 TO AFWPT STM SPLY VLV BYP VLV
- 1MS-0712, MSL 1-04 TO AFWPT STM SPLY VLV BYP VLV

3) Monitor downstream pipe temperatures for indication of leakage.

4) Isolate the affected steam supply line.

- 1MS-0101, MSL 1-01 TO AFWPT SPLY VLV UPSTRM ISOL VLV
- 1MS-0128, MSL 1-04 TO AFWPT SPLY VLV UPSTRM ISOL VLV

3. Refer to TS 3.7.5 and 3.6.3.

4. Correct the condition or initiate a work request per STA-606.

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1 AND 2

ABNORMAL CONDITIONS PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____/____ LATEST PCN/EFFECTIVE DATE 2 / 07/22/15 1200 |

QUALITY RELATED

AUXILIARY FEEDWATER SYSTEM MALFUNCTION

PROCEDURE NO. ABN-305

REVISION NO. 8

EFFECTIVE DATE: 6/3/2015 1200

MAJOR REVISION
CHANGES NOT INDICATED

PREPARED BY (Print): LES MELLER EXT: 6009

TECHNICAL REVIEW BY (Print) J.D. STONE EXT: 0564

APPROVED BY: B. ST.LOUIS FOR M.R. Smith DATE: 12/20/2014
DIRECTOR, OPERATIONS

1.0 APPLICABILITY

This procedure describes the actions to be taken in the event of a malfunction of the Auxiliary Feedwater System. This procedure applies to Units 1 and 2 Auxiliary Feedwater Systems.

This procedure is common to both units. The specific unit designator (1 or 2) is represented within these instructions by the symbol "u". The appropriate unit digit may be substituted for this symbol to obtain the unit specific equipment number. (Example uAF-0067 represents 1AF-0067 for Unit 1 and 2AF-0067 for Unit 2.)

> NOTE: The symbol [IV] has been located throughout this procedure to identify steps requiring independent verification. Initial performance and independent verification of these steps shall be documented on the Verification Log Sheet (STA-694-1).

- Section 2.0 - Indicated Main Feedwater Backleakage
- Section 3.0 - Motor Driven Auxiliary Feedwater Pump Malfunction
- Section 4.0 - Turbine Driven Auxiliary Feedwater Pump Malfunction
- Section 5.0 - Inadequate Condensate Storage Tank Level
- Section 6.0 - Inadvertent Turbine Driven AFW Pump Start (Steam Supply Vlv Fails Open)

6.0 INADVERTENT TURBINE DRIVEN AFW PUMP START (STEAM SUPPLY VLV FAILS OPEN)

6.1 Symptoms

a. Annunciator alarms

- TD AFWP STM SPLY VLV ACCUM PRESS LO (8.B - 1.7)
- ANY TD AFWP D/POT LVL HI (momentary alarm) (8.B - 2.6)
- TD AFWP STM SPLY VLV LEAKING HV-2452-1/2 (momentary alarm) (8.B - 4.5)

b. Plant Indications

1) Turbine Driven AFW Pump Steam Supply Valve open indication.

- u-HS-2452-1, AFWPT STM SPLY VLV - MSL 4
- u-HS-2452-2, AFWPT STM SPLY VLV - MSL 1

2) Turbine Driven AFW Pump Speed indication when pump expected to be stopped.

- u-SI-2452A, AFWPT SPD

3) Turbine Driven AFW Pump discharge pressure when pump expected to be stopped.

- u-PI-2455A, TD AFWP DISCH PRESS

4) Turbine Driven AFW Pump discharge flow when pump expected to be stopped.

- u-FI-2458A, TD AFWP DISCH FLO

5) Steam pressure lowering

6) Reactor power rising

6.2 Automatic Action

None

6.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE: If the Turbine Driven AFW Pump Steam Supply Valve(s) (u-HS-2452-2 or u-HS-2452-1) are open due to a BOS actuation, the actions of ABN-601 are applicable for addressing the open steam supply valve(s).

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
1 CLOSE affected steam supply valve by placing handswitch in - PULL OUT	CONTINUE with Step 2.
☐ • u-HS-2452-2, AFWPT STM SPLY VLV - MSL1	
☐ • u-HS-2452-1, AFWPT STM SPLY VLV - MSL4	
☐ IF affected steam supply valve is CLOSED, THEN GO TO Step 5.	

CAUTION: A loss of efficiency due to steam supply to the TD AFWP, and flow initiation to the SGs could cause Rx Power to exceed 100% (if at or near 100% RTP).

NOTE: Step 2 is a continuous action step.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 2 VERIFY Reactor Power less than or equal to 100%.	PERFORM the following: • ENSURE 1/u-RBSS, CONTROL ROD BANK SELECT in AUTO. • INITIATE a 50 MW Turbine Load reduction.

6.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
3 VERIFY AFW System Safety Function Status ☐ • VERIFY BOTH MD AFW Pumps OPERABLE AND ☐ • VERIFY BOTH MD AFW Pumps support functions OPERABLE • Safety Chilled Water • CCW • SSW • AC Distribution • SI/BO Sequencer • AFW Relays AND ☐ • VERIFY BOTH DGs OPERABLE AND ☐ • VERIFY NO Switchyard Activities in-progress impactive to off-site power or Unit generation	DISPATCH operator to locally isolate affected steam supply valve (SG 881' MSL ARV RM): u-HS-2452-2 ☐ • uMS-0101, MSL u-01 TO AFWPT SPLY VLV UPSTRM ISOL VLV u-HS-2452-1 ☐ • uMS-0128, MSL u-04 TO AFWPT SPLY VLV UPSTRM ISOL VLV GO TO Step 6.

6.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
4 TRIP the TDAFW Pump ☐ • u-HS-2452-F, AFWPT TRIP	
5 DISPATCH operator to locally isolate affected steam supply valve (SG 881' MSL ARV RM): u-HS-2452-2 ☐ • uMS-0101, MSL u-01 TO AFWPT SPLY VLV UPSTRM ISOL VLV u-HS-2452-1 ☐ • uMS-0128, MSL u-04 TO AFWPT SPLY VLV UPSTRM ISOL VLV	
☐ 6 VERIFY u-HS-2452H, AFWPT TRIP & THROTTLE VLV, OPER and VLV red lights both lit.	PERFORM the following: ☐ a. Locally RESET the turbine trip and throttle valve per Attachment 1. ☐ b. VERIFY both the OPER and VLV red lights for u-HS-2452H, AFWPT TRIP & THROTTLE VLV lit.
☐ 7 NOTIFY Chemistry that a release has occurred and for Chemistry to determine if a release permit is required per STA-603.	

6.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

8 REFER to Technical Specifications as necessary:

- ☐ TS 3.7.5 for impact to AFW System for current AFW Pump and TD AFW Pump steam supply valve status.
- ☐ TS 3.6.3 for impact to Containment Isolation Valve when u-HV-2452-1 or u-HV-2452-2 is inoperable.
- ☐ TS 3.8.1 if TDAFW Pump or steam supply valve is inoperable WITH an inoperable DG.

☐ 9 ADJUST turbine load as required per IPO-003A/B.

☐ 10 COMPLETE Condition Report per STA-421.

☐ 11 RETURN to procedure and step in effect.

End of Section

Facility: CPNPP JPM # NRC-S5 Task # RO1702 K/A # 103 A2.03 3.5 / 3.8 SF-5

Title: Verify Containment Spray Not Required

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	______
Actual Performance:	X	Simulator:	X
Alternate Path:	X	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Unit 1 has just tripped from 100% power.
- A Loss of Coolant Accident is in progress.

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- VERIFY Containment Spray Not Required per EOP-0.0A, Reactor Trip or Safety Injection, Step 7.

Task Standard: PERFORMED step 7 of EOP-0.0 A, and DETERMINED Containment Spray is required. ESTABLISHED either Train A Containment Spray flow by OPENING the proper valves that failed to automatically open OR Train B Containment Spray flow by STARTING both Train B Containment Spray Pumps that failed to automatically start.

Ref. Materials: EOP-0.0A, Reactor Trip or Safety Injection, Rev. 9.

Validation Time: 8 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ______________________________ Date: ____________

SIMULATOR SETUP

SIMULATOR OPERATOR:

INITIALIZE to IC-51 or any 100% power Initial Condition and PERFORM the following:

- **Insert malfunction for LBLOCA**
- **Insert malfunction to block automatic Containment Spray/Phase B actuation**
- **Insert overrides to prevent 1-HS-4776 & 1-HS-4754 from opening until manually positioned**
- **Insert malfunction to prevent automatic start of Containment Spray Pumps 2&4**
- **Insert overrides to prevent 1-HS-4752 & 1-HS-4753 from opening until manually positioned**
- **FREEZE the Simulator when Containment Spray actuation set point is reached.**

EXAMINER:

PROVIDE the examinee with a copy of:

- **EOP-0.0A, Reactor Trip or Safety Injection, Step 7, Verify Containment Spray Not Required (Procedure 1).**
- **When/If requested EOP-0.0A, Reactor Trip or Safety Injection, Attachment 6, Containment Spray / Phase B Isolation (Procedure 2).**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from EOP-0.0A.**

Perform Step: 1
7 & 7.a
	VERIFY Containment Spray Not Required:
	• Containment pressure - HAS REMAINED LESS THAN 18.0 PSIG
	  • 1-ALB-2B window 1-8, CS ACT - NOT ILLUMINATED
	  -AND-
	  • 1-ALB-2B window 4-11, CNTMT ISOL PHASE B ACT - NOT ILLUMINATED
	  -AND-
	  • Containment pressure – LESS THAN 18 PSIG

Standard:	DETERMINED 1-ALB-2B, Window 1.8 – CS ACT NOT ILLUMINATED and 1-ALB-2B, Window 4.11 – CNTMT ISOL PHASE B ACT NOT ILLUMINATED, and Containment Pressure at 19 psig or greater
Examiner Note:	**Examinee should refer to the RNO once it is determined that containment pressure is > 18 psig**
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 2 7.a RNO a & a.1)	PERFORM the following: • Verify Containment Spray and Phase B Actuation initiated. IF NOT, THEN manually ACTUATE.
Standard:	DETERMINED Containment Spray is NOT actuated with 1-ALB-2B, Window 1.8 – CS ACT - NOT ILLUMINATED
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 3 7.a RNO a & a.1)	PERFORM the following: • VERIFY Containment Spray and Phase B Actuation initiated. IF NOT, THEN manually ACTUATE.
Standard:	DETERMINED Containment Phase B is NOT actuated with 1-ALB-2B, Window 4.11 – CNTMT ISOL PHASE B ACT - NOT ILLUMINATED.
Comment:	**SAT** ☐ **UNSAT** ☐

<u>Examiner Note:</u>	**Examinee will attempt actuation of Phase B from CB-02 <u>and</u> CB-07.**
Perform Step: 4√ 7.a RNO a, a.1), & a.2)	PERFORM the following: • VERIFY Containment Spray and Phase B Actuation initiated. <u>IF NOT</u>, <u>THEN</u> manually ACTUATE. • VERIFY appropriate MLB indication for CNTMT SPRAY (BLUE WINDOWS) <u>AND</u> PHASE B (ORANGE WINDOWS).
Standard:	PERFORMED the following to manually actuate Containment Phase B: • PLACED 1/1-CIPBA1A <u>and</u> 1/1-CIPBA2A, CS/CNTMT ISOL - PHASE B MAN ACT switches at CB-02 to ACT position. • DETERMINED Containment Phase B partially actuated at CB-02.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 5√ 7.a RNO a, a.1), & a.2)	PERFORM the following: • VERIFY Containment Spray and Phase B Actuation initiated. <u>IF NOT</u>, <u>THEN</u> manually ACTUATE. • VERIFY appropriate MLB indication for CNTMT SPRAY (BLUE WINDOWS) <u>AND</u> PHASE B (ORANGE WINDOWS).
Standard:	PERFORMED the following to manually actuate Containment Phase B: • PLACED 1/1-CIPBA1B <u>and</u> 1/1-CIPBA2B, CS/CNTMT ISOL - PHASE B MAN ACT switches at CB-07 to ACT position. • DETERMINED Containment Phase B did NOT actuate any further than using switches on CB-02.
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**The following steps represent the Alternate Path of this JPM.**
Examiner Note:	**Examinee may verify valve position using either the indicating light at the valve or windows on 1-MLB-4A3 or 1-MLB-4B3.** **1-HS-4776, CS HX 1 OUT VLV and 1-HS-4754 CHEM ADD TK DISCH VLV will be closed and must be manually opened to begin spray and chemical addition flow for Train A.**
Examiner Note:	**The following steps are from EOP-0.0A, Attachment 6. Provide the examinee with a copy of Procedure 2 if requested.**
Perform Step: 6 7.a RNO a & a.2) and/or Attachment 6	PERFORM the following: • IF valves NOT aligned, THEN manually ALIGN valve(s) as appropriate. (Refer to Attachment 6 as necessary).
Standard:	DETERMINED 1st two (2) valves positioned as listed: CB-02 1-HS-4754, CHEM ADD TK DISCH VLV CLOSED CB-02 1-HS-4776, CS HX 1 OUT VLV CLOSED The remaining valves are in the correct positions
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**To align Train A Containment Spray both valves 4754 and 4776 must be open. To align Train B Containment Spray both CS pumps 2 and 4 must be started. It is Critical to align at least one Train of Containment Spray.**
Perform Step: 7√ Attachment 6 first 2 items	At CB-02 OPEN 1-HS-4754, CHEM ADD TK DISCH VLV and 1-HS-4776, CS HX 1 OUT VLV
Standard:	PLACED 1-HS-4754, CHEM ADD TK DISCH VLV in open PLACED 1-HS-4776, CS HX 1 OUT VLV OPENED in open
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**Containment Spray pumps 2 and 4 have failed to automatically start. No flow will be indicated on Train B at this time (if 1-HS-4776 was opened in previous step, a small amount of flow maybe observed). Train A is properly aligned and has flow if 2 previous valves were opened in Perform Step 7.**
Perform Step: 8 7.a RNO a & a.3)	PERFORM the following: • VERIFY containment spray flow.
Standard:	OBSERVED proper Containment Spray flow on MCB indicators for Train A OBSERVED little or no Containment Spray flow on MCB flow indicators for Train B
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**Containment Spray pumps 2 and 4 will not be running. This step will be critical if valves 4754 and 4776 have NOT been opened.**
Perform Step: 9√ 7.a RNO a & a.3)	PERFORM the following: • VERIFY containment spray flow. • With no CS flow and an autostart signal present the operators should manually start CSP 2 and 4.
Standard:	STARTED CS Pumps 2 and 4
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 10
7.a RNO a & a.4)
	PERFORM the following:
	• ENSURE CHEM ADD TK DISCH VLVs - OPEN
	  • 1-HS-4752
	  • 1-HS-4753

Standard:	VERIFIED 1-HS-4752 and 4753 open
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 11 7.a RNO a & a.5)	PERFORM the following: • STOP all RCPs.
Standard:	DETERMINED RCPs are running
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 12√ 7.a RNO a & a.5)	STOP Reactor Coolant Pumps. • 1/1-PCPX1, RCP 1	
Standard:	PLACED 1/1-PCPX1, RCP 1 in STOP	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 13√ 7.a RNO a & a.5)	STOP Reactor Coolant Pumps. • 1/1-PCPX2, RCP 2	
Standard:	PLACED 1/1-PCPX2, RCP 2 in STOP	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 14√ 7.a RNO a & a.5)	STOP Reactor Coolant Pumps. • 1/1-PCPX3, RCP 3	
Standard:	PLACED 1/1-PCPX3, RCP 3 in STOP	
Comment:		**SAT ☐ UNSAT ☐**

Perform Step: 15√ 7.a RNO a & a.5)	STOP Reactor Coolant Pumps. • 1/1-PCPX4, RCP 4	
Standard:	PLACED 1/1-PCPX4, RCP 4 in STOP	
<u>Terminating Cue:</u>	**This JPM is complete.**	
Comment:		**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Unit 1 has just tripped from 100% power.**
- **A Loss of Coolant Accident is in progress.**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **VERIFY Containment Spray Not Required per EOP-0.0A, Reactor Trip or Safety Injection, Step 7.**

COMANCHE PEAK NUCLEAR POWER PLANT
UNIT 1
EMERGENCY RESPONSE GUIDELINES

FOR EMPLOYEE USE:
DATE VERIFIED INITIALS ______/______ LATEST PCN/EFFECTIVE DATE PCN-2 / 11/29/16 1200

QUALITY RELATED

REACTOR TRIP OR SAFETY INJECTION

PROCEDURE NO. EOP-0.0A

REVISION NO. 9

EFFECTIVE DATE: 11/03/15 1200

PREPARED BY (Print): TONY SIROIS **EXT:** 6635

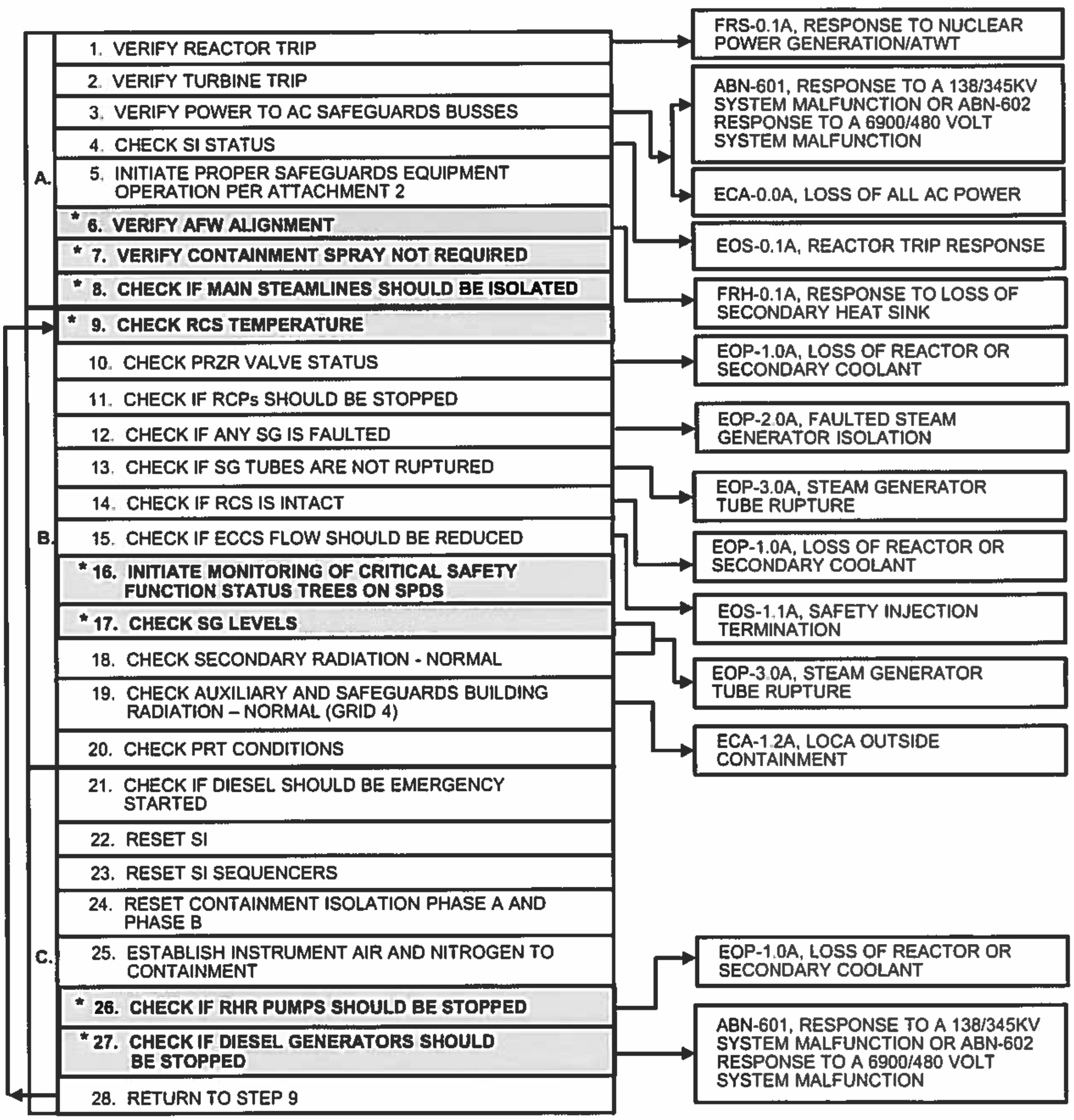
TECHNICAL REVIEW BY (Print): BART SMITH / DAVE WATSON **EXT:** 6220 / 5451

APPROVED BY: JOHN RASMUSSEN FOR DEE McGAUGHEY **DATE:** 09/23/15
DIRECTOR, OPERATIONS

EOP-0.0A **REACTOR TRIP OR SAFETY INJECTION**
REV. 9

MAJOR ACTION CATEGORIES

A. VERIFY AUTO ACTIONS
B. IDENTIFY RECOVERY PROCEDURE
C. SHUTDOWN UNNECESSARY EQUIPMENT AND CONTINUE TRYING TO IDENTIFY APPROPRIATE RECOVERY PROCEDURE



*** CONTINUOUS ACTION STEP**

A. PURPOSE

This procedure provides actions to verify proper response of automatic protection systems following manual or automatic actuation of a reactor trip or safety injection, to assess plant conditions, and to identify the appropriate recovery procedure.

B. APPLICABILITY

This procedure is applicable for initiating events occurring in MODES 1, 2 and 3 GREATER THAN OR EQUAL TO 1000 PSIG. Using this procedure when not in these modes requires a step by step evaluation to determine if the required action is still applicable to current plant conditions.

C. SYMPTOMS OR ENTRY CONDITIONS

1) The following are symptoms that require a reactor trip:

- 2/4 Neutron Flux power ranges greater than 109%
- 2/4 Neutron Flux power ranges greater than 25% (Below P-10 permissive)
- 2/4 Neutron Flux rate trip lights as indicated on NIS cabinets (POSITIVE RATE TRIP)
- 1/2 Neutron Flux source ranges greater than 10^5 CPS (Below P-6 permissive)
- 1/2 Neutron Flux intermediate ranges greater than Amps approximately 25% (Above P-6 permissive and below P-10 permissive)
- 2/4 N-16 power exceed indicated Overtemperature N-16 setpoint
- 2/4 N-16 power greater than 112%
- Pressurizer pressures less than 1880 psig (Above P-7 permissive)
- 2/4 Pressurizer pressures greater than 2385 psig
- 2/3 Pressurizer water levels greater than 92% (Above P-7 permissive)
- 2/3 Reactor coolant loop flows less than 90% on 1/4 loops (Above P-8 permissive)
- 2/3 Reactor coolant loop flows less than 90% on 2/4 loops (Above P-7 and less than P-8 permissives)
- 2/4 Steam Generator levels less than 38% of Narrow Range on 1/4 steam generators
- 2/3 Turbine trip oil pressures less than 60 psig or 4/4 stop valves closed (Above P-9 permissives)
- Any Safety Injection signal
- Any First Out Annunciator lit
- Reactor trip logic met as indicated on the trip status logic bistable (TSLB) lights
- Both SSPS General Warning alarms in (1-ALB-6D, 1-5 and 2-5)

2) The following are symptoms of a reactor trip:

   - Any reactor trip first out annunciator lit.
   - Rapid decrease in neutron flux level.
   - Shutdown and control rods inserted.

3) The following are symptoms that require a safety injection:

   - 2/3 containment pressures greater than 3.0 psig.
   - 2/4 pressurizer pressures less than 1820 psig.
   - 2/3 steam line pressures less than 610 psig in any steam line.

4) The following are symptoms of a safety injection:

   - SI annunciator lit (PCIP or First Out).
   - ECCS pumps running.
   - Diesel Generators running.
   - Non-essential electrical power load shedding.

D. ATTACHMENTS

Attachment 1.A. Foldout For EOP-0.0A Reactor Trip Or Safety Injection

Attachment 1.B. EOP-0.0A Continuous Action Steps

Attachment 1.D. Safeguards Signal Reset Sequence

Attachment 2. Safety Injection Actuation Alignment

Attachment 3. SI Sequencer

Attachment 4. Phase A Isolation

Attachment 5. Containment Ventilation Isolation

Attachment 6. Containment Spray/Phase B Isolation

Attachment 7. Safety Injection Actuation

Attachment 8. Load Shedding

Attachment 9. Post Event System Realignment

Attachment 10. Bases

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
* 7	Verify Containment Spray Not Required:	
	a. Containment pressure - HAS REMAINED LESS THAN 18.0 PSIG • 1-ALB-2B window 1-8, CS ACT - NOT ILLUMINATED -AND- • 1-ALB-2B window 4-11, CNTMT ISOL PHASE B ACT - NOT ILLUMINATED -AND- • Containment Pressure - LESS THAN 18.0 PSIG	a. Perform the following: 1) Verify Containment Spray <u>AND</u> Phase B Actuation initiated. <u>IF NOT</u>, <u>THEN</u> manually actuate. 2) Verify appropriate MLB indication for CNTMT SPRAY (BLUE WINDOWS) <u>AND</u> PHASE B (ORANGE WINDOWS). <u>IF</u> valves <u>NOT</u> aligned, <u>THEN</u> manually align valve(s) as appropriate. (Refer to Attachment 6 as necessary). 3) Verify containment spray flow. 4) Ensure CHEM ADD TK DISCH VLVs - OPEN • 1-HS-4752 • 1-HS-4753 5) Stop all RCPs. 6) Go to Step 8.
	b. Verify containment spray heat exchanger out valves - CLOSED	b. Manually close valve(s).
	c. Verify containment spray pumps - RUNNING	c. Manually start pump(s).

ATTACHMENT 6
PAGE 1 OF 2

CONTAINMENT SPRAY/PHASE B ISOLATION

COMPONENT LOCATION	EQUIPMENT NUMBER	DESCRIPTION	POSITION	ESFAS TRAIN	MLB LOCATION
☐ CB-02	1-HS-4754	CHEM ADD TK DISCH VLV	OPEN	A	1-MLB-4A3/1.9
☐ CB-02	1-HS-4776	CS HX 1 OUT VLV	OPEN	A	1-MLB-4A3/2.7
☐ CB-02	1-HS-4772-1	CSP 1 RECIRC VLV	CLOSED	A	1-MLB-4A3/1.6
☐ CB-02	1-HS-4772-2	CSP 3 RECIRC VLV	CLOSED	A	1-MLB-4A3/2.6
☐ CB-02	1-HS-4755	CHEM ADD TK DISCH VLV	OPEN	B	1-MLB-4B3/1.9
☐ CB-02	1-HS-4777	CS HX 2 OUT VLV	OPEN	B	1-MLB-4B3/2.7
☐ CB-02	1-HS-4773-1	CSP 2 RECIRC VLV	CLOSED	B	1-MLB-4B3/1.6
☐ CB-02	1-HS-4773-2	CSP 4 RECIRC VLV	CLOSED	B	1-MLB-4B3/2.6
☐ CB-03	1-HS-4514	SFGD LOOP CCW SPLY VLV	CLOSED	A	1-MLB-4A3/1.8
☐ CB-03	1-HS-4574	CS HX 1 CCW RET VLV	PARTIALLY OPEN, MLB LIT	A	1-MLB-4A3/3.7
☐ CB-03	1-HS-4572	RHR HX 1 CCW RET VLV	PARTIALLY OPEN, MLB LIT	A	1-MLB-4A3/1.7
☐ CB-03	1-HS-4512	SFGD LOOP CCW RET VLV	CLOSED	A	1-MLB-4A3/2.8
☐ CB-03	1-HS-4527	NON-SFGD LOOP CCW SPLY VLV	CLOSED	B	1-MLB-4B3/3.8
☐ CB-03	1-HS-4525	NON-SFGD LOOP CCW RET VLV	CLOSED	B	1-MLB-4B3/4.8
☐ CB-03	1-HS-4526	NON-SFGD LOOP CCW SPLY VLV	CLOSED	A	1-MLB-4A3/3.8
☐ CB-03	1-HS-4524	NON-SFGD LOOP CCW RET VLV	CLOSED	A	1-MLB-4A3/4.8

ATTACHMENT 6
PAGE 2 OF 2

CONTAINMENT SPRAY/PHASE B ISOLATION

COMPONENT LOCATION	EQUIPMENT NUMBER	DESCRIPTION	POSITION	ESFAS TRAIN	MLB LOCATION
☐ CB-03	1-HS-4515	SFGD LOOP CCW SPLY VLV	CLOSED	B	1-MLB-4B3/1.8
☐ CB-03	1-HS-4575	CS HX 2 CCW RET VLV	PARTIALLY OPEN, MLB LIT	B	1-MLB-4B3/3.7
☐ CB-03	1-HS-4573	RHR HX 2 CCW RET VLV	PARTIALLY OPEN, MLB LIT	B	1-MLB-4B3/1.7
☐ CB-03	1-HS-4513	SFGD LOOP CCW RET VLV	CLOSED	B	1-MLB-4B3/2.8
☐ CB-03	1-HS-4701	RCP CLR CCW RET ISOL VLV	CLOSED	A	1-MLB-4A3/4.9
☐ CB-03	1-HS-4708	RCP CLR CCW RET ISOL VLV	CLOSED	B	1-MLB-4B3/4.9
☐ CB-03	1-HS-4700	RCP/THBR CLR CCW SPLY ISOL VLV	CLOSED	B	1-MLB-4B3/3.9
☐ CB-03	1-HS-4709	THBR CLR CCW RET ISOL VLV	CLOSED	B	1-MLB-4B3/2.9
☐ CB-03	1-HS-4699	RCP/THBR CLR CCW SPLY ISOL VLV	CLOSED	A	1-MLB-4A3/3.9
☐ CB-03	1-HS-4696	THBR CLR CCW RET ISOL VLV	CLOSED	A	1-MLB-4A3/2.9

☐ Notify Unit Supervisor attachment instructions complete AND identify Containment Spray/Phase B Isolation alignment status.

Facility: CPNPP JPM # NRC S-6 Task # RO4302 K/A # 064 A4.06 3.9 / 3.9 SF-6

Title: Load Emergency Diesel Generator

Examinee (Print): ________________________________

Testing Method:

Simulated Performance:	______	Classroom:	______
Actual Performance:	X	Simulator:	X
Alternate Path:	X	Plant:	______
Time Critical:	______		

CUE THE EXAMINEE

Provide the Initial Conditions and Initiating Cue to the Examinee. Any special conditions or instructions should be contained on this sheet.

Initial Conditions: Given the following conditions:

- OPT-214A, Diesel Generator Operability Test is in progress
- Diesel Generator 1-01 has been fast started in accordance with OPT-214A Section 8.1
- All Diesel Generator parameters are normal and stable
- The NEO stationed locally at the Diesel Generator reports no abnormalities in the start or running state of the Diesel Generator

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- Complete section 8.1 of OPT-214A for Diesel Generator 1-01, beginning with Step 8.1.Q

Task Standard: LOADED Diesel Generator 1-01 to a minimum of 2.2 MW. OPENED DG 1-01 output breaker and ADJUSTED DG voltage and frequency for standby conditions when Unit 1 Reactor tripped.

Ref. Materials: OPT-214A, Diesel Generator Operability Test Rev. 22

OPT-214A-1, Train A Diesel Generator Operability Data Sheet, Rev. 19

Validation Time: 15 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ________________________________ Date: ______________

SIMULATOR SETUP

SIMULATOR OPERATOR:

INITIALIZE to IC-53

- **Ensure that NO PCS screens on DAD.**
- **Run 2017 NRC S-6 Scenario File**

OR

INITIALIZE to IC-18 and PERFORM the following:

- **EXECUTE the following conditional malfunctions:**
  - **RC07A, when EDG load is 2.2 MW**
- **Start EDG 1-01 by performing a fast start in accordance with OPT-214A, Section 8.1.**
  - **ANR 20 DG-1 TRBL to NORM**
  - **ANR 25 PC-11 Automatic Annunciator Silence to Silence**

SIMULATOR OPERATOR NOTE:

- **Between each JPM Ensure Synch Switch handle is NOT in SS-1EG1**

EXAMINER:

PROVIDE examinee with the following:

- **OPT-214A, Diesel Generator Operability Test (Procedure)**
- **OPT-214A, Attachment 10.7, TS 3.8.1 Administrative Controls and Test Termination Criteria - Section II (Procedure)**
- **OPT-214A-1, Train A Diesel Generator Operability Data Sheet appropriately marked through 8.1.P (Form)**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from OPT-214A.**
NOTE: SR 3.8.2.1 allows for the DG to be exempted from load testing during MODES 5 AND 6. However, the DG should be loaded to greater than 3.5 MW for at least one hour during each run, regardless of plant MODE.	
Perform Step: 1√ 8.1.Q	TURN SS-1EG1, BKR 1EG1 SYNCHROSCOPE to ON.
Standard:	INSERTED Synchroscope handle in SS-1EG1 and PLACED in ON.
Comment:	**SAT** ☐ **UNSAT** ☐

NOTE: Use of V-IN AND V-RUN to adjust voltage prior to synchronization is the preferred method. This method adjusts DG voltage approximately 50 to 100 volts greater than 1EA1 voltage. The following equipment metering is available as an alternate method.

DG Voltage		SFGD Bus Voltage
V-1EG1, DG 1 VOLT (CB-11) OR V6710A, DG 1 VOLT (Computer Pt.)	TO	V-1EA1-1, BUS 1EA1 VOLT (CB-11) OR V6101A, BUS 1EA1 VOLT (Computer Pt.)

NOTE: DG VOLT should be maintained less than 7150V per Technical Specifications. WITH the AVR TRIP light ON (on at 7185V), the DG is to be considered INOPERABLE until the AVR TRIP light is reset. REFERENCE Attachment 5 of SOP-609A for reset of the AVR TRIP signal.

Perform Step: 2 8.1.R	Using 90-1EG1, DG 1 VOLT CTRL, gradually ADJUST V-IN on the synchroscope 1 to 2 volts higher than V-RUN on the synchroscope.
Standard:	COMPARED V-IN to V-RUN and ADJUSTED as deemed necessary.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 3 8.1.S	Using 65-1EG1, DG 1 SPD CTRL, ADJUST speed so the synchroscope is moving 2 to 4 RPM in the fast direction.
Standard:	ADJUSTED speed such that the synchroscope is moving 2 to 4 RPM in the fast direction.
Comment:	**SAT** ☐ **UNSAT** ☐

NOTE: **"Continuous Action Step"** This step is a compensatory action for the possibility of excessive loading on the DG due to Offsite Power degradation. The termination criteria of Attachment 10.7, Section II apply to the following step.

Perform Step: 4 8.1.T	IF the termination criteria of Attachment 10.7, Section II are met while the DG is synchronized with the offsite power source, THEN PERFORM the following: • OPEN CS-1EG1, DG1 BKR 1EG1 • Slowly ADJUST DG voltage to 6900 V (6831 V to 6969 V) • Slowly ADJUST DG frequency to 60.0 (59.7 to 60.3) Hz.
Standard:	PLACE KEPT Continuous Action Step.
Comment:	**SAT** ☐ **UNSAT** ☐

CAUTION: Following DG Output Breaker closure, load should be raised promptly to prevent Reverse Power Trip. The DG will trip if the Generator is motorized with >34.5 KW IN for greater than 8 seconds.

Perform Step: 5√ 8.1.U 1)	To synchronize the Diesel Generator to the bus, PERFORM the following: • CLOSE CS-1EG1, DG 1 BKR 1EG1 when the synchroscope is slightly before the 12 o'clock position and moving slowly in the fast direction.
Standard:	CLOSED CS-1EG1.
Comment:	**SAT** ☐ **UNSAT** ☐

<u>Examiner Note:</u>	**When DG load reaches 2.2 MW, Unit 1 reactor will trip.**
Perform Step: 6√ 8.1.U 2)	To synchronize the Diesel Generator to the bus, PERFORM the following: • Immediately LOAD the DG to 2.2 – 2.5 MW for stability by moving 65-1EG1, DG 1 SPD CTRL in the RAISE direction.
Standard:	RAISED DG Load to at least 2.2 MW.
Comment:	**SAT** ☐ **UNSAT** ☐

<u>Examiner Note:</u>	**When DG load reaches 2.2 MW, Unit 1 reactor will trip. This step may not be performed.**
Perform Step: 7 8.1.V	TURN SS-1EG1, BKR 1EG1 SYNCHROSCOPE to OFF.
Standard:	PLACED SS-1EG1 to OFF
Comment:	**SAT** ☐ **UNSAT** ☐

<u>Examiner Note:</u>	**When DG load reaches 2.2 MW, Unit 1 reactor will trip. This step may not be performed.**
Perform Step: 8 8.1.W	MAINTAIN 0-500 KVAR out by adjusting 90-1EG1, DG 1 VOLT CTRL while continuing with this procedure
Standard:	ADJUSTED KVARS to maintain reactive load between 0-500 KVAR
Comment:	**SAT** ☐ **UNSAT** ☐

Examiner Note:	**Operator will refer back to step 8.1.T Continuous Action Step**
Examiner Cue:	**Other operators will respond to the reactor trip (if required)**
NOTE: **"Continuous Action Step"** This step is a compensatory action for the possibility of excessive loading on the DG due to Offsite Power degradation. The termination criteria of Attachment 10.7, Section II apply to the following step.	
Perform Step: 9√ 8.1.T	IF the termination criteria of Attachment 10.7, Section II are met while the DG is synchronized with the offsite power source, THEN PERFORM the following: • OPEN CS-1EG1, DG1 BKR 1EG1 • Slowly ADJUST DG voltage to 6900 V (6831 V to 6969 V) • Slowly ADJUST DG frequency to 60.0 (59.7 to 60.3) Hz.
Standard:	• OPENED CS-1EG1, DG1 BKR 1EG1 **(critical)** • Slowly ADJUSTED DG voltage to 6900 V (6831 V to 6969 V) **(not critical)** • Slowly ADJUSTED DG frequency to 60.0 (59.7 to 60.3) Hz. **(not critical)**
Terminating Cue:	**When the operator has opened CS-1EG1, DG1 BKR 1EG1, and adjusted DG voltage and frequency the JPM is COMPLETE**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions:	**Given the following conditions:** • **OPT-214A, Diesel Generator Operability Test is in progress** • **Diesel Generator 1-01 has been fast started in accordance with OPT-214A Section 8.1** • **All Diesel Generator parameters are normal and stable** • **The NEO stationed locally at the Diesel Generator reports no abnormalities in the start or running state of the Diesel Generator**
Initiating Cue:	**The Unit Supervisor directs you to PERFORM the following:** • **Complete section 8.1 of OPT-214A for Diesel Generator 1-01, beginning with Step 8.1.Q**

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

OPERATIONS TESTING MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS Today / JR LATEST PCN/EFFECTIVE DATE PCN -18 / 01/26/17 1200

**LEVEL OF USE:
CONTINUOUS USE**

QUALITY RELATED

DIESEL GENERATOR OPERABILITY TEST

PROCEDURE NO. OPT-214A

REVISION NO. 22

EFFECTIVE DATE: 03/29/12 1200

PREPARED BY (Print): Greg Blythe Ext: 6769

TECHNICAL REVIEW BY (Print): Lisabeth Donley Ext: 6524

APPROVED BY: Alan Hall for Steven Sewell Date: 03/26/12
DIRECTOR, OPERATIONS

1.0 PURPOSE

This procedure satisfies Diesel Generator System testing for the requirements of Technical Specifications Surveillance Requirements as follows:

- Sections 8.1 AND 8.2 verify DG operability by starting, synchronizing AND loading the DG AND ensuring proper fuel oil system status, satisfying TS SR 3.8.1.2, 3.8.1.3, 3.8.1.4, 3.8.1.5 AND 3.8.1.7. These sections also satisfy TS SR 3.8.2.1, 3.8.3.1, 3.8.3.4, TS 5.5.8 AND part of the DG start on Safety Injection test requirements of TS SR 3.8.1.12. PERFORMANCE of breaker AND handswitch alignments, as directed by these sections, satisfy TRS 13.8.31.1.

- Sections 8.3 AND 8.4 VERIFY DG operability by starting the DG, satisfying TS SR 3.8.1.2 as required by Technical Specification action statement 3.8.1.B.

- Sections 8.5 AND 8.6 OPERATE the DG for the continuous 24 Hour Load Run. The Diesel Generator will be loaded for at least 2 hours between 6900KW AND 7700KW (110% rated load) AND immediately followed by at least 22 hours between 6300KW AND 7000KW (100% rated load). These sections will perform all of the requirements of Sections 8.1 AND 8.2, in addition to satisfying TS SR 3.8.1.14, DG 24 Hour Load Run. Sections 8.5 AND 8.6 will NOT PERFORM a Fast Start.

2.0 ACCEPTANCE/REVIEW CRITERIA

2.1 Acceptance Criteria

2.1.1 The acceptance criteria for each section are listed on the Data Sheets.

2.2 Review Criteria

None

3.0 DEFINITIONS/ACRONYMS

3.1 Fast Start- START of the DG with one OR both FAST/SLOW START selector switches in the "FAST" position. Governor air boost is applied. This is a "full fuel" start with the DG reaching rated speed (450 rpm) in approximately 6 seconds. (Normally performed every six months).

3.2 Slow Start- Start of the DG with both FAST/SLOW START selector switches in the "SLOW" position. Upon start, the DG initially accelerates to 200 RPM with air boost automatically isolated. The Governor then ramps the DG to 450 RPM over the next 30 seconds. The DG field is flashed AND governor air boost is restored as the DG passes through 425 RPM. Total time from DG start to rated speed (450 RPM) is approximately 40 seconds.

3.3 Time - Measured from the instant the DG is given a START signal until the lower limits of frequency AND voltage are reached.

3.4 TDI - Transamerica Delaval Inc.

3.5 TDAFWP - Turbine Driven Auxiliary Feedwater Pump

4.0 REFERENCES

4.1 Performance

Technical Specifications

- TS 5.5.8
- TS 3.8.1
- TS 3.8.2
- TS 3.8.3
- TR 13.8.31

CPNPP Procedures

- ABN-912, "Extreme Cold Weather/Heat Tracing and Freeze Protection System Malfunction"
- CHM-150, "Closed Cooling Water Systems" (DELETED CHM-500 series)
- CHM-160, "Diesel Fuel Oil Testing Program"
- COP-609A, "Diesel Generator"
- INC-3024A, "ESF Data Acquisition System Monitoring Setup Train A"
- INC-3025A, "ESF Data Acquisition System Monitoring Setup Train B"
- MSM-P0-3374, "Emergency Diesel Generator Run Related Inspections"
- ODA-308, "LCO Tracking Log"
- OWI-104, "Operations Department Logkeeping and Equipment Inspections"
- OWI-912, "Cold Weather"
- RWS-108, "Vents and Drains System"
- SOP-501A, "Station Service Water System"
- SOP-609A, "Diesel Generator System"

4.1 CPNPP Procedures (continued)

- SOP-610A, "Diesel Generator Fuel Oil and Transfer System"
- SOP-809A, "Diesel Generator Rooms Ventilation System"
- SOP-904, "Main Water Supply Loop and Fire Pumps"
- STA-652, "Radioactive Material Control"
- STA-702, "Surveillance Test Program"
- TSP-503, "Emergency Diesel Generator Reliability Program"

4.2 Development

Applicable Drawings

- M1-0215 series - "Flow Diagrams, Diesel Generator Subsystems"
- M1-2730 Sheets 01 and 02 - "Diesel Generator Pneumatic Diagram"
- E1-0022-1, "Diesel Engine and Diesel Generator Breaker Trip Protection Diagram"
- Delaval 00-500-76001-G, "Control Panel Installation"
- Delaval 09-500-76001 Sheets 3 through 7, Control Panel Schematic
- E1-0067 Sheets 1 through 40 - "Diesel Generator Auxiliary Schematics Sheets 95 through 105 Diesel Generator Control Schematics"
- E1-0184 - "Engine Control Panel 1-DG-01A Interconnection Diagram"
- E1-0185 - "Diesel Generator Local Panel 1-DG-01B Interconnection Diagram"
- E1-0187 - "Engine Control Panel 1-DG-02A Interconnection Diagram"
- E1-0188 - "Diesel Generator Local Panel 1-DG-02B Interconnection Diagram"
- E1-0031 Sheets 21 through 24 - "Diesel Generator Output Breaker Schematics"
- E1-0030 Sheets 51 through 54 - "Remote Manual Control Schematics"

4.2 Development (continued)

FSAR

- Section 8.3, Onsite Power Systems
- Section 9.5, Other Auxiliary Systems

Other References

- TIM-871856
- TIM-871895
- Delaval Instruction Manual, Volume I and Volume III (CP-0034-001)
- NSAC/INPO Significant Event Report (SER) 36-81
- TE-93-2184, "Diesel Vent Fan Operability Matrix"
- TE-95-0450, "Heat Sensitive Diode Tape"
- TE 97-0001, "DG FOST Volume verses Height in inches"
- VL-8906 "Minimum Jacket Water and Lube Oil Temperatures for Starting Engines 76001/04"
- DM 98-054
- PSA Evaluation Log #95
- SOER 03-1, Emergency Power System Operating and Maintenance Practices [Commitment 3688459]

4.3 Commitments

- 00767, DIESEL GENERATOR BUILDING VENTILATION SYSTEM OPERATION
- 01437, DG STARTING SYSTEM TESTING & INSPECTION REQUIREMENTS (FSAR)
- 01438, DG STARTING AIR SYSTEM (FSAR)
- 01622, DG OPERABILITY AT MINIMUM 50% LOAD (FSAR)
- 01638, DG STARTING SYSTEM (FSAR)
- 04920, DG PERIODIC TESTING PROGRAM (FSAR)
- 06224, DG PERIODIC FULL LOAD TEST (FSAR)
- 06572, DG FUEL OIL MAINT. INSP. (FSAR)
- 06793, DG FUEL OIL DAY TANKS & INTEGRAL TANKS
- 07436, DG FUEL OIL STORAGE (ANSI)
- 08222, DG RELIABILITY DEMONSTRATION, PERIODIC TESTING INTERVAL (FSAR)
- 08961, DG FUEL OIL SYSTEM TESTS
- 16317, DG CRANKSHAFT EVALUATION OF SEVERE IMBALANCED CONDITION (SSER-22)
- 23210, EDGs Shall Be Prelubed Prior to Test Starts
- 26880, EDG PREVENTIVE MAINTENANCE PLAN
- 4300287, IER L2 11-46 Rec 2, Extended Emergency Power Operations Following a Loss of Off-Site Power
- 4300306, IER L2 11-46 Rec 7, Extended Emergency Power Operations Following a Loss of Off-Site Power
- 4300297, IER L2 11-46 Rec 4, Extended Emergency Power Operations Following a Loss of Off-Site Power
- 4847904, Test Each Starting Air System Independently

5.0 PRECAUTIONS, LIMITATIONS, NOTES

5.1 Precautions

5.1.1 Engine Roll Water Check

- The indicator cocks on the DG cylinders must be turned counterclockwise to OPEN AND clockwise to CLOSE. When closing, the stem will rise. The indicator cock should seat properly with single hand torque. However, they typically carbon up over time AND,
  IF it becomes difficult to operate OR seat the indicator cock,
  THEN
  a Work Request should be written to clean OR replace the indicator cock.

- Personnel should remain clear of the area immediately in front of the indicator cocks (petcocks) during the engine roll.
  IF lube oil OR fuel has leaked into an engine cylinder(s),
  THEN
  combustion may occur AND flames may exit out of the indicator cocks. (EVAL-2000-3289-01-00)

- A new screwdriver handle indicator cock tool AND a T-handle wrench are available in all four DG Rooms. The T-handle wrench should only be used to position the indicator cock away from the main seat OR the backseat if necessary. The screwdriver handle tool design is to limit excessive force. ENSURE only the screwdriver handle tool is used to CLOSE the indicator cock. See CR-2008-001984.

5.1.2 Diesel Generator Operation

- [C] DO NOT SYNCHRONIZE a DG with off-site power during periods of grid instability OR during severe thunderstorms.

- In response to any emergency start (automatic OR manual emergency) all shutdown protections, except overspeed AND generator differential fault, are deactivated.

- DO NOT OPERATE the DG under steady state conditions at speeds less than 440 rpm in order to avoid resonance frequencies. 440 RPM corresponds to 58.6 HZ. Operation at this low speed would also be below the TS band for frequency of 58.8 to 61.2 HZ.

- [C] MINIMIZE unloaded operation of the DG ($\leq$ 5 minutes recommended).

5.1.2 Diesel Generator Operation (continued)

[C]
- The "No Load" operating duration of the diesel should be minimized as much as possible. After extended "No Load" operation (more than 30 minutes) of the DG, it should be loaded to at least 3.5 MW for 60 minutes to remove any unburned fuel oil in the exhaust system. The Shift Manager shall determine when this is necessary based on the number of starts AND the length of time the DG has been operated in the "No Load" condition.

- DO NOT EXCEED 7.0 MW load on the DG, except as allowed for the 24 Hour Load Run.

- DO NOT EXCEED 5000 KVAR on the DG.

- The band between 6.3 AND 7.0 MW is meant as guidance to avoid routine overloading of the DG. Momentary load excursions outside this band due to changing bus loads shall NOT invalidate this test. Data is taken following the 1 hour run at full load. The time at full load should be as close to 6.4 MW as possible to ensure consistent, useful data is recorded.

- Special test procedures may specify different limitations than those listed above. Special test exceptions will apply when performing the test; the above limits apply at all other times when running the DG.

[C]
- The DG MASTER SWITCH (RLMS) has REMOTE-LOCAL-MAINT positions AND is normally in the REMOTE position. The switch may be placed in the LOCAL position for local manual starting in the event of Control Room evacuation, non-routine testing AND RESET of Shutdown Protection only.

[C]
- IF the DG operates in an unbalanced condition (as evidenced by vibrations OR excessive differences between cylinder exhaust temperatures),
  THEN
  SHUTDOWN the diesel AND NOTIFY the System Engineer.

  - IF any unbalanced condition is identified as severe,
    THEN
    it will be identified to the NRC for review prior to returning the engine to service.

- Cylinder exhaust temperatures should be recorded with the engine operating at a steady state load with exhaust temperatures stabilized. Cylinder exhaust temperature differences can be greater at lower loads (approximately 50%) than at higher loads due to fuel injection pump design AND calibration.

5.1.2 Diesel Generator Operation (continued)

- NOTIFICATION of the groups responsible for monthly run-related activities is required to ensure that licensing commitments are NOT violated.

- DG operating logs must be taken to record AND trend data.

- In the event of a DG trip (manual OR automatic) due to an abnormality, operators should AVOID area of the crankcase reliefs, located on the crankcase doors at the pedestal on the opposite side from the control panel, for approx 30 minutes. Crankcase reliefs have the potential to OPEN shortly after a trip if abnormal conditions cause a pressure rise within the crankcase.

- DG indicator cocks are designed to be operated under full load. In the event an indicator cock is identified as NOT fully closed with the DG running, the NEO should assess the situation to determine if an attempt to CLOSE the indicator cock can be performed safely. The NEO should NOTIFY the Control Room, THEN attempt to CLOSE the DG indicator cock when it is determined safe to do so; otherwise, the NEO should CONTACT the Control Room to STOP the engine in order to CLOSE the indicator cock.
(Ref: EVAL-2009-1652)

5.1.3 Operability

- DO NOT REMOVE a DG from service if the plant is in MODE 1-4 AND any of the following apply:

  - The DG to be checked is the only OPERABLE DG.

  - The plant is currently operating under an ACTION Statement for an INOPERABLE off-site source.

  - Any ESF equipment on the opposite train that relies on the OPERABLE DG as a source of emergency power is INOPERABLE.

  - The Turbine Driven Auxiliary Feedwater Pump is INOPERABLE AND the plant is in MODE 1-3.

- IF the acceptance criteria are NOT satisfied,
THEN
the Shift Manager shall be promptly notified AND the applicable ACTION of TS 3.8.1 OR 3.8.2 implemented, as applicable.

5.1.3 Operability (continued)

- IF both DG FAST/SLOW START SWITCH switches are in SLOW,
  THEN
  the DG is INOPERABLE because it will NOT reach rated speed AND voltage in 10 seconds.

  - IF a Blackout OR SI signal occurs however,
    THEN
    it will respond to the signal AND therefore is still considered "available" for Maintenance Rule Availability criteria.

- Following SHUTDOWN of the diesel generator there is a delay of approximately 2 minutes before the diesel generator will accept a Normal start. This time delay is associated with the diesel generator pneumatic logic board AND may be overridden with an Emergency Start.

- WHEN starting an OPERABLE DG to satisfy TS ACTION statement 3.8.1.B, due to an INOPERABLE DG,
  THEN
  the DG shall NOT be placed in the MAINTENANCE mode to perform a check for water in the cylinders as this will render the DG INOPERABLE.

  - WHEN starting an OPERABLE DG to satisfy TS ACTION statement 3.8.1.B, due to an INOPERABLE DG,
    THEN
    the DG shall NOT be Slow started as this will render the DG INOPERABLE.

- Removing a DG electrical start channel from service (Channel 1- opening CB1 OR CB2; Channel 2 - opening CB3 OR CB4) renders the DG INOPERABLE. REFERENCE ODA-308 Actions to address DG OPERABILITY with a start channel out-of-service.

- During operation of the DG from the Local Generator Control Panel, an automatic signal will NOT automatically start the DG. Placing the MASTER SWITCH (RLMS) in LOCAL renders the DG INOPERABLE.

- While in MAINTENANCE mode, the DG will NOT START. Placing the DG in MAINTENANCE mode to support pre-run checks renders the DG INOPERABLE.

5.1.3 Operability (continued)

- WHEN the DG output breaker transfer control switch (43/1EG1 located at the STP OR 43/1EG2 located at the HSP) is selected to the HSP position,
  THEN
  the diesel will NOT automatically start AND will NOT start from a Control Room manual start.

  - To enable remote starts, RETURN the switch to the CR position. To enable local starts, TURN the MASTER SWITCH (RLMS) to the LOCAL position at the Local Generator Control Panel.

- DG Jacket Water leakage ≤ 1.5 gallons per hour AND the LOW LEVEL JACKET WATER alarm clear assures 7 days of continuous DG operation without the need for makeup to the DG Jacket Water System. The DG remains operable with total Jacket Water leakage ≤ 1.5 gallons per hour AND confidence the leak rate will NOT increase to > 1.5 gallons per hour during DG operation. DG Jacket Water leakage should be evaluated per the Corrective Action Program for continued DG operability based on the size of the leak(s), location of the leak, condition of the leak during DG operation, etc.

  - IF the leak cannot be directly measured from the source,
    THEN
    the relationship of 97.5 gallons per psi (as indicated on 1-LI-3415-1 OR 1-LI-3416) can be used to more accurately estimate the leakrate.

  - Leakage flowrate may be determined by using a graduated collector and a stop watch or for small leaks - 17 drops is equal to a milliliter (ml).

1 gallon = 3785 milliliters

$$\text{GPM} = \frac{\text{collective volume (ml)}}{\text{elapsed time}} \times 0.01585 \frac{\text{gal - sec}}{\text{ml - min}}$$

- In MODES 1 – 4, synchronizing a DG to the bus while the bus is connected to Offsite Power renders the DG inoperable unless the administrative controls of Attachment 10.7 are used (T.S. 3.8.1). In MODES 5 AND 6, the condition is NOT a concern due to the inapplicability of single-failure criteria. (T.S. Bases 3.8.2).

- The following shows the minimum number of DG room exhaust fans required to be available for DG operability based on outside ambient temperature:

Number of Fans Available	Maximum Outside Ambient Temperature for EDG OPERABILITY
1	76.7° F
2	99.4° F
3	106.9° F

Above 106.9°F outside ambient, all 4 fans are required.

5.1.3 Operability (continued)

- IF both DG FAST/SLOW START SWITCH switches are in SLOW AND a start signal is being processed,
  THEN
  REPOSITIONING of the switches will have no effect on the rate of speed increase of the machine.

- The DG space heaters DO NOT affect operability in the standby mode. They are non-safety related equipment AND the only requirement is for them to be off while the DG is operating in emergency.

- Operational experience has shown that on occasion, cam covers may be found with missing OR broken bolts. Engineering Evaluation TE-95-0213 provides analysis which concludes that the joint is acceptable with as few as 5 bolts in the top row AND 5 bolts in the bottom row. (REFERENCE CR-2010-009234 AND TE 95-0213)

- WHEN jacket water or lube oil temperature is less than 120°F,
  THEN
  EDG is rendered INOPERABLE, but is still considered available down to 40°F.

5.2 Limitations

- The following table lists the recommended limits:

Parameter	Recommended Maximum 6.3 to 7.0 MW (Normal Full Load)	Recommended Maximum (110% Load Test)
Turbo Inlet Temperature	1200°F	1250°F during 2 hour 110% load test.
Cylinder Exhaust Temperature Difference	150°F. IF temperature difference exceeds limit, THEN continue to load to full load (6.3-7.0 MW). If difference still greater than limit, THEN NOTIFY the System Engineer.	300°F for eight hours during engine balancing OR cold compression checks OR Diesel partially loaded (IF 300°F exceeded, THEN Engineering should be contacted to evaluate condition.)
Cylinder Exhaust Temperature	>1060°F verify Turbocharger <1200°F OR Reduce DG load to maintain Turbocharger <1200°F	>1100°F verify Turbocharger <1250°F

- As a minimum, the following A.C. electrical power sources shall be OPERABLE in MODES 1-4 per TS 3.8.1:

  - Two physically independent qualified circuits between the offsite transmission network AND the onsite class 1E AC Electrical Power Distribution System;

  - Two separate AND independent diesel generators, capable of supplying the onsite class 1E power distribution subsystem(s), each with a separate fuel oil day tank with a minimum volume of 1440 gallons of fuel

    AND

  - Automatic load sequencers for Train A AND train B.

5.2 Limitations (continued)

- As a minimum, the following A.C. electrical power sources shall be OPERABLE in MODES 5 AND 6 per TS 3.8.2:
  - One circuit between the offsite transmission network AND the onsite class 1E Distribution subsystem required by LCO 3.8.10.
  - One diesel generator capable of supplying one train of the onsite Class 1E AC electrical power distribution subsystem required by LCO 3.8.10 with a fuel oil day tank containing a minimum volume of 1440 gallons of fuel.
- The Stored Diesel Fuel Oil, Lube Oil AND Starting Air Subsystem shall be within limits for each DG required to be OPERABLE per TS 3.8.3 as follows:
  - The Fuel Oil Storage Tank shall contain ≥86,000 gallons (MODES 1-6) of fuel.
  - Lubricating oil inventory shall be ≥ a level 1.75 inches below the low static level on the lube oil dipstick.
  - Required DG starting air receiver pressure shall be ≥180 PSIG. (actual pressure) [Only one air receiver (air compressor) is necessary to maintain the DG OPERABLE, per TE 98-641. The surveillance requires ≥ 184 PSIG due to instrument error AND drift per CALC # IC-CA-0215-5112.]

5.3 Notes

- IF a DG received a manual emergency start from the Control Room,
  THEN
  full shutdown protection may be restored by placing the MASTER SWITCH (RLMS) to LOCAL, the Remote Emergency STOP/START handswitch momentarily to STOP
  AND
  THEN RETURNING the MASTER SWITCH (RLMS) to REMOTE.

- IF a DG received a local emergency start signal,
  THEN
  full shutdown protection can be restored by returning the Local Emergency STOP/START switch to the CENTER position.

  - Full shutdown protection is restored when the SHUTDOWN SYS ACTIVATED light is ON.

- A DG will NOT accept an emergency start signal unless the pressure in at least one start air receiver is greater than 150 psig.

  - The DG will accept the start signal at approximately 150 psig, however, approximately 170 psig is required in the receiver to actually start the DG.

- IF FOST normal level indication is unavailable,
  THEN
  REFER to Attachment 10.4 for level in inches from the inside top of FOST.

- SR 3.8.2.1 allows the DG to be exempted from load testing during MODES 5 AND 6.

- Following a loss of air to the diesel generator pneumatic logic board, RESTORATION of air will require RESET of the DIESEL GENERATOR RUN/STOP MECHANICAL TRIP PRESSURE SWITCH.

  - An internal relay on the logic board will vent air until the DIESEL GENERATOR RUN/STOP MECHANICAL TRIP PRESSURE SWITCH is pushed to TRIP AND then pulled out to RUN.

- IF control air is lost (e.g., the air receiver outlet valves are closed) while the engine is in the MAINTENANCE mode,
  THEN
  the pneumatic control system will return to the Normal Mode when control air is re-established.

  - PLACE the Mode Select Switch to the MAINT position again to return the DG pneumatic control system to the MAINTENANCE mode.

5.3 Notes: (continued)

- IF the DG has started due to a Safety Injection (Emergency Start),
  THEN
  a remote Emergency Stop with the SI signal still present will cause the diesel to momentarily stop, BUT when the DG speed reaches less than 200 rpm, the engine will restart (provided at least one starting air receiver is above 150 psig).
  - RESTART of the DG can be prevented by placing the DG Emergency STOP/START handswitch in PULLOUT.
- A synchronizing check relay is installed in the manual close circuit of 1EG1 AND 1EG2 to prevent paralleling the DG out of phase when manually closing the DG output breaker.
  - This relay does NOT affect automatic closing of the breakers.
- The DG output breaker will trip AND lockout when a fault occurs on its associated bus.
  - An Emergency Start, however, will override the phase-to-ground fault (86-2).
  - The phase-to-phase bus fault (86-1) will lockout the DG output breaker with either a Normal OR Emergency Start.
- A Blackout Signal will result in an Emergency Start of the associated DG.
- The remote Emergency STOP/START handswitch contains a contact which remains CLOSED in "CENTER AFTER START".
  - This feature maintains the emergency start signal to the associated DG until momentarily returned to STOP.
- IF the Unit is in ABN-912,
  THEN
  the louvers in the 844 air compressor room will have been CLOSED as directed by OWI-912.
  - This could affect carbon monoxide levels AND heat in this area when the DG is running.
  - These louvers are CLOSED to prevent freezing of the Fire Protection Piping in the room.
  - IF CLOSED,
    THEN
    the air compressor room louvers should be REOPENED prior to Diesel start.

5.3 Notes: (Continued)

- The left AND right bank AIR START HEADER VENTs are checked for the following reasons:
  - During the run, the vents are checked to be unobstructed by noting the escape of air. A small amount of purge air is provided to the air start header from the intake air manifold during Diesel operation. This purge flow ensures that a buildup of combustible gases will NOT occur in the air start header should a cylinder head start valve develop leakby.
  - WHEN the Diesel is NOT running,
    THEN
    the vents may be checked to ensure no escape of air. An escape of air when the Diesel is NOT running indicates that an air start block valve is leaking by. (This check is NOT performed per this OPT, but is checked approximately monthly by the System Engineer.)
- The Automatic Voltage Regulator (AVR) includes voltage limiting controls to ensure the TS limits for voltage (6480-7150 V) are maintained.
  WHEN the DG is running in Emergency Mode, in Isochronous AND voltage goes above 7185V or below 6450V,
  THEN
  a voltage limiting relay (K300) will initiate a trip of the AVR AND the magnetics mode of voltage control is placed in service. The magnetics mode of operation removes voltage control capability from the Operator AND renders the DG inoperable. Therefore, when adjusting DG voltage, the following items should be considered.
  - IF the AVR TRIP light is ON,
    THEN
    the DG is to be considered inoperable until the AVR TRIP light is reset. REFERENCE Attachment 5 of SOP-609A for reset of the AVR TRIP signal.
  - IF voltage rises to 7185V,
    THEN
    the AVR will trip to magnetics mode and the AVR trip light will energize. Voltage must be lowered below 7150V to reset the AVR.
  - An AVR TRIP condition with the DG in Isochronous AND no emergency start signal will result in an 86-2 Lockout trip signal.
- During a Slow Start, frequency may vary slightly, but will remain within limits of $\geq$ 58.8 Hz AND $\leq$ 61.2 Hz per TS SR 3.8.1.2 (CR-2012-003749).

6.0 Prerequisites

6.1 The following prerequisites apply to Sections 8.1/8.5 (Train A) and 8.2/8.6 (Train B).

☒ 6.1.1 Sections 8.1, 8.2, 8.5 AND 8.6 can be performed in any MODE.

☒ 6.1.2 IF the plant is in MODES 1-4 AND the administrative controls allowed by TS 3.8.1 will be used to prevent the DG from being INOPERABLE when the DG is synchronized to a bus that is connected to Offsite Power,
THEN
ENSURE the requirements of Attachment 10.7 are met.

6.1.3 IF the plant is in MODES 1-4 AND the DG will be INOPERABLE to support testing (e.g., water roll check, slow start OR NOT using Attachment 10.7 admin controls),
THEN
PERFORM the following:

N/A ☐ A. Before rendering a DG INOPERABLE to support testing, REVIEW the LCO tracking system to verify that all required systems, subsystems, trains, components AND devices that depend on the remaining OPERABLE DG as a source of emergency power are also OPERABLE.

☐ B. Before rendering a DG INOPERABLE to support testing, REVIEW the LCO tracking system to verify the TDAFWP is also OPERABLE per TS 3.7.5.

☐ C. Before rendering a DG INOPERABLE to support testing, VERIFY that the plant is NOT operating under an ACTION Statement for an INOPERABLE offsite A.C. power source AND TS Surveillances are current for the opposite train DG per TS 3.8.1.

☒ D. INITIATE a LCOAR per ODA-308 if the DG will be rendered INOPERABLE to support testing.

[C] ☒ 6.1.4 PERFORM DG Engine Roll Water Check per Attachment 10.2 (Train A) OR 10.3 (Train B).

6.0 Prerequisites (continued)

[C] ☑ 6.1.5 NOTIFY Prompt Team that a DG run is planned. (A minimum of twenty-four hours prior notice should be given).

- IF this run is the only planned run of the selected DG this calendar month (i.e. accelerated testing is NOT in effect),
THEN
INFORM Prompt Team that the following will need to be performed:

☑ • The monthly activities required by MSM-PO-3374.

☑ • The generator brushes AND slip rings will need to be checked for proper operation.

☑ • Vibration monitoring as required by the Predictive Maintenance Program.

[C] ☑ 6.1.6 IF this run is the only planned run of the selected DG this calendar month,
THEN
INFORM Chemistry of the scheduled start time AND that the following sample collection will need to be performed per COP-609A:

- COLLECT jacket water microbial samples specified by CHM-150 prior to DG run.
- COLLECT remaining jacket water monthly samples specified by CHM-150 after the DG is running.
- COLLECT fuel oil transfer system monthly samples specified by CHM-160 (normally collected when the DG is running).

N/A 6.1.7 IF CLOSED due to OWI-912 OR ABN-912,
THEN
ENSURE the louvers in the 844' Air Compressor Room AND Day Tank Room are OPEN prior to Diesel start.

☑ 6.1.8 The DG is in an Auto Start Status per SOP-609A.

6.1.9 ENSURE the following for the Woodward Governor:

☑ • Diesel Generator Governor Setpoints are properly set per TDM-801.

☑ • Oil level in the Governor sightglass is ≥ 3/4.

6.0 Prerequisites (continued)

☑ 6.1.10 SSW is in service per SOP-501A with flow through the Jacket Water Heat Exchanger in the normal range. (1500 to 2650 gpm)

☑ 6.1.11 WHEN jacket water or lube oil temperature is less than 120°F,
THEN
EDG is rendered INOPERABLE, but is still considered available down to 40°F.
All parameters are read on multi-point indicators 1-TI-3417 (Train A) OR 1-TI-3418 (Train B).

- IF temperature is less than 120°F,
  THEN
  NOTIFY System Engineering prior to starting the DG.

☑ 6.1.12 VERIFY Lube oil AND jacket water temperatures out of the engine are ≤170°F. All parameters are read on multi-point indicators 1-TI-3417 (Train A) OR 1-TI-3418 (Train B). Temperatures ≤170°F indicate that the DG is at ambient conditions prior to test performance.

[C] ☑ 6.1.13 OBTAIN a copy of form TSP-503-1, "Emergency Diesel Generator Start/Failure Reporting Form"

☑ 6.1.14 Head set AND DG indicator cock tool are available.

☑ 6.1.15 CPU green light at Governor Panel is ON.

☑ 6.1.16 CONTACT Security prior to starting the Diesel Generator.

6.0 Prerequisites (continued)

CAUTION:
- All electronic test equipment should be battery powered OR Isolated (CR-2009-008643, EV-CR-2011-008191-1).
- WHEN connecting AND using recorders for the following parameters, THEN minimum input impedance should be 250 ohms.

NOTE:
- The recorder connected per the following step may be an eight (8) channel OR sixteen (16) recorder. The following information is written for use with a Yokagawa recorder. IF a different type of recorder is used (i.e Iotech), THEN the setup may be altered as needed to obtain the required data.
- Fast Start is only performed in Sections 8.1 AND 8.2.

NOTE: WHEN connecting AND using recorders that connect to floating plant systems/circuits, THEN the following criteria must be met (EV-CR-2011-008191-1):

- The recorder has internal battery power,

  -OR-

- The recorder is powered through the use of an isolation transformer,

  -OR-

- Supervisor approval is given to connect directly to the wall outlet.

6.1.17 IF a Fast Start is to be performed,
THEN
for the selected Diesel Generator, have Prompt Team OR other qualified personnel CONNECT AND SETUP a Yokagawa recorder (OR equivalent) as follows:

A. For the selected DG, CONNECT recorder to the following points:

DIESEL GENERATOR 1-01 (Train A DG)

- ☐ To allow trending of 1DG1 FREQUENCY, inside CP1-ECPRLV-16, EMERGENCY RESPONSE FACILITY TRANSDUCER PANEL 1-LV-16, CONNECT recorder channel one (1) to TCC-8 (+) AND TCC-7 (-).
- ☐ To allow trending of 1DG1 VOLTAGE, inside CP1-ECPRLV-16, EMERGENCY RESPONSE FACILITY TRANSDUCER PANEL 1-LV-16, CONNECT recorder channel 5 OR 9 (Channel 5 for an 8 channel recorder, channel 9 for a 16 channel recorder) to TCC-2 (+) AND TCC-1 (-).

6.0 Prerequisites (continued)

6.1.17 A. DIESEL GENERATOR 1-02 (Train B DG)

N/A • To allow trending of 1DG2 FREQUENCY, inside CP1-ECPRLV-17, EMERGENCY RESPONSE FACILITY TRANSDUCER PANEL 1-LV-17, CONNECT recorder channel one (1) to TCC-8 (+) AND TCC-7 (-).

☑ • To allow trending of 1DG2 VOLTAGE, inside CP1-ECPRLV-17, EMERGENCY RESPONSE FACILITY TRANSDUCER PANEL 1-LV-17, CONNECT recorder channel 5 OR 9 (Channel 5 for an 8 channel recorder, channel 9 for a 16 channel recorder) to TCC-2 (+) AND TCC-1 (-).

NOTE:	The attachment provides setup information in order to obtain consistent comparable data. Other setups may be used if needed.

☑ B. SETUP the recorder per Attachment 10.5, as applicable to the number of channels on the recorder used.

NOTE:	• WHEN normal DG FOST level indication is NOT available AND level is being checked using the DG FOST alternate level indication, THEN a weekly check is adequate to ensure that a ≥ 7 day Tech Spec fuel oil supply is maintained. During continuous operation of the DG, the FOST should be checked shiftly, AND should be checked following each DG run (AI-CR-2011-008822-1). • A DG uses approximately 480 gallons of fuel per hour at 7.0 MW. Approximately 1200 gallons of fuel will be used for the monthly surveillance. Approximately 12,000 to 13,000 gallons of fuel will be used for the 24 load run.

[C] ☑ 6.1.18 VERIFY that the volume of fuel in the Fuel Oil Storage Tank AND Day Tank is sufficient to support testing without dropping below the TS minimum requirements.

6.0 Prerequisites (continued)

6.1.19 To ensure that the grid is stable enough to support this test, VERIFY that the following conditions DO NOT exist:

- ☒ Energy Emergency Alert (EEA) in effect.
- ☒ Any NRC/Dept. Of Homeland Security Notification in effect for a direct threat to the Texas electrical grid.
- ☒ The transformer supplying the bus the DG will be aligned to during this test has (OR will have) less than two off-site power sources available.

6.2 The following prerequisites apply to Sections 8.3 (Train A) and 8.4 (Train B).

N/A 6.2.1 Sections 8.3 AND 8.4 can be performed in any MODE.

6.2.2 VERIFY one of the following conditions is met to use Section 8.3 OR 8.4:

N/A • The plant is operating under TS ACTION statement 3.8.1.B.

-OR-

☑ • The DG will be started AND NOT loaded for post work testing, Special testing, etc.

NOTE:	IF this section is being used to start the DG for testing other than to satisfy TS action statements (Post Work Testing, Special Tests, etc.), THEN pre-run water roll checks should be performed.

N/A 6.2.3 IF DG run is NOT required by an Action statement,
THEN
PERFORM DG Engine Roll Water Check per Attachment 10.2 (Train A) OR 10.3 (Train B).

6.2.4 ENSURE the following for the Woodward Governor:

N/A • Diesel Generator Governor Setpoints are properly set per TDM-801.

☑ • Oil level in the Governor sightglass is ≥ 3/4.

N/A 6.2.5 The DG is in an Auto Start Status per SOP-609A.

☐ 6.2.6 VERIFY that the volume of fuel in the Fuel Oil Storage Tank AND Day Tank are sufficient to support testing without dropping below the TS minimum requirements.

[C] ☑ 6.2.7 OBTAIN a copy of form TSP-503-1, "Emergency Diesel Generator Start/Failure Reporting Form"

6.2 The following prerequisites apply to Sections 8.3 (Train A) and 8.4 (Train B). (continued)

N/A 6.2.8 SSW is in service per SOP-501A with flow through the Jacket Water Heat Exchanger in the normal range. (1500 to 2650 gpm)

☐ 6.2.9 WHEN jacket water or lube oil temperature is less than 120°F,
THEN
EDG is rendered INOPERABLE, but is still considered available down to 40°F. All parameters are read on multi-point indicators 1-TI-3417 (Train A) OR 1-TI-3418 (Train B).

- IF temperature is less than 120°F,
  THEN
  NOTIFY System Engineering prior to starting the DG.

☐ 6.2.10 VERIFY Lube oil AND jacket water temperatures out of the engine are ≤170°F. All parameters are read on multi-point indicators 1-TI-3417 (Train A) OR 1-TI-3418 (Train B). Temperatures ≤170°F indicate that the DG is at ambient conditions prior to test performance.

☐ 6.2.11 CPU green light at Governor Panel is ON.

☐ 6.2.12 CONTACT Security prior to starting the Diesel Generator.

☑ 6.2.13 IF CLOSED due to OWI-912 OR ABN-912,
THEN
ENSURE the louvers in the 844 air compressor room are OPEN prior to Diesel start.

6.2.14 To ensure that the grid is stable enough to support this test, VERIFY that the following conditions DO NOT exist:

N/A • Energy Emergency Alert (EEA) in effect.

☐ • Any NRC/Dept. Of Homeland Security Notification in effect for a direct threat to the Texas electrical grid

☑ • The transformer supplying the bus the DG will be aligned to during this test has (OR will have) less than two off-site power sources available.

7.0 TEST EQUIPMENT

7.1 Two Calibrated Stopwatches, 0.1 second resolution, analog OR digital.

7.2 Clear bottle (1 liter)

7.3 Yokagawa recorder (OR equivalent) (Fast Start only)

8.0 INSTRUCTIONS

8.1 Train A Diesel Generator Monthly Operability Test

CAUTION: Section 8.3 should be performed in lieu of Section 8.1 if the plant is operating in MODE 1-4, AND the DG is being started specifically to satisfy TS ACTION statement 3.8.1.B, due to an INOPERABLE DG.

NOTE: RECORD all data on Form OPT-214A-1.

☑ A. OBTAIN permission to start the test from the Shift Manager.

☑ B. CONTACT Prompt Team to ensure that all required pre-start maintenance activities are complete (RECORD).

CAUTION:
- N/A The following step will allow the DG to "slow start" which will cause the DG to reach rated speed AND voltage in greater than 10 seconds. The DG should be considered INOPERABLE until the FAST/SLOW START handswitches have been placed in FAST.
- N/A IF the Diesel is to be started using a remote Emergency Start, THEN the LCOAR should remain in effect until completion of Step O.2). RESTORATION of Shutdown Protection following the Emergency Starts requires LOCAL control of the Diesel. The DG is INOPERABLE when placed in LOCAL.

NOTE: Prerequisite 6.1.3 should be reviewed if a time delay of several hours has occurred between Water Rolls AND placing the switches in SLOW START.

C. IF a Slow Start will be performed,
THEN
PLACE both of the following switches in SLOW:

- N/A ☐ 1-HS-3413-5, DIESEL GENERATOR 1-01 CHANNEL I FAST/SLOW START HANDSWITCH
- ☑ 1-HS-3419-5, DIESEL GENERATOR 1-01 CHANNEL II FAST/SLOW START HANDSWITCH

8.1

CAUTION: IF the DG is being auto started using a slave relay, THEN the start channel for that relay must be enabled. Additionally, the air receiver interlocked with that channel must be in service with pressure greater than 150 psig.

Slave Relay	Start Channel	Breakers	Receiver	Surveillance
1-K603-A	I	CB1/CB2	02	OPT-465A
1-K609-A	II	CB3/CB4	01	OPT-467A

NOTE: IF a Local Normal Start OR Local Emergency Start will be used to start the DG, N/A THEN PERFORM appropriate section of SOP-609A.

CAUTION: DO NOT RUN the Auxiliary Lube Oil Pump in HAND for more than one minute per shift with the DG NOT running. This is to prevent flooding the turbochargers with oil.

[C] D. RUN the Auxiliary Lube Oil pump to prelube the DG as follows:

☐ 1) Approximately TWO minutes prior to DG startup, PLACE 1-HS-3411-1, AUXILIARY LUBE OIL PUMP in HAND.

CAUTION: DG should be started immediately (0-120 sec.) after stopping the Auxiliary Oil pump.

☐ 2) WHEN you have the following indications:

- 1-PI-3411-1B, LUBE OIL PRESS ≥40 psig
- 1-PI-3411-3A,TURBO OIL PRESS LB ≥15 psig
- 1-PI-3411-3B,TURBO OIL PRESS RB ≥15 psig

THEN
STOP the Auxiliary Oil pump AND PLACE 1-HS-3411-1, AUXILIARY LUBE OIL PUMP in AUTO.

8.1

CAUTION:
- All DG automatic shutdown protection except overspeed AND generator differential are deactivated on an emergency start.
- A Slow Start verifies the DG starts from standby condition AND achieves steady state voltage ≥ 6480 V AND ≤ 7150 V AND frequency ≥ 58.8 Hz AND ≤ 61.2 Hz per TS SR 3.8.1.2.
- Steps E.1) AND E.2) should be performed simultaneously.

NOTE: DG Slow Start is timed for information purposes only.

E. IF a Slow Start is desired,
THEN
PERFORM the following:

1) Within 120 seconds after stopping the Auxiliary Lube Oil pump, START the DG by performing ONE of the following steps:

N/A ☐ • INDUCE an automatic start by simulating an auto start condition in accordance with an approved test procedure meeting the requirements of TS 3.8.1.2 AND 3.8.1.7.

-OR-

☐ • Momentarily PLACE CS-1DG1N, DG 1 NORM STOP/START switch to START.

-OR-

☐ • Momentarily PLACE CS-1DG1E, DG 1 EMER STOP/START switch to START.

☐ 2) Using a stopwatch, TIME the Diesel Generator start from time of start signal until the lower limits of frequency AND voltage are reached. (RECORD)

☑ 3) VERIFY frequency AND voltage stable AND RECORD steady state DG parameters required by the data sheet.

8.1

CAUTION:

- All DG automatic shutdown protection except overspeed AND generator differential are deactivated on an emergency start.
- A Fast Start verifies the DG starts from standby condition AND achieves in ≤ 10 seconds, voltage ≥ 6480 V AND frequency ≥ 58.8 Hz. Also, DG steady state voltage is verified ≥ 6480 V AND ≤ 7150 V AND frequency ≥ 58.8 Hz AND ≤ 61.2 Hz per TS SR 3.8.1.7.
- Steps F. 2), F. 3) AND F. 4) shall be performed simultaneously.

NOTE:

- IF a Fast Start is being performed, THEN two operators, each with a separate stopwatch, should time the start. The time on the primary stopwatch should be recorded unless invalidated by stopwatch malfunction OR operator error. IF the primary stopwatch time is invalid, THEN RECORD the time on the backup stopwatch.
- The recorder trace is for information purposes AND allows for monitoring the time for the DG to reach steady state operation. The recorder trace allows for trend evaluation to identify degradation of governor AND voltage regulator performance.

F. IF a Fast Start is desired,
THEN
PERFORM the following:

☑ 1) ENSURE 1-HS-4393, DG 1 CLR SSW RET VLV ALIGNED in AUTO (CLOSE). (RECORD)

☑ 2) Simultaneous with DG start signal, PRESS the RECORDER START/STOP key on the recorder.

☑ 3) Using stopwatches, TIME the Diesel Generator start from time of diesel start signal until the lower limits of frequency AND voltage are BOTH reached. (RECORD)

8.1 F. 4) Within 120 seconds after stopping the Auxiliary Lube Oil pump, START the DG by performing ONE of the following steps:

N/A • INDUCE an automatic start by simulating an auto start condition in accordance with an approved test procedure meeting the requirements of TS 3.8.1.2 AND 3.8.1.7.

-OR-

☑ • Momentarily PLACE CS-1DG1N, DG 1 NORM STOP/START switch to START.

-OR-

N/A • Momentarily PLACE CS-1DG1E, DG 1 EMER STOP/START switch to START.

☑ 5) VERIFY diesel frequency AND voltage stabilize.

☑ 6) WHEN ≥ 20 seconds have elapsed following DG start signal, THEN STOP the recorder.

☑ 7) RECORD stable DG parameters required by the data sheet.

☑ 8) VERIFY 1-HS-4393, DG 1 CLR SSW RET VLV - OPEN. (RECORD).

☑ 9) NOTIFY personnel to disconnect the recorder.

> NOTE: IF conditions hazardous to personnel OR equipment develop, THEN the DG can be immediately shutdown by placing the Emergency STOP/START switch in PULLOUT. This does NOT require that the output breaker be opened first.

☑ G. VERIFY 1-HS-3411-1, AUXILIARY LUBE OIL PUMP is in AUTO AND ENSURE the pump is STOPPED.

H. PERFORM the following to STOP the AUXILIARY JACKET WATER PUMP:

☑ 1) PLACE 1-HS-3415-1, AUXILIARY JACKET WATER PUMP momentarily in OFF.

☑ 2) RETURN 1-HS-3415-1, AUXILIARY JACKET WATER PUMP to AUTO.

☑ 3) VERIFY the pump STOPS.

8.1

N/A I. IF the DG voltage does NOT build up to 6900V (6480-7150),
THEN
TAKE CS-1DG1E, DG 1 EMER STOP/START to PULLOUT AND NOTIFY Maintenance to investigate the cause of the failure.

> **CAUTION:**
> - DO NOT RUN the Diesel Generator at steady state speeds less than 440 RPM.
> - [C] MINIMIZE unloaded operation of the DG. (≤ 5 minutes recommended).

> **NOTE:** Steps J. through O. may be performed in parallel. WHEN local steps are complete, THEN the Operator should re-establish communications with the Control Room.

J. CHECK the following initial operating parameters on Local Engine Control Panel 1-DG-01A.

	INSTRUMENT	VALUE
☑ •	1-PI-3411-1B, LUBE OIL PRESS	40-80 psig
☑ •	1-PI-3411-3A, TURBO OIL PRESS LB	20-40 psig
☑ •	1-PI-3411-3B, TURBO OIL PRESS RB	20-40 psig
☑ •	1-PI-3415-1, JACKET WATER PRESS	10-30 psig
☑ •	1-PI-3409-3, FUEL OIL PRESS (ENG. PMP-BLACK POINTER)	20-60 psig
☑ •	1-SI-3413B-3, ENGINE SPEED	440-460 rpm

☑ K. PERFORM a general inspection of the Diesel Generator for any obvious problems.

NOTE: The acceptance criteria for the following fans is that all fans are running, unless the Control Room handswitches have been intentionally placed in PULLOUT OR MCC breakers have been intentionally placed in OFF. IF outside air temperature is below 76.7°F, THEN at least one vent fan handswitch must be in AUTO to satisfy DG operability.

8.1 K.1) VERIFY appropriate ventilation units RUNNING (handswitch Red Light LIT).

- ☒ 1-HS-5691A-1, DGFO DAY TK AREA VENT FAN 4
- ☒ 1-HS-5691B-1, DG 1 RM VENT FN 25
- ☒ 1-HS-5691C-1, DG 1 RM VENT FN 26
- ☒ 1-HS-5691D-1, DG 1 RM VENT FN 27
- ☒ 1-HS-5691E-1, DG 1 RM VENT FN 28

☒ K.2) VERIFY 1-ALB-11B/3.16, ANY DG RM FN ΔP LO alarm is CLEAR.

NOTE:

- A DG Room Ventilation Fan is determined to be OPERATING when the handswitch Red Light is LIT AND the DG RM FN ΔP LO alarm is CLEAR. (CR-2014-001579)
- IF DG RM FN ΔP LO alarm is NOT functional, THEN Fans may be determined OPERATING by verifying each running fan local PIS (1-PIS-5693A/B/C/D/E) indicates greater than ALM alarm setpoint AND documenting verification in the form comments.

L. RECORD appropriate ventilation units are OPERATING.

- ☒ 1-HS-5691A-1, DGFO DAY TK AREA VENT FAN 4
- ☒ 1-HS-5691B-1, DG 1 RM VENT FN 25
- ☒ 1-HS-5691C-1, DG 1 RM VENT FN 26
- ☒ 1-HS-5691D-1, DG 1 RM VENT FN 27
- ☒ 1-HS-5691E-1, DG 1 RM VENT FN 28

8.1

> CAUTION:
> - The DG is considered INOPERABLE until the FAST/SLOW START handswitches are placed in FAST.
> - IF the Diesel was started using a remote Emergency Start, THEN the LCOAR should remain in effect until completion of Step O.2). RESTORATION of Shutdown Protection following the Emergency Starts requires LOCAL control of the Diesel. The DG is INOPERABLE when placed in LOCAL.

[IV] M. IF a Slow Start was performed,
THEN
PLACE both of the following switches in FAST:

N/A ☐ • 1-HS-3413-5, DIESEL GENERATOR 1-01 CHANNEL I FAST/SLOW START HANDSWITCH

☑ • 1-HS-3419-5, DIESEL GENERATOR 1-01 CHANNEL II FAST/SLOW START HANDSWITCH

> NOTE: The Normal Start may have been local OR remote. Step O. provides instructions for reinstating full shutdown protection if an Emergency Start was performed.

☐ N. IF a Normal Start was initiated,
THEN
VERIFY SHUTDOWN SYS ACTIVATED light is ON.

O. IF an Emergency Start was performed AND it is desired to reinstate full shutdown protection,
THEN
PERFORM the following as applicable:

1) IF a local emergency manual start was initiated,
THEN
PERFORM the following:

N/A ☐ a) PLACE 1-HS-3413-4B, LOCAL EMERG. STOP/OFF/START in the CENTER (AUTO) position.

☑ b) VERIFY SHUTDOWN SYS ACTIVATED light is ON.

8.1

CAUTION: Placing the MASTER SWITCH (RLMS) in LOCAL renders the DG INOPERABLE.

O. 2) IF a remote emergency manual start was initiated,
THEN
PERFORM the following:

N/A ☐ a) PLACE 1-HS-3413-3B, MASTER SWITCH (RLMS) in LOCAL.

☐ b) Momentarily PLACE CS-1DG1E, DG 1 EMER STOP/START in STOP.

☐ c) RETURN 1-HS-3413-3B, MASTER SWITCH (RLMS) to REMOTE.

☑ d) VERIFY SHUTDOWN SYS ACTIVATED light is ON.

3) IF a remote automatic start was initiated by a Slave Relay Test,
THEN
PERFORM the following:

N/A a) RESET the Slave Relay Test per the applicable procedure.

NOTE: The following step verifies full shutdown protection is restored AND duplicates the verification requirements of the Slave Relay Test.

b) VERIFY the following:

N/A • Diesel is RUNNING.

☑ • SHUTDOWN SYS ACTIVATED light is ON.

P. VERIFY the following lights are ON:

☑ • RUNNING LIGHT

☑ • READY TO LOAD light

8.1

NOTE: SR 3.8.2.1 allows for the DG to be exempted from load testing during MODES 5 AND 6. However, the DG should be loaded to greater than 3.5 MW for at least one hour during each run, regardless of plant MODE.

☐ Q. TURN SS-1EG1, BKR 1EG1 SYNCHROSCOPE to ON.

NOTE: Use of V-IN AND V-RUN to adjust voltage prior to synchronization is the preferred method. This method adjusts DG voltage approximately 50 to 100 volts greater than 1EA1 voltage. The following equipment metering is available as an alternate method.

DG Voltage		SFGD Bus Voltage
V-1EG1, DG 1 VOLT (CB-11) OR V6710A, DG 1 VOLT (Computer Pt.)	TO	V-1EA1-1, BUS 1EA1 VOLT (CB-11) OR V6101A, BUS 1EA1 VOLT (Computer Pt.)

NOTE: DG VOLT should be maintained less than 7150V per Technical Specifications. WITH the AVR TRIP light ON (on at 7185V), the DG is to be considered INOPERABLE until the AVR TRIP light is reset. REFERENCE Attachment 5 of SOP-609A for reset of the AVR TRIP signal.

☐ R. Using 90-1EG1, DG 1 VOLT CTRL, gradually ADJUST V-IN on the synchroscope 1 to 2 volts higher than V-RUN on the synchroscope.

☐ S. Using 65-1EG1, DG 1 SPD CTRL, ADJUST speed so the synchroscope is moving 2 to 4 RPM in the fast direction.

8.1

> NOTE: **"Continuous Action Step"** This step is a compensatory action for the possibility of excessive loading on the DG due to Offsite Power degradation. The termination criteria of Attachment 10.7, Section II apply to the following step.

T. IF the termination criteria of Attachment 10.7, Section II are met while the DG is synchronized with the offsite power source,
THEN
PERFORM the following:

☐1) OPEN CS-1EG1, DG1 BKR 1EG1.

☐2) Slowly ADJUST DG voltage to 6900 V (6831 V to 6969 V).

☐3) Slowly ADJUST DG frequency to 60.0 (59.7 to 60.3) Hz.

> CAUTION: Following DG Output Breaker closure, load should be raised promptly to prevent Reverse Power Trip. The DG will trip if the Generator is motorized with >34.5 KW IN for greater than 8 seconds.

U. To synchronize the Diesel Generator to the bus, PERFORM the following:

☐1) CLOSE CS-1EG1, DG 1 BKR 1EG1 when the synchroscope is slightly before the 12 o'clock position AND moving slowly in the fast direction.

☐2) Immediately LOAD the DG to 2.2 - 2.5 MW for stability by moving 65-1EG1, DG 1 SPD CTRL in the RAISE direction.

☐ V. TURN SS-1EG1, BKR 1EG1 SYNCHROSCOPE to OFF.

☐ W MAINTAIN 0-500 KVAR out by adjusting 90-1EG1, DG 1 VOLT CTRL while continuing with this procedure.

[C] X. INITIATE form TSP-503-1 AND NOTIFY the organizations listed below that the DG has been started:

☐• INITIATE TSP-503-1

☐• Prompt Team

☐• Chemistry

8.1

CAUTION:
- DO NOT EXCEED 6.0 MW until the DG load is 6.0 MW AND the DG has been running 45 minutes OR load has been maintained at 6.0 MW for at least 15 minutes.
- Grid induced load swings may cause DG load to exceed 6.0 MW prior to meeting the necessary run-time. IF this occurs, THEN DG load should be promptly adjusted back to 6.0 MW.

NOTE:
- IF an SI occurs while paralleled to OFFSITE, THEN the DG Output Breaker will OPEN AND the DG will continue to run.
- IF conditions hazardous to personnel OR equipment develop, THEN the DG can be immediately SHUTDOWN by placing the Emergency STOP/START Switch in PULLOUT. This does NOT require that the output breaker be opened first.

☐ Y. LOAD the DG to 6.0 MW over the next 20 minutes using 65-1EG1, DG 1 SPD CTRL, unless otherwise directed by the Shift Manager.

NOTE: DG load should be maintained as close to 6.4 MW as practical to ensure consistent data is taken for each DG run.

Z. WHEN DG load has been stabilized at 6.0 MW for 15 minutes OR load is at 6.0 MW AND DG has been running ≥45 minutes,
THEN:

☐1) RAISE load to 6.4 MW (6.3 to 7.0 MW).

☐2) RECORD time rated load is reached.

☐3) NOTIFY Prompt Team AND Chemistry that the DG is at full load.

8.1

NOTE: 1-PI-3417-8 is located inside the rear doors of the Local Engine Control Panel.

[C] ☐ AA. RECORD control air pressure as indicated at 1-PI-3417-8, DIESEL GENERATOR 1-01 GROUP I TRIPS PRESSURE INDICATOR.

NOTE: The AIR START HEADER VENT(s) are located on the left AND right bank of the DG at the Turbo end of the Catwalk.

[C][L] ☐ AB. ENSURE that the left AND right bank AIR START HEADER VENT are unobstructed by noting the escape of air.

NOTE: The DG should be operated as close to 6.4 MW as practical. Excursions for short periods of time outside the 6.3 to 7.0 MW range are acceptable AND shall NOT invalidate this test.

☐ AC. OPERATE the DG at 6.4 MW (6.3 to 7.0 MW) for at least 60 minutes (RECORD).

NOTE: Time at full load is recorded to verify that the DG was loaded for $\geq$60 minutes AND is NOT intended to be the total time at full load.

☐ AD. RECORD the time of the end of full load test. CALCULATE the total run time at Full load (6.3 to 7.0 MW) (RECORD).

[C]

NOTE: IF the DG will continue to operate at steady load, THEN a full set of DG Operating logs should be taken every 4 hours while the DG is at steady load.

☐ AE. At least 60 minutes after the time recorded in Step 8.1 Z.2), TAKE a full set of Diesel Operating logs prior to reducing load on the DG below 6.4 MW.

8.1

> NOTE: Diesel Generator Engine Balancing (Firing Pressures) is usually an outage maintenance activity.

☐ AF. IF Diesel Generator Engine Balancing (Firing Pressures) is to be performed, THEN GO to SOP-609A.

> NOTE: The unloading rates of this procedure should be followed unless otherwise directed by the Shift Manager OR a more rapid unloading rate is required to support testing such as hot web deflection measurements. When rapid shutdown of the diesel is required, Step AG. may be marked N/A.

☐ AG. LOWER DG load to 2.2 to 2.5 MW over 20 minutes using 65-1EG1, DG 1 SPD CTRL, unless otherwise directed by the Shift Manager.

☐ AH. MAINTAIN DG load stable at 2.2 to 2.5 MW for approximately 10 minutes while performing Steps AI., AJ. AND AK.

> NOTE: The responsible group will determine if a specific activity is required for this run.

AI. CONTACT the organizations listed below to ensure that all maintenance activities required prior to DG shutdown are complete (RECORD):

☐ • Prompt Team

☐ • Chemistry

[C] ☐ AJ. Visually INSPECT the jacket water standpipe, pump suction AND engine return nozzle welds for cracking OR leakage.

8.1

NOTE:
- Lube oil pressure ≥45 psig verifies 1DO-0158 is CLOSED AND 1DO-0157 is OPEN.
- Jacket Water Keep Warm Pump NOT rotating verifies 1DO-0104 is CLOSED.

AK. RECORD 1-PI-3411-1B, LUBE OIL PRESS AND PERFORM the following:

- ☐ VERIFY LUBE OIL PRESS ≥45 psig AND RECORD that 1DO-0158 is CLOSED.
- ☐ VERIFY LUBE OIL PRESS ≥45 psig AND RECORD that 1DO-0157 is OPEN.
- ☐ VERIFY the JACKET WATER KEEP WARM PUMP is NOT rotating AND RECORD that 1DO-0104 is CLOSED.

☐ AL. DECREASE DG load to approximately 0.5 MW using 65-1EG1, DG 1 SPD CTRL.

☐ AM. LOWER KVAR to approximately zero by using 90-1EG1, DG 1 VOLT CTRL.

[C]

CAUTION: MINIMIZE unloaded operation of the DG (≤5 minutes recommended).

☐ AN. OPEN CS-1EG1, DG 1 BKR 1EG1.

☐ AO. VERIFY SHUTDOWN SYS ACTIVATED light is ON.

NOTE: IF rapid shutdown of the diesel is required, THEN the following step may be marked N/A.

☐ AP. ALLOW the Diesel Generator to run unloaded for several minutes to allow engine temperatures to become more stable. (REFER to CAUTION preceding Step AN.)

☐ AQ. PLACE 1-HS-3411-1, AUXILIARY LUBE OIL PUMP in OFF.

NOTE: Control air pressure is read on 1-PI-3417-8, located inside the rear door of the Local Engine Control Panel.

[C] ☐ AR. STATION an Operator to observe control air pressure during Diesel SHUTDOWN (per Step AT.).

8.1

> NOTE:
> - The Normal STOP/START switch only needs to be turned to STOP momentarily. However, the green light on the handswitch module will NOT illuminate until engine speed is less than 200 rpm.
> - Following shutdown of the Diesel Generator, there is a delay of approximately 2 minutes before the diesel will accept a Normal start. An Emergency start is still available.

AS. STOP DG 1-01 as follows:

☐ 1) PLACE CS-1DG1N, DG 1 NORM STOP/START to STOP

☐ 2) SHUTDOWN the DG Vent Fans, when requested OR as necessary, per SOP-809A.

[C] ☐ AT. OBSERVE control air pressure at 1-PI-3417-8, DIESEL GENERATOR 1-01 GROUP I TRIPS PRESSURE INDICATOR during engine shutdown AND RECORD the minimum pressure during engine shutdown.

☐ AU. VERIFY Auxiliary Jacket Water Pump STOPS when speed decreases to less than 200 RPM.

☐ AV. WHEN the engine has coasted to a STOP,
THEN
PLACE 1-HS-3411-1, AUXILIARY LUBE OIL PUMP in AUTO AND VERIFY the pump is stopped.

☐ AW. RECORD 1-LI-3379, DIESEL GENERATOR FUEL OIL DAY TANK 1-01 LEVEL.

[C] AX. RECORD DG 1-01 FOST level using one of the following:

☐ • 1-LIT-3395, DIESEL GENERATOR FO STORAGE TANK 1-01 LEVEL

-OR-

☐ • Attachment 10.4, DG FOST ALTERNATE LEVEL DETERMINATION

8.1

> NOTE:
> - Waste oil accumulated during performance of the next step will be processed out of the RCA as directed in Section 9.0, Restoration.
> - Steps in procedure may be continued while waiting for sample to settle out.

[C] AY. DRAIN accumulated water from the fuel oil day tank as follows:

1) UNCAP AND CYCLE the drain valve to obtain a day tank fuel oil sample.

		OPEN	CLOSE
• 1DO-0410,	DG 1-01 FO DAY TK 1-01 TC VLV	☐	☐

[IV] ☐ 2) ENSURE that 1DO-0410 is CLOSED AND CAPPED.

☐ 3) ALLOW 5 minutes for the sample to settle out.

> NOTE: IF there was no water in the first sample, THEN RECORD zero in Step 5).

☐ 4) IF the sample is NOT water-free, NOTE the amount of water,
THEN
REPEAT Steps 1), 2) AND 3).

☐ 5) RECORD the approx. TOTAL quantity of water obtained in the sample(s).

6) IF water-free fuel oil sample cannot be obtained,
THEN

- ☐ DECLARE the DG INOPERABLE per TS. 3.8.1 OR 3.8.2 as applicable.
- ☐ INITIATE a Work Request.

8.1 AZ. RECORD Starting Air Receiver pressures from the Local Engine Control Panel AND that at least ONE receiver is ≥184 PSIG.

- ☐ • 1-PI-3421-1A, DIESEL GENERATOR 1-01 LEFT BANK AIR COMPRESSOR 1-02 AIR PRESSURE IND
- ☐ • 1-PI-3421-1B, DIESEL GENERATOR 1-01 RIGHT BANK AIR COMPRESSOR 1-01 AIR PRESSURE IND

☐ BA. PROCEED to Section 9.0, Restoration.

COMMENTS ______________________________

____

____

ATTACHMENT 10.7
PAGE 1 OF 3

TS 3.8.1 ADMINISTRATIVE REQUIREMENTS AND TEST TERMINATION CRITERIA

IF a DG will be synchronized with offsite power for the purpose of surveillance testing in MODES 1, 2, 3, OR 4 AND it is desired to maintain the DG OPERABLE,
THEN
these administrative controls are required to be used.

NOTE:	This attachment is to be used as a pre-brief checklist, as a turn-over tool for the DG RO, AND is to be referenced throughout the DG run.

I. Prior to DG start, PERFORM the following:

☑ A. ENSURE no Severe Thunderstorm OR Tornado Warning is in effect per ABN-907 "Severe Weather".

☑ B. CONTACT Transmission Grid Controller (TGM) at phone number (214)743-6920 to ensure the local electric grid is stable. ASK the controller if they would notify CPNPP prior to performing a grid voltage reduction greater than 5KV within the next four (4) hours during the monthly test OR within the next 24 hours for the 24 hour load test.

☑ C. ENSURE no activities in the switchyard will be performed that may impact the test.

☑ D. REVIEW the LCO tracking system to verify that all required systems, subsystems, trains, components AND devices that depend on the remaining OPERABLE DG as a source of emergency power are also OPERABLE.

☑ E. REVIEW the LCO tracking system to verify the TDAFWP is also OPERABLE per TS 3.7.5.

☑ F. VERIFY that the plant is NOT operating under an ACTION Statement for an INOPERABLE offsite A.C. power source AND TS Surveillances are current for the opposite train DG per TS 3.8.1

G. ENSURE ALL 6.9KV Safeguards buses (BOTH UNITS)are supplied from the preferred source by ensuring all of the following breakers are closed:

- ☑ CS-1EA1-1 INCOMING BKR 1EA1-1
- ☑ CS-1EA2-1 INCOMING BKR 1EA2-1
- ☑ CS-2EA1-1 INCOMING BKR 2EA1-1
- ☑ CS-2EA2-1 INCOMING BKR 2EA2-1

ATTACHMENT 10.7
PAGE 2 OF 3

TS 3.8.1 ADMINISTRATIVE REQUIREMENTS AND TEST TERMINATION CRITERIA

H. ENSURE Unit 1 6.9KV Safeguards bus voltages are ≥ 6750 volts (RECORD). This number will be used as part of the termination criteria of Section II. CIRCLE the source of the voltage:

☒ • V-1EA1-1, BUS 1EA1 VOLT (CB-11) -OR-

V6101A, BUS 1EA1 VOLT (Computer Pt.) 6900

☒ • V-1EA2-1, BUS 1EA2 VOLT (CB-11) -OR-

V6112A, BUS 1EA2 VOLT (Computer Pt.) 6900

II. The following test termination criteria apply during the time period that the tested DG is synchronized with an offsite source. These test termination criteria should be reviewed prior to the test start AND anytime the principal individuals responsible for the test performance (e.g., Unit Supervisor, Reactor Operator) are relieved.

TERMINATE the test if any of the following conditions occur:

☐ A. Unit 1 Reactor trips.

☐ B. The tested DG steady state load exceeds the limit established for the test (e.g. 7MW for Sections 8.1/8.2 OR 7.7MW for Sections 8.5/8.6). Momentary transients outside of the load range DO NOT invalidate this test. The operator should attempt to return load to the required range before terminating the test.

☐ C. The tested DG requires frequent OR continuous adjustment to lower its load in order to maintain the specified test load.

☐ D. The tested DG KVAR exceeds 5000 KVAR.

☐ E. The associated bus steady state voltage for the tested DG lowers ≥ 200v.

☐ F. The associated bus steady state frequency for the test DG is ≤ 59 Hz.

ATTACHMENT 10.7
PAGE 3 OF 3

TS 3.8.1 ADMINISTRATIVE REQUIREMENTS AND TEST TERMINATION CRITERIA

III. **IF test termination is required,**
THEN
PERFORM the following:

☐ A. OPEN the DG output breaker:

☐ B. Slowly ADJUST DG voltage to 6900 V (6831 V to 6969 V).

☐ C. Slowly ADJUST DG frequency to 60.0 (59.7 to 60.3) Hz.

IV. IF the AVR TRIP light is present on the AVR panel,
THEN
PERFORM Attachment 5 of SOP-609A to reset.

COMMENTS ______________________________

____

____

TRAIN A DIESEL GENERATOR OPERABILITY DATA SHEET

NOTE:	This form is used to record test data as required by Section 8.1 of OPT-214A.

STEP		OBSERVED	ACCEPTANCE CRITERIA	INITIAL
6.1.4	ENGINE ROLL WATER CHECK PER ATTACHMENT 10.2			
Att 10.2 Y.	QUICK RELEASE PIN INSTALLED IN LOCKING PIN	N/A	N/A	JR RN VERIFIED
AB.	AIR RECEIVER OUTLET VALVE CLOSED	1DO-0033/1DO-0034	N/A	JR
AE.	START AIR VALVE STROKE TESTED	VLV: 1DO-0176	N/A	JR
	AND RESULTS	SAT/UNSAT	NOTE 1	JR
AF.	OPEN AIR RECEIVER OUTLET CLOSED IN STEP AB	N/A	N/A	JR
AG.	VERIFY BOTH AIR RECEIVER OUTLET VALVES OPEN	N/A	N/A	JR INITIAL RN VERIFIED
AI.	VERIFY ALL CYLINDER INDICATOR TEST COCKS CLOSED	N/A	N/A	JR INITIAL RN VERIFIED
AJ.3) AK.	1-HS-3419-1A, MODE SELECT IN NORMAL	N/A	N/A	JR RN VERIFIED
AL.	1-HS-3413-3B, MASTER SWITCH (RLMS) IN REMOTE	N/A	N/A	JR RN VERIFIED
6.1	PREREQUISITES MET	N/A	N/A	JR

NOTE 1 The stroke test is acceptable if the engine rolls for a minimum of two complete revolutions.

<u>TRAIN A DIESEL GENERATOR OPERABILITY DATA SHEET</u>

STEP		OBSERVED	ACCEPTANCE CRITERIA	INITIAL
8.1 B.	PRE-START MAINT COMPLETE	N/A	N/A	JR
F. 1)	1-HS-4393, DG 1 CLR SSW RET VLV	AUTO (CLOSE) / AUTO (OPEN)	AUTO (CLOSE)	JR
E.2)/F.3)	TIME	6.1 SECONDS	≤10 SEC (Note 2)	JR
E.3)/F.7)	DIESEL PARAMETERS			
	• SPEED	450 RPM	≥ 441 RPM	JR
	• FREQUENCY	60.0 Hz	58.8 to 61.2 Hz	JR
	• VOLTAGE	6900 V	6480-7150 V	JR
F. 8)	1-HS-4393, DG 1 CLR SSW RET VLV	OPEN / CLOSE	OPEN	JR
L.	VENTILATION UNITS OPERATING			
	1-HS-5691A-1	ON/OFF	NOTE 3	JR
	1-HS-5691B-1	ON/OFF	NOTE 3	JR
	1-HS-5691C-1	ON/OFF	NOTE 3	JR
	1-HS-5691D-1	ON/OFF	NOTE 3	JR
	1-HS-5691E-1	ON/OFF	NOTE 3	JR
M.	1-HS-3413-5	FAST/SLOW	FAST (Note 4)	JR RN VERIFIED
	1-HS-3419-5	FAST/SLOW	FAST (Note 4)	JR RN VERIFIED
Z.2)	TIME RATED LOAD REACHED	______	N/A	______
AA.	1-PI-3417-8, CONTROL AIR PRESS DURING RUN	______ PSIG	N/A	______
AC.	OPERATE DG AT REQUIRED LOAD	______ MW	6.3-7.0 MW (Note 5)	______

TRAIN A DIESEL GENERATOR OPERABILITY DATA SHEET

STEP			OBSERVED	ACCEPTANCE CRITERIA	INITIAL
8.1	AD.	TIME AT END OF FULL LOAD TEST	______	N/A	______
		RUN TIME	______ MIN	$\geq$60 MIN (Note 5)	______
	AI.	MAINT REQUIRED PRIOR SHUTDOWN COMPLETE	N/A	N/A	______

NOTE 2 10 second acceptance criteria is not applicable if a Slow Start is performed, but should be recorded for information.

NOTE 3 The acceptance criteria is all fans running unless the Control Room handswitches have been intentionally been placed in the PULL OUT <u>OR</u> MCC breakers have been intentionally placed in OFF.

NOTE 4 Not required if FAST start performed.

NOTE 5 Acceptance criteria not applicable in MODE 5 or 6.

TRAIN A DIESEL GENERATOR OPERABILITY DATA SHEET

STEP			OBSERVED	ACCEPTANCE CRITERIA	INITIAL
8.1	AK.	1-PI-3411-1B, LUBE OIL PRESS	_______ PSIG	N/A	_____
		1DO-0158 FULL CLOSED STROKE TEST	SAT/UNSAT	≥45 PSIG	_____
		1DO-0157 FULL OPEN STROKE TEST	SAT/UNSAT	≥45 PSIG	_____
		JACKET WATER KEEP WARM PUMP NOT ROTATING	NO ROTATION/ ROTATION	N/A	_____
		1DO-0104 FULL CLOSED STROKE TEST	SAT/UNSAT	NO ROTATION	_____
	AT.	1-PI-3417-8, MINIMUM CONTROL AIR PRESSURE DURING SHUTDOWN	_______ PSIG	N/A	_____
	AW.	DAY TANK LEVEL	_________	≥3/4	_____
	AX.	STORAGE TANK LEVEL	_________ GAL	NOTE 6	_____
Att 10.4.I.		FUEL OIL STORAGE TANK SAMPLE COVER	INSTALLED (Note 7)	N/A	_____ VERIFIED
	AY.2)	ENSURE 1DO-0410 CLOSED AND CAPPED	N/A	N/A	_____ VERIFIED
	AY.5)	APPROXIMATE QUANTITY OF WATER DRAINED TO OBTAIN WATER-FREE FUEL OIL	_________ Oz.	N/A	_____
	AZ.	● 1-PI-3421-1A, LEFT BANK AIR PRESSURE	_________PSIG	N/A	_____
		● 1-PI-3421-1B, RIGHT BANK AIR PRESSURE	_________PSIG	N/A	_____
		● ONE AIR RECEIVER PRESSURE ≥ 184 PSIG	SAT/UNSAT	1-PI-3421-1A OR 1-PI-3421-1B, ≥ 184 PSIG	_____

NOTE 6 In MODES 1 - 6, ≥86,000 GAL (≤63").

NOTE 7 Step only applicable if sample cover was removed.

TRAIN A DIESEL GENERATOR OPERABILITY DATA SHEET

9.0 RESTORATION — INITIAL

A. HANDSWITCH ALIGNMENT VERIFICATION COMPLETE (OPT-214A-2) ______

ELECTRICAL LINEUP VERIFICATION COMPLETE (OPT-214A-3) ______

B. SSII LIGHT, DG PWR, OFF ______

F. TSP-503-1 SUBMITTED TO SYSTEM ENGINEERING ______

H. RECORDER TRACES ATTACHED (for Fast Start only) ______

COMMENTS/DISCREPANCIES: ______

CORRECTIVE ACTIONS: ______

PERFORMED BY: ______ DATE: Today
SIGNATURE

TEST REVIEWED: ______ DATE: ______
OPERATIONS MANAGEMENT

Facility: CPNPP JPM # NRC S-7 Task # RO1827 K/A # 016 A2.01 3.0 / 3.1 SF-7

Title: Respond to Turbine Impulse Pressure Instrument Malfunction

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	______
Actual Performance:	X	Simulator:	X
Alternate Path:	______	Plant:	______
Time Critical:	______		

READ TO THE EXAMINEE

I will explain the Initial Conditions, which steps to simulate or discuss, and provide an Initiating Cue. When you complete the task successfully, the objective for this JPM will be satisfied.

Initial Conditions: Given the following conditions:

- Unit 1 is in MODE 1 at 100% power.
- You are the Reactor Operator.

Initiating Cue: The Unit Supervisor directs you to PERFORM the following:

- RESPOND to any alarms.

Task Standard: UTILIZED ABN-709 and PLR 2007-0165, PLACED Rod Control in manual; DISABLED then RESTORED Steam Dump Valves, TRANSFERRED Turbine Impulse Pressure to an Operable Channel, and RESTORED Steam Dump System to automatic operation.

Ref. Materials: ALM-0064A, 1-ALB-6D, Window 1.10, AVE TAVE-TREF DEV, Rev. 6.

ABN-709, Steam Line Pressure, Steam Header Pressure, Turbine 1st Stage Pressure and Feed Header Pressure Instrument Malfunction, Rev. 9.

PLR 2009-0078-S, Transferring the Steam Dump System to the Steam Pressure Mode Job Aid.

Validation Time: 10 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ________________________________ Date: ______________

SIMULATOR SETUP

SIMULATOR OPERATOR:

INITIALIZE to IC-18 or any 100% power Initial Condition and LOAD Scenario File "CPNPP 2017 NRC JPM S-7" or PERFORM the following:

- **INSERT malfunction RX09A, Main Turbine 1st Stage Pressure Transmitter failure [PT-505A] to 0% on Key 1.**
- **ENSURE Rod Control is in AUTO.**

SIMULATOR OPERATOR NOTE: PERFORM the following after each JPM:

- **ENSURE PLR 2009-0078-S, Transferring the Steam Dump System to the Steam Pressure Mode Job Aid for the Steam Dump System is CLEAN.**
- **ENSURE 1-ALB-6D, Window 1.10, AVE TAVE-TREF DEV procedure book is CLEAN.**

EXAMINER:

PROVIDE the examinee with a copy of:

- **When ALM book referenced, provide 1-ALB-6D, Window 1.10 – AVE TAVE-TREF DEV (Procedure 1)**
- **When requested, provide ABN-709, Steam Line Pressure, Steam Header Pressure, Turbine 1st Stage Pressure and Feed Header Pressure Instrument Malfunction, Section 4.0, Turbine Impulse Pressure Instrument Malfunction (Procedure 2).**
- **When/If requested, provide ABN-709, Steam Line Pressure, Steam Header Pressure, Turbine 1st Stage Pressure and Feed Header Pressure Instrument Malfunction, Attachment 7 Transferring Steam Dumps (Procedure 3) (may use PLR 2009-0078-S, Transferring the Steam Dump System to the Steam Pressure Mode Job Aid vice the ABN Attachment)**

√ - Check Mark Denotes Critical Step

START TIME:	

Simulator Operator:	**INSERT malfunction RX09A, Main Turbine 1st Stage Pressure Transmitter failure [PT-505A] to 0% (Key 1).**
Perform Step: 1	RESPOND to Annunciator alarm.
Standard:	ACKNOWLEDGED and RESPONDED to Annunciator alarm 1-ALB-6D, Window 1.10 – AVE TAVE-TREF DEV.
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**The following steps are from 1-ALB-6D, Window 1.10 – AVE TAVE-TREF DEV. These steps will most likely be performed as diagnostics by the operator and not methodically pursued with the ALM.**
Perform Step: 2 1	STOP all secondary system power changes and ALLOW the primary and secondary to stabilize, if possible.
Standard:	DETERMINED NO secondary system power changes are in progress.
Comment:	**SAT ☐ UNSAT ☐ N/A ☐**

Perform Step: 3 2 & all bullets	VERIFY RCS temperature is > 551°F: • 1-TI-412, RC LOOP 1 TAVE CHAN I • 1-TI-422, RC LOOP 2 TAVE CHAN II • 1-TI-432, RC LOOP 3 TAVE CHAN III • 1-TI-442, RC LOOP 4 TAVE CHAN IV
Standard:	DETERMINED RCS temperature is > 551°F by OBSERVING: • 1-TI-412, RC LOOP 1 TAVE CHAN I > 551°F • 1-TI-422, RC LOOP 2 TAVE CHAN II > 551°F • 1-TI-432, RC LOOP 3 TAVE CHAN III > 551°F • 1-TI-442, RC LOOP 4 TAVE CHAN IV > 551°F
Comment:	**SAT ☐ UNSAT ☐ N/A ☐**

Perform Step: 4 3 & 3.A	MONITOR turbine impulse chamber pressure. • 1-PI-505, TURB IMP PRESS CHAN I • 1-PI-506, TURB IMP PRESS CHAN II If pressure indicates > 3% difference between channels, REFER to ABN-709.
Standard:	DETERMINED Turbine Impulse Chamber Pressure indicates > 3% difference between channels and REFERRED to ABN-709.
<u>Examiner Cue:</u>	**The Unit Supervisor directs entry into ABN-709.**
<u>Examiner Note:</u>	**The candidate should place Control Rods in MANUAL prior to notifying the Unit Supervisor that a Turbine Impulse Pressure Channel has failed.**
Comment:	**SAT ☐ UNSAT ☐ N/A ☐**

<u>Examiner Note:</u>	**The following steps are from ABN-709, Section 4.0.**
<u>Examiner Note:</u>	**When requested, PROVIDE the examinee with a copy of ABN-709.**
Perform Step: 5√ 4.3.1	PLACE 1/1-RBSS, CONTROL ROD BANK SELECT Switch in – MANUAL.
Standard:	PLACED 1/1-RBSS, CONTROL ROD BANK SELECT Switch in MANUAL and VERIFIED rod motion is stopped.
Comment:	**SAT ☐ UNSAT ☐**

<u>NOTE</u>: The following step will prevent automatic steam dump actuation on an actual load rejection, if RNO step is applied.	
Perform Step: 6 4.3.2, 4.3.2.a, & 4.3.2.b	VERIFY Steam Dumps - CLOSED WITH NO OPEN DEMAND. • 1-UI-500, STM DMP DEMAND, indicating 0% DEMAND • STM DMP VLV ZL lights indicating – CLOSED
Standard:	DETERMINED Steam Dumps CLOSED via STM DMP TRIP GRP 1 and GRP 2 green lights on all 12 Steam Dump Valves, however, OBSERVED 1-UI-500, STM DMP DEMAND indicating 100% DEMAND.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 7√ 4.3.2 RNO	<u>IF</u> steam dump operation <u>NOT</u> required, <u>THEN</u> PLACE at least one steam dump interlock select switch – OFF: • 43/1-SDA, STM DMP INTLK SELECT • 43/1-SDB, STM DMP INTLK SELECT
Standard:	PERFORMED the following: • PLACED 43/1-SDA, STM DMP INTLK SELECT in OFF (**critical**). **<u>and/or</u>** • PLACED 43/1-SDB, STM DMP INTLK SELECT in OFF (**critical**).
Comment:	**SAT ☐ UNSAT ☐**

CAUTION: A briefing should be conducted to evaluate steam dump response and contingency actions should a subsequent runback or trip occur. Reference Section 4.2.

NOTE:
- If transferring dumps to steam pressure mode, steam demand will be erroneously high if PT-505 is failed low.
- The following step ensures steam dumps available for subsequent runbacks or trips.
- Attachment 8 is available to aid in brief (L)

<u>Examiner Note:</u>	**ABN-709, Attachment 7 or identical steps located in Job Aid PLR-2009-0078-S may be referenced.**
Perform Step: 8 4.3.3	RESTORE steam dump availability by PLACING Steam Dumps in STM PRESS Mode per Attachment 7.
Standard:	REFERRED to Attachment 7, Transferring Steam Dumps **<u>or</u>** Job Aid PLR-2009-0078-S.
Comment:	**SAT ☐ UNSAT ☐**

<u>Examiner Note:</u>	**The following steps are from ABN-709, Attachment 7.**
Perform Step: 9 1	ENSURE 1-PK-507, STM DMP PRESS CTRL is in MANUAL.
Standard:	VERIFIED 1-PK-507, STM DMP PRESS CTRL in MANUAL and OBSERVED amber MANUAL light LIT.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 10 2 & both bullets	PERFORM one of the following: • MATCH 1-PK-507, STM DMP PRESS CTRL demand to 1-UI-500, STM DMP DEMAND if <u>NO control input channel is failed</u>. <u>OR</u> • MATCH 1-PK-507, STM DMP PRESS CTRL demand to current steam dump valve position
Standard:	DETERMINED 1-PK-507, STM DMP PRESS CTRL is MATCHED to current steam dump valve position.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 11 3	VERIFY 1-PCIP, 1.4 – CNDSR AVAIL STM DMP ARMED C-9 is ON.
Standard:	OBSERVED 1-PCIP, Window 1.4 – CNDSR AVAIL STM DMP ARMED C-9 annunciator LIT.
Comment:	**SAT ☐ UNSAT ☐**

<u>NOTE</u>: STM DMP VLV lights provide indication of proper system response during subsequent steps.

Perform Step: 12√ 4	PLACE 43/1-SD, STM DMP MODE SELECT in STM PRESS.
Standard:	PLACED 43/1-SD, STM DMP MODE SELECT in STM PRESS position.
Comment:	**SAT ☐ UNSAT ☐**

<u>**Examiner Note:**</u>	**If both Steam Dump Select Interlock Switches were placed in OFF at Perform Step 7, then <u>both</u> switches must be returned to ON.**
Perform Step: 13√ 5	ENSURE BOTH STM DMP INTLK SELECT switches are ON.
Standard:	PERFORMED the following: • PLACED 43/1-SDA, STM DMP INTLK SELECT in ON (**critical**). <u>**and/or**</u> • PLACED 43/1-SDB, STM DMP INTLK SELECT in ON (**critical**).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 14 6 & 6.A	<u>IF DESIRED</u> to control steam dumps in auto, <u>THEN</u> PERFORM the following: • VERIFY 1-PI-507, MS HDR PRESS indicates current MSL pressure.
Standard:	DETERMINED 1-PI-507, MS HDR PRESS at approximately 980 psig and appropriate for 100% power.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 15
6, 6.B & bullets
	<u>IF DESIRED</u> to control steam dumps in auto, <u>THEN</u> PERFORM the following:
	• ENSURE 1-PK-507, STM DMP PRESS CTRL set to:
	  • control at 1092 psig for “no-load” conditions (Pot setting 6.86), <u>OR</u>
	  • control < 1092 psig for MSL pressure < “no load” (Set Pot as desired)

Standard:	VERIFIED potentiometer on 1-PK-507, STM DMP PRESS CTRL set to 6.86.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 16√ 6 & 6.C	<u>IF DESIRED</u> to control steam dumps in auto, <u>THEN</u> PERFORM the following: • PLACE 1-PK-507, STM DMP PRESS CTRL in AUTO.
Standard:	PERFORMED the following: • DEPRESSED white pushbutton on 1-PK-507, STM DMP PRESS CTRL (**critical**). • OBSERVED white AUTO light LIT (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**Examinee should refer back to ABN-709, Step 4.3.4.**
Perform Step: 17√ 4.3.4	TRANSFER 1-PS-505Z, TURB IMP PRESS CHAN SELECT to operable channel.
Standard:	PERFORMED the following: • TRANSFERRED 1-PS-505Z, TURB IMP PRESS CHAN SELECT to Channel PS-506 (**critical**). • ACKNOWLEDGED alarm 1-ALB-6D, Window 2.9 – TURB IMP PRESS CHAN OUT OF SERV (**NOT critical**).
Terminating Cue:	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **Unit 1 is in MODE 1 at 100% power.**
- **You are the Reactor Operator.**

Initiating Cue: **The Unit Supervisor directs you to PERFORM the following:**

- **RESPOND to any alarms.**

COMANCHE PEAK STEAM ELECTRIC STATION

UNIT 1

ALARM PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____________ / ________ LATEST PCN/EFFECTIVE DATE 22 / 05/20/15 1200

QUALITY RELATED

ALARM PROCEDURE
1-ALB-6D

PROCEDURE NO. ALM-0064A
REVISION NO. 6

EFFECTIVE DATE: 7/27/99

MAJOR REVISION
CHANGES NOT INDICATED

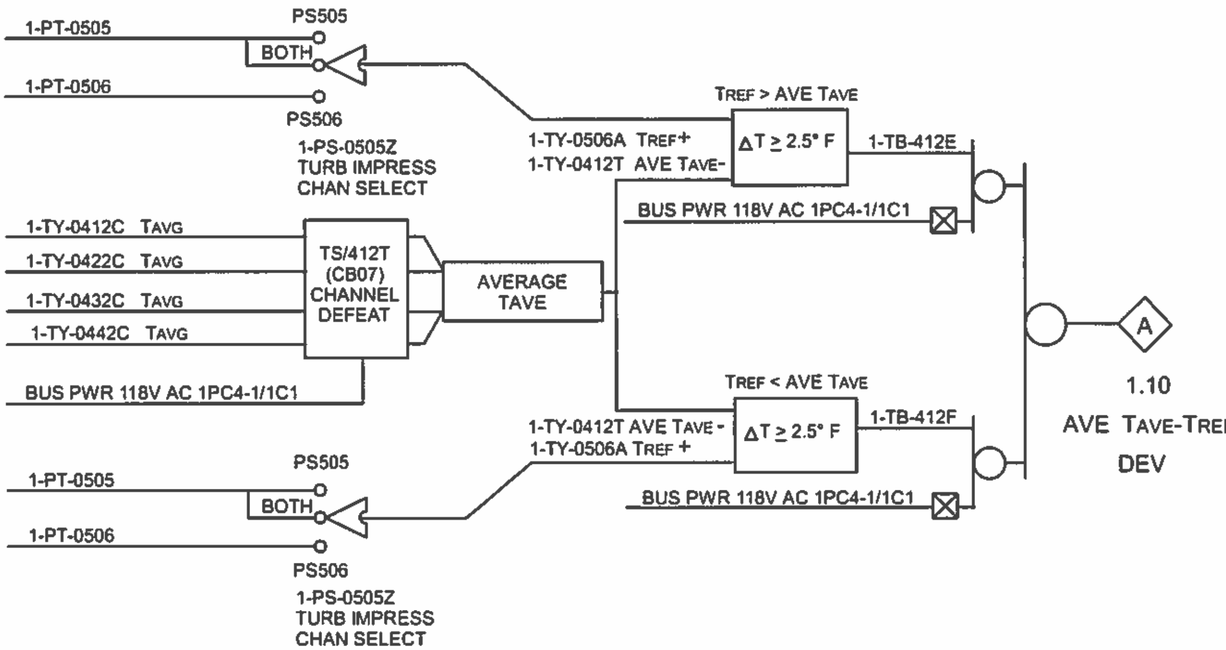
PREPARED BY (Print): Bart Smith Ext: 8837

TECHNICAL REVIEW BY (Print): Bill Gross Ext: 5799

APPROVED BY: D. Goodwin for D. Moore Date: 6/24/99
OPERATIONS MANAGER

ANNUNCIATOR NO.: 1.10

LOGIC:



PLANT COMPUTER:

T5082A RCS AVERAGE TAVE-TREF DEV
T0499A RCS AVERAGE TAVE
T0496A RCS TREF

LOCAL INSTRUMENTS:

None

REFERENCES:

8760D65 Sh.24
8810D38 Sh.40,41
8810D36 Sh.40
TDM-301A

ANNUNCIATOR NOM./NO.: **AVE TAVE - TREF DEV** **1.10**

PROBABLE CAUSE:

Instrument malfunction
Excessive turbine loading/unloading rate
Shutdown or startup operations
Excessive dilution/boration

> NOTE: On a rapid shutdown this alarm can be expected. Stop all secondary load changes UNLESS a rapid down power is in progress.

AUTOMATIC ACTIONS: None

OPERATOR ACTIONS:

1. Stop all secondary system power changes and allow the primary and secondary to stabilize, if possible.

2. Verify RCS temperature is >551°F:
   - 1-TI-412, RC LOOP 1 TAVE CHAN I
   - 1-TI-432, RC LOOP 3 TAVE CHAN III
   - 1-TI-422, RC LOOP 2 TAVE CHAN II
   - 1-TI-442, RC LOOP 4 TAVE CHAN IV

   A. If any operating loop TAVE channel is <551°F, refer to TS 3.4.2.
   B. Reduce turbine load per IPO-003A to maintain temperature >551°F.

3. Monitor turbine impulse chamber pressure.
   - 1-PI-505, TURB IMP PRESS CHAN I
   - 1-PI-506, TURB IMP PRESS CHAN II

   A. If pressure indicates >3% difference between channels, refer to ABN-709.

4. Monitor the TC channels.
   - 1-TI-411A, CL 1 TEMP (NR) CHAN I
   - 1-TI-421A, CL 2 TEMP (NR) CHAN II
   - 1-TI-431A, CL 3 TEMP (NR) CHAN III
   - 1-TI-441A, CL 4 TEMP (NR) CHAN IV

   A. If an instrument malfunction is indicated, refer to ABN-704.

5. Monitor N16 power.
   - 1-JI-411A RC LOOP 1 N16 PWR CHAN I
   - 1-JI-412A RC LOOP 2 N16 PWR CHAN II
   - 1-JI-431A RC LOOP 3 N16 PWR CHAN III
   - 1-JI-441A RC LOOP 4 N16 PWR CHAN IV

   A. If one channel is indicating >6% difference between the remaining operable channels, refer to ABN-704.

CONTINUED...

INTENTIONALLY LEFT BLANK

ANNUNCIATOR NOM./NO.: **AVE TAVE - TREF DEV** **1.10**

OPERATOR ACTIONS: (Continued)

6. Restore TAVE to within 1°F of TREF using the following methods:
   - Borate or dilute per SOP-104A.
   - Manually adjust rods 1/1-FLRM, CONTROL ROD MOTION CTRL.
   - Raise or lower turbine load per IPO-003A.

7. For unexplained dilution, refer to ABN-105.

8. Refer to TS 3.1.1, 3.4.1 and 3.3.1, Table 3.3.1-1 Function 6.

9. Correct the condition or initiate a work request per STA-606.

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1 AND 2

ABNORMAL CONDITIONS PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ______ / ______ LATEST PCN/EFFECTIVE DATE 1 / 1/28/16 1200

QUALITY RELATED

STEAM LINE PRESSURE, STEAM HEADER PRESSURE,
TURBINE 1st-STAGE PRESSURE AND FEED HEADER PRESSURE
INSTRUMENT MALFUNCTION

PROCEDURE NO. ABN-709

REVISION NO. 9

EFFECTIVE DATE: 7/23/14 1200

PREPARED BY (Print): LES MELLER EXT: 6009

TECHNICAL REVIEW BY (Print) J.D. STONE EXT: 0564

APPROVED BY: B. ST.LOUIS FOR M.R. SMITH DATE: 7/15/14
DIRECTOR, OPERATIONS

1.0 APPLICABILITY

This procedure provides the steps necessary to recover from a steam line pressure, steam header pressure, or turbine first-stage pressure instrumentation malfunction and is applicable while operating in MODES 1, 2 or 3.

This procedure is common to both units. The specific unit designator (1 or 2) is represented within these instructions by the symbol "u". The appropriate unit digit may be substituted for this symbol to obtain the unit specific equipment number. (Example u-FK-510 represents 1-FK-510 for Unit 1 and 2-FK-510 for Unit 2).

- Section 2.0 - Steam Line Pressure Instrument Malfunction
- Section 3.0 - Steam Header Pressure Instrument Malfunction
- Section 4.0 - Turbine Impulse Pressure Instrument Malfunction
- Section 5.0 - Feed Header Pressure Instrument Malfunction

4.0 TURBINE IMPULSE PRESSURE INSTRUMENT MALFUNCTION

4.1 Symptoms

a. Annunciator Alarms

- AVE Tave-Tref DEV (6D-1.10)
- Tref - AUCT LO Tave MISMATCH (6D-3.13)

b. Plant Indications

- Turbine impulse pressure channels not indicating the same.

  1) u-PI-505, TURB IMP PRESS CHAN I

  2) u-PI-506, TURB IMP PRESS CHAN II

4.2 Automatic Actions

> NOTE: TURB IMP PRESS CHAN SELECT u-PS-505Z should normally be in the "BOTH" position and input for control rod response will be from PT-505. With this switch in the PS-506 position, input for control rod response will be from PT-506.

a. Pressure Transmitter u-PT-505 (normally selected for Tref)

- u-PT-505 failing high will cause control rods to withdraw if in automatic.
- u-PT-505 failing low will cause control rods to insert if in automatic, open steam dumps if an arming signal is present and disable AMSAC actuation (PCIP 1.3, AMSAC BLK TURB <40% PWR C-20, LIT).

b. Pressure Transmitter u-PT-506

- u-PT-506 failing high will prevent steam dump actuation on an actual loss of load .
- u-PT-506 failing low will arm the steam dumps (the signal seals in) and disable AMSAC actuation (PCIP 1.3, AMSAC BLK TURB <40% PWR C-20, LIT).

4.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 1 PLACE 1/u-RBSS, CONTROL ROD BANK SELECT Switch in - MANUAL	

NOTE: The following step will prevent automatic steam dump actuation on an actual load rejection, if RNO step is applied.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
2 VERIFY Steam Dumps - CLOSED WITH NO OPEN DEMAND	IF steam dump operation NOT required, THEN PLACE at least one steam dump interlock select switch - OFF:
☐ a. u-UI-500, STM DMP DEMAND, indicating 0% DEMAND.	• 43/u-SDA, STM DMP INTLK SELECT
☐ b. STM DMP VLV ZL lights indicating - CLOSED.	• 43/u-SDB, STM DMP INTLK SELECT

CAUTION: A briefing should be conducted to evaluate steam dump response and contingency actions should a subsequent runback or trip occur. Reference Section 4.2.

NOTE:
- If transferring dumps to steam pressure mode, steam demand will be erroneously high if PT-505 is failed low.
- The following step ensures steam dumps available for subsequent runbacks or trips.
- Attachment 8 is available to aid in brief (L)

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
3 RESTORE steam dump availability by placing Steam Dumps in STM PRESS Mode per Attachment 7.	
☐ 4 TRANSFER u-PS-505Z, TURB IMP PRESS CHAN SELECT to operable channel	
☐ 5 ENSURE Tave within 1°F of Tref.	

4.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 6 RETURN 1/u-RBSS, CONTROL ROD BANK SELECT Switch to AUTO, if desired.	
☐ 7 CHECK Reactor Plant in - MODE 1	IF Reactor Plant is in MODE 2, THEN DO NOT attempt to enter MODE 1 until failed channel is repaired.
☐ 8 CHECK Turbine Power - GREATER THAN 10% POWER.	ENSURE affected channel bistable listed on Attachment 5 - RESET (normal).

NOTE: The following step will prevent the automatic block of several reactor trips when Reactor power is below 10% power.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 9 Within 1 hour, VERIFY PCIP window 4.6, TURB ≤10% PWR P-13 - IN PROPER STATE for existing plant conditions. (TS Table 3.3.1-1, item 18.f)	PERFORM the following: a. Within 1 hour, HAVE an I&C Technician place bistable test switches for failed channel in CLOSE utilizing Attachments 1 and 3. b. VERIFY appropriate alarms AND trip status lights ON per Attachment 5 AND NOTE this verification in Unit Log. IF I&C Technician NOT available, THEN a Reactor Operator may perform this step with Shift Manager/Unit Supervisor concurrence.
☐ 10 VERIFY PCIP window 1.3, AMSAC BLK TURB <40% PWR C-20 - IN PROPER STATE for actual turbine power.	IF AMSAC actuation blocked AND turbine power >40%, THEN ENSURE Automatic Actions of ALB-9B 3.7, AMSAC ACT TURB TRIP as necessary.
☐ 11 INITIATE a Condition Report per STA-421, as applicable.	

END OF SECTION

ATTACHMENT 7
PAGE 1 OF 1

TRANSFERRING STEAM DUMPS

[L] TRANSFERRING THE STEAM DUMP SYSTEM TO THE STEAM PRESSURE MODE

☐ 1. ENSURE u-PK-507, STM DMP PRESS CTRL is in MANUAL.

2. PERFORM one of the following:

- ☐ MATCH u-PK-507, STM DUMP PRESS CTRL to u-UI-500, STM DMP DEMAND if NO control input channel is failed.

  OR

- ☐ MATCH u-PK-507, STM DUMP PRESS CTRL demand to current steam dump valve position.

☐ 3. VERIFY u-PCIP, 1.4, CNDSR AVAIL STM DMP ARMED C-9 is ON.

NOTE:	STM DMP VLV lights provide indication of proper system response during subsequent steps.

☐ 4. PLACE 43/u-SD, STM DMP MODE SELECT in STM PRESS.

☐ 5. ENSURE BOTH STM DMP INTLK SELECT switches are ON.

6. IF DESIRED to control Steam Dumps in auto, THEN PERFORM the following:

☐ A. VERIFY u-PI-507, MS HDR PRESS indicates current MSL pressure.

B. ENSURE u-PK-507, STM DMP PRESS CTRL set to:

- ☐ control at 1092 psig for "no load" conditions (Pot setting 6.86),

  OR

- ☐ control < 1092 psig for MSL pressure < "no load" (Set Pot as desired)

☐ C. PLACE u-PK-507, STM DMP PRESS CTRL in AUTO.

TRANSFERRING THE STEAM DUMP SYSTEM TO THE TAVG MODE

☐ 1. VERIFY u-PCIP, 3.4, TURB LOAD REJ STM DMP ARMED C-7 is OFF.

☐ 2. ENSURE u-PK-507, STM DMP PRESS CTRL is in MANUAL and 0% demand.

☐ 3. PLACE 43/u-SD, STM DMP MODE SELECT to RESET, THEN to TAVE.

☐ 4. ENSURE u-PK-507, STM DMP PRESS CTRL set per TDM-501A/B.

Facility: CPNPP JPM # NRC S-8 Task # RO4406C K/A # 068 AK3.12 4.1 / 4.5 SF-8

Title: Respond to a Fire in the Control Room

Examinee (Print): ______________________________

Testing Method:

Simulated Performance:	______	Classroom:	______
Actual Performance:	X	Simulator:	X
Alternate Path:	______	Plant:	______
Time Critical:	______		

Initial Conditions: Given the following conditions:

- A fire has started in the Control Room.

Initiating Cue: The Shift Manager directs you to PERFORM the following:

- INITIATE actions for a Control Room Fire per ABN-803A, Respond to a Fire in the Control Room or Cable Spreading Room, Attachment 1, Reactor Operator Actions to Achieve Hot Shutdown.

Task Standard: UTILIZED ABN-803A, Attachment 1, manually TRIPPED Reactor and Turbine, ISOLATED Main Steam Lines, ISOLATED Letdown, STOPPED Reactor Coolant Pumps, SECURED Charging flow, DISABLED Residual Heat Removal (RHR) Pumps, and ISOLATED suction to the RHR Pumps from the Refueling Water Storage Tank.

Ref. Materials: ABN-803A, Response to a Fire in the Control Room or Cable Spreading Room, Rev. 13.

Validation Time: 10 minutes Completion Time: ________ minutes

Comments:

Result: SAT ☐ UNSAT ☐

Examiner (Print / Sign): ____ Date: _______________

SIMULATOR SETUP

SIMULATOR OPERATOR:

INITIALIZE to IC-18 or any at power Initial Condition and PERFORM the following:

- **VERIFY Charging Pump suction is aligned to the VCT.**
- **ENSURE 1/1-8149A, LTDN ORIFICE ISOL VLV AND 1/1-8149B, LTDN ORIFICE ISOL VLV in service.**

EXAMINER:

PROVIDE the applicant with a copy of:

- **ABN-803A, Response to a Fire in the Control Room or Cable Spreading Room, Attachment 1, Reactor Operator Actions to Achieve Hot Shutdown (Procedure).**

√ - Check Mark Denotes Critical Step

START TIME:	

Examiner Note:	**The following steps are from ABN-803A, Attachment 1.**
NOTE: Steps should be performed as rapidly as possible based on operator knowledge to ensure prompt transition to RSP.	
Perform Step: 1√ a & 1st bullet	Manually TRIP Reactor and VERIFY the following: • Reactor trip and bypass breakers – OPEN
Standard:	PERFORMED the following: • PLACED 1/1-RTC, RX TRIP BKR switch in TRIP (**critical**). • OBSERVED 1/1-RTBAL, RX TRIP BKR green light LIT. (**NOT critical**). • OBSERVED 1/1-RTBBL, RX TRIP BKR green light LIT. (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 2 a & 2nd bullet	Manually TRIP Reactor and VERIFY the following: • Neutron flux – DECREASING
Standard:	OBSERVED 1-NI-35B, IR CURRENT CHAN I and 1-NI-36B, IR CURRENT CHAN II lowering.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 3 a & 3rd bullet	Manually TRIP Reactor and VERIFY the following: • All DRPI RB lights – ON
Standard:	OBSERVED all Control Rods INSERTED on CTRL ROD POSN bezel.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 4 b	ENSURE Turbine – TRIPPED
Standard:	DETERMINED HP Turbine Stop Valves CLOSED and OBSERVED; • 1-ZL2429A, HPT STOP VLV 1 green light LIT. • 1-ZL2431A, HPT STOP VLV 2 green light LIT. • 1-ZL2430A, HPT STOP VLV 3 green light LIT. • 1-ZL2428A, HPT STOP VLV 4 green light LIT.
Comment:	**SAT ☐ UNSAT ☐**

NOTE: The following actions should be performed prior to evacuating Control Room. Steps will be taken after Control Room evacuation to locally ensure required actions have been completed except for step e. which does not require local verification.

Perform Step: 5√ c	ENSURE 1-HS-2452-F, AFWPT TRIP – TRIPPED
Standard:	PERFORMED the following: • DEPRESSED 1-HS-2452-F, AFWPT TRIP pushbutton (**critical**). • OBSERVED 1-HS-2452G, AFWPT TRIP & THROTTLE VLV green VLV light LIT (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Examiner Note:	**Operation of EITHER 1-HS-2337A or 1-HS-2337B will isolate the Main Steam Lines and satisfy BOTH Critical JPM Steps 6 & 7.**
Perform Step: 6√ d & 1st bullet	ISOLATE Main Steam Lines. • 1-HS-2337A, MSL ISOL MAN ACT/RESET
Standard:	PERFORMED the following: • PLACED 1-HS-2337A, MSL ISOL MAN ACT/RESET in ACT position (**critical**). • OBSERVED 1-HS-2333A (2334A/2335A/2336A), MSIV 1(2/3/4), green CLOSE lights LIT (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐ N/A ☐**

Perform Step: 7√ d & 2nd bullet	ISOLATE Main Steam Lines. • 1-HS-2337B, MSL ISOL MAN ACT/RESET
Standard:	PERFORMED the following: • PLACED 1-HS-2337B, MSL ISOL MAN ACT/RESET in ACT position (**critical**). • OBSERVED 1-HS-2333A(2334A/2335A/2336A), MSIV 1(2/3/4), green CLOSE lights LIT (**NOT critical**).
Comment:	**SAT** ☐ **UNSAT** ☐ **N/A** ☐

Perform Step: 8 e	ENSURE 1/1-8202A <u>AND</u> 1/1-8202B, VENT VLV – CLOSED.
Standard:	DETERMINED 1/1-8202A <u>AND</u> 1/1-8202B, VENT VLV in CLOSE and OBSERVED green CLOSE lights LIT.
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 9√ f & 1st bullet	CLOSE the following valves: • 1/1-8149A, LTDN ORIFICE ISOL VLV (45 GPM)
Standard:	PERFORMED the following: • PLACED 1/1-8149A, LTDN ORIFICE ISOL VLV in CLOSE (**critical**). • OBSERVED green CLOSE light LIT (**NOT critical**).
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 10√ f & 2nd bullet	CLOSE the following valves: • 1/1-8149B, LTDN ORIFICE ISOL VLV (75 GPM)
Standard:	PERFORMED the following: • PLACED 1/1-8149B, LTDN ORIFICE ISOL VLV in CLOSE (**critical**). • OBSERVED green CLOSE light LIT (**NOT critical**).
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 11 f & 3rd bullet	CLOSE the following valves: • 1/1-8149C, LTDN ORIFICE ISOL VLV (75 GPM)
Standard:	DETERMINED 1/1-8149C, LTDN ORIFICE ISOL VLV in CLOSE and OBSERVED green CLOSE light LIT.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 12 f & 4th bullet	CLOSE the following valves: • 1/1-8153, XS LTDN ISOL VLV
Standard:	DETERMINED 1/1-8153, XS LTDN ISOL VLV in CLOSE and OBSERVED green CLOSE light LIT.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 13 f & 5th bullet	CLOSE the following valves: • 1/1-8154, XS LTDN ISOL VLV
Standard:	DETERMINED 1/1-8154, XS LTDN ISOL VLV in CLOSE and OBSERVED green CLOSE light LIT.
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 14√ g & 1st bullet	PERFORM the following: • OPEN 1/1-LCV-112E, RWST TO CHRG PMP SUCT VLV.
Standard:	PERFORMED the following: • PLACED 1/1-LCV-112E, RWST TO CHRG PMP SUCT VLV in OPEN (**critical**). • OBSERVED red OPEN light LIT (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 15√ g & 2nd bullet	PERFORM the following: • OPEN 1/1-LCV-112D, RWST TO CHRG PMP SUCT VLV.
Standard:	PERFORMED the following: • PLACED 1/1-LCV-112D, RWST TO CHRG PMP SUCT VLV in OPEN (**critical**). • OBSERVED red OPEN light LIT (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 16√ g & 2nd bullet	PERFORM the following: • Place 1/1-APCH1, CCP 1 in PULL-OUT.
Standard:	PERFORMED the following: • PLACED 1/1-APCH1, CCP 1 in PULL-OUT (**critical**). • OBSERVED green TRIP light DARK and red FAN light LIT. (**NOT critical**).
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 17√ h & 1st bullet	STOP Reactor Coolant Pumps. • 1/1-PCPX1, RCP 1
Standard:	PERFORMED the following: • PLACED 1/1-PCPX1, RCP 1 in STOP (**critical**). • OBSERVED green STOP light LIT (**NOT critical**).
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 18√ h & 2nd bullet	STOP Reactor Coolant Pumps. • 1/1-PCPX2, RCP 2
Standard:	PERFORMED the following: • PLACED 1/1-PCPX2, RCP 2 in STOP (**critical**). • OBSERVED green STOP light LIT (**NOT critical**).
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 19√ h & 3rd bullet	STOP Reactor Coolant Pumps. • 1/1-PCPX3, RCP 3
Standard:	PERFORMED the following: • PLACED 1/1-PCPX3, RCP 3 in STOP (**critical**). • OBSERVED green STOP light LIT (**NOT critical**).
Comment:	**SAT** ☐ **UNSAT** ☐

Perform Step: 20√ h & 4th bullet	STOP Reactor Coolant Pumps. • 1/1-PCPX4, RCP 4
Standard:	PERFORMED the following: • PLACED 1/1-PCPX4, RCP 4 in STOP (**critical**). • OBSERVED green STOP light LIT (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 21√ i & 1st bullet	PLACE <u>BOTH</u> RHR pumps – PULL-OUT. • 1/1-APRH1, RHRP 1
Standard:	PERFORMED the following: • PLACED 1/1-APRH1, RHRP 1 in PULL-OUT (**critical**). • OBSERVED green PUMP light DARK (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 22√ i & 2nd bullet	PLACE <u>BOTH</u> RHR pumps – PULL-OUT. • 1/1-APRH2, RHRP 2
Standard:	PERFORMED the following: • PLACED 1/1-APRH2, RHRP 2 in PULL-OUT (**critical**). • OBSERVED green PUMP light DARK (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 23√ j & 1st bullet	CLOSE following valves: • 1/1-8812A, RWST TO RHRP 1 SUCT VLV
Standard:	PERFORMED the following: • PLACED 1/1-8812A, RWST TO RHRP 1 SUCT VLV in CLOSE (**critical**). • OBSERVED green CLOSE light LIT (**NOT critical**).
Comment:	**SAT ☐ UNSAT ☐**

Perform Step: 24√ j & 2nd bullet	CLOSE following valves • 1/1-8812B, RWST TO RHRP 2 SUCT VLV
Standard:	PERFORMED the following: • PLACED 1/1-8812B, RWST TO RHRP 2 SUCT VLV in CLOSE (**critical**). • OBSERVED green CLOSE light LIT (**NOT critical**).
<u>**Terminating Cue:**</u>	**This JPM is complete.**
Comment:	**SAT ☐ UNSAT ☐**

STOP TIME:	

Initial Conditions: **Given the following conditions:**

- **A fire has started in the Control Room.**

Initiating Cue: **The Shift Manager directs you to PERFORM the following:**

- **INITIATE actions for a Control Room Fire per ABN-803A, Respond to a Fire in the Control Room or Cable Spreading Room, Attachment 1, Reactor Operator Actions to Achieve Hot Shutdown.**

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

ABNORMAL CONDITIONS PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ______ / ______ LATEST PCN/EFFECTIVE DATE 3 / 9/14/16 1200

QUALITY RELATED

RESPONSE TO A FIRE IN THE CONTROL ROOM OR CABLE SPREADING ROOM

PROCEDURE NO. ABN-803A

REVISION NO. 13

EFFECTIVE DATE: 8-27-15 1200

PREPARED BY (Print): J.D. STONE Ext: 0564

TECHNICAL REVIEW BY (Print): DILLON RICHEY Ext: 6769

APPROVED BY: Joe Ricks for D. McGaughey Date: 8/24/15
DIRECTOR, OPERATIONS

1.0 Applicability

This procedure describes the actions to be taken for a loss of habitability in the Control Room. This procedure applies if habitability is lost due to a fire within the Control Room or Cable Spreading Room. This procedure applies to Unit 1 operation only.

Management review will be necessary to ensure configuration tracking and restoration.

This procedure is applicable for initiating events occurring in Modes 1 and 2. This procedure assumes RHR is not operating and SI is operable. Using this procedure when not in one of these modes requires a step by step evaluation to determine if the required action is still applicable to current plant conditions.

This procedure should NOT be used for testing purposes. Transferring equipment from Control Room control to Remote Shutdown Panel control defeats all automatic Engineered Safety Features (ESF) actuations associated with the equipment. This procedure transfers many ESF components from both trains. This may place the unit into Technical Specification 3.0.3 action statement.

This procedure should be entered at the first indication of a potential fire, based on an assessment by the Shift Manager, in the common areas of the Control room (includes TSC and Control Room HVAC area) or either unit's Cable Spreading Room.

- Fire affected ECB Fire Areas EM, EN and EO (Section 2.0)

  Fire Area EM, EN and EO consists of following rooms/areas:

Elevation	Room NO.	Description
807	X-133	Unit 1 Cable Spread Room
807	X-134	Unit 2 Cable Spread Room
830	X-135	Unit 1 and Unit 2 Control Room and Protection Racks
	X-136	Unit 2 Computer Room
	X-137	Shift Manager Office
	X-139	CPC
	X-141	Restroom
	X-142	Locker Room
	X-144	Kitchen
	X-146	Chart Room/Clerk Office
	X-147	Unit 1 Computer Room
841	X-148	Hallway
	X-148A	Operations Office
	X-148B	Operations Briefing Room
	X-149A	Technical Support Center

ATTACHMENT 1
PAGE 1 OF 6

REACTOR OPERATOR ACTIONS TO ACHIEVE HOT SHUTDOWN

NOTE: Steps should be performed as rapidly as possible based on operator knowledge to ensure prompt transition to RSP.

[C] ☐ a. Manually TRIP Reactor and VERIFY the following:

- Reactor trip and bypass breakers - **OPEN**
- Neutron flux - **DECREASING**
- All DRPI RB lights - **ON**

☐ b. ENSURE Turbine - **TRIPPED**

NOTE: The following actions should be performed prior to evacuating Control Room. Steps will be taken after Control Room evacuation to locally ensure required actions have been completed except for step e. which does not require local verification.

☐ c. ENSURE 1-HS-2452-F, AFWPT TRIP - **TRIPPED**

☐ d. ISOLATE Main Steam Lines.

- 1-HS-2337A, MSL ISOL MAN ACT/RESET
- 1-HS-2337B, MSL ISOL MAN ACT/RESET

[C] ☐ e. ENSURE the following valves - **CLOSED**.

- 1/1-8202A, VENT VLV
- 1/1-8202B, VENT VLV

☐ f. **CLOSE** the following valves:

- 1/1-8149A, LTDN ORIFICE ISOL VLV (45 GPM)
- 1/1-8149B, LTDN ORIFICE ISOL VLV (75 GPM)
- 1/1-8149C, LTDN ORIFICE ISOL VLV (75 GPM)
- 1/1-8153, XS LTDN ISOL VLV
- 1/1-8154, XS LTDN ISOL VLV

REACTOR OPERATOR ACTIONS TO ACHIEVE HOT SHUTDOWN

☐ g. PERFORM the following:

- **OPEN** 1/1-LCV-112E, RWST TO CHRG SUCT VLV
- **OPEN** 1/1-LCV-112D, RWST TO CHRG SUCT VLV
- **PLACE** 1/1-APCH1, CCP 1 in **PULL-OUT**

☐ h. **STOP** Reactor Coolant Pumps.

- 1/1-PCPX1, RCP 1
- 1/1-PCPX2, RCP 2
- 1/1-PCPX3, RCP 3
- 1/1-PCPX4, RCP 4

☐ i. **PLACE** BOTH RHR pumps - **PULL-OUT**.

- 1/1-APRH1, RHRP 1
- 1/1-APRH2, RHRP 2

☐ j. **CLOSE** following valves:

- 1/1-8812A, RWST TO RHRP 1 SUCT VLV
- 1/1-8812B, RWST TO RHRP 2 SUCT VLV

☐ k. PROCEED to Remote Shutdown Panel to continue this attachment.

ATTACHMENT 1
PAGE 3 OF 6

REACTOR OPERATOR ACTIONS TO ACHIEVE HOT SHUTDOWN

NOTE: Attachment 13, ABN-803A Job Aid may be used to track actions of RRO, NEO 1 and NEO 2.

l. DEENERGIZE 1EA2 as follows:

☐ 1) TRANSFER following controls from **CR** to **HSP**:

- 43-1EG2, DG 2 BKR 1EG2 CTRL XFER
- 43-1EA2-2, BKR 1EA2-2 CTRL XFER
- 43-1EA2-1, BKR 1EA2-1 CTRL XFER

☐ 2) PLACE following handswitches in **PULL-OUT**:

A. CS-1EG2-L, DG 2 BKR 1EG2
B. CS-1EA2-2L, INCOMING BKR 1EA2-2
C. CS-1EA2-1L, INCOMING BKR 1EA2-1

☐ m. WHEN control has been transferred to RSP,
THEN
ENSURE the following:

- 1/1-455AFL, PRZR PORV - **CLOSED**
- 1/1-456FL, PRZR PORV - **CLOSED**
- 1/1-APRH1F, RHRP 1 - **OFF**
- 1/1-APCH1L, CCP 1 - **OFF**
- 1-HS-2333FL, MSIV 1 - **CLOSED**
- 1-HS-2334FL, MSIV 2 - **CLOSED**
- 1-HS-2335FL, MSIV 3 - **CLOSED**
- 1-HS-2336FL, MSIV 4 - **CLOSED**
- 1/1-8149AL, LTDN ORIFICE ISOL VLV (45 GPM) - **CLOSED**
- 1/1-8149BL, LTDN ORIFICE ISOL VLV (75 GPM) - **CLOSED**
- 1/1-8149CL, LTDN ORIFICE ISOL VLV (75 GPM) - **CLOSED**
- 1/1-LCV-0112BFL, VCT ISOL VLV 112B - **CLOSED**
- 1/1-LCV-0112DFL, RWST CHRGNG PMP VLV - **OPEN**

REACTOR OPERATOR ACTIONS TO ACHIEVE HOT SHUTDOWN

n. IF the Diesel Generator is NOT supplying power to 1EA1,
THEN
PERFORM the following:

☐ 1) ENSURE the following equipment - **OFF**:

- 1-HS-6700FL, SFTY CH WTR RECIRC PMP 05
- 1-HS-2450C, MD AFWP 1
- 1-HS-4518C, CCWP 1
- 1-HS-4250C, SSWP 1

NOTE: The Diesel Generator supply breaker should automatically close when selected to HSP with 1EA1 de-energized after DG is ready to load. The automatic closure occurs approximately 7 seconds after bus is deenergized.

☐ 2) WHEN notified by RRO that Trn A DG is running,
THEN
PERFORM the following:

A) DEENERGIZE 1EA1 by placing the following handswitches in **TRIP** (Breaker verified OPEN) THEN **PULL OUT**:

- CS-1EA1-2L,INCOMING BKR 1EA1-2
- CS-1EA1-1L,INCOMING BKR 1EA1-1

B) IF CS-1EA1-1L did NOT indicate OPEN,
THEN
INFORM RRO to perform Attachment 2 Step "m" AND "n" AND then to resume Attachment 2.

☐ 3) WHEN 1EA1 is deenergized,
THEN
ENSURE CS-1EG1-L, DG 1 BKR - **CLOSED**.

☐ 4) ENSURE proper voltage and frequency:

- V-1EA1-L, BUS 1EA1 VOLT 6600 - 7200 volts
- F-1EA1-L, BUS 1EA1 FREQ 59.5 - 60.5 Hz

ATTACHMENT 1
PAGE 5 OF 6

REACTOR OPERATOR ACTIONS TO ACHIEVE HOT SHUTDOWN

> CAUTION:
> - When manually loading diesel generator, allow adequate time between major equipment starts for voltage to stabilize (~15 seconds).
> - Do not exceed 585 AMPS on Diesel Generator. (This will limit load to less than 7.0 MW).

☐ o. IF SSW is NOT operating,
THEN
PERFORM the following:

1) **CLOSE** 1-HS-4286FL, SSWP 1 DISCH VLV. (Indicates mid position)

2) **START** 1-HS-4250C, SSWP 1.

3) **OPEN** 1-HS-4286FL, SSWP 1 DISCH VLV.

☐ p. ENSURE 1-HS-4393FL, DG 1 CLR SSW RET VLV - **OPEN**.

☐ q. ENSURE 1-HS-6700FL, SFTY CH WTR RECIRC PMP 05 - **RUNNING**.

r. MAINTAIN SG 1 and SG 2 actual levels between 84% and 92% (at 551°F, this corresponds to indicated level of 63% to 68%) as follows:

☐ 1) ENSURE 1-HS-2456FL, MD AFWP 1 RECIRC VLV - **OPEN**.

☐ 2) OPERATE 1-HS-2450C, MD AFWP 1 as necessary to control SG level.

☐ 3) WHEN NEO #2 has completed Attachment 4,
THEN
DIRECT NEO #2 in locally controlling Auxiliary Feedwater flow.

s. ALIGN charging flow path as follows:

☐ 1) ENSURE 1/1-8801AF, CCP SI ISOL VLV - **OPEN**.

☐ 2) **CLOSE** 1/1-8106FL, CHRG PMP TO RCS ISOL VLV.

☐ 3) ENSURE 1/1-8110FL, CCP 1 & 2 MINIFLOW VLV - **OPEN**.

ATTACHMENT 1
PAGE 6 OF 6

REACTOR OPERATOR ACTIONS TO ACHIEVE HOT SHUTDOWN

☐ t. VERIFY that NEO #1 is ready to control charging flow per Attachment 3 prior to starting Centrifugal Charging Pump 1-01.

NOTE:
- The CCP should be started as soon as possible if needed for inventory control. Otherwise start should be delayed until CCW established to the seal cooler to ensure recirculation cooling. If SDS activate and there are no spurious openings, charging may not be required until cooldown is started.
- Control charging through 1-8485A-RO, CCP 1-01 DISCH VLV RMT OPER to maintain Pressurizer level.
- Steps u. v. and w. can be performed in parallel.

☐ u. START 1/1-APCH1L, CCP 1.

☐ v. DIRECT NEO #1 to establish charging flow.

- 1-8485A-RO, CCP 1-01 DISCH VLV RMT OPER (AB 822 Rm X-209)

w. WHEN NEO #2 has positioned 1-HV-4572, RHR HX 1 CCW RET VLV,
THEN
ENSURE CCW system aligned as follows:

☐ 1) ENSURE 1-HS-4514FL, SFGD LOOP CCW SPLY VLV - **CLOSED**.

☐ 2) ENSURE 1-HS-4518C, CCWP 1 - **RUNNING**.

☐ x. MAINTAIN 1-LI-459B, PRZR LVL between 50% and 90%.

☐ y. RETURN to Section 2.3 Step 8 this procedure.

Facility: CPNPP 1 & 2	Scenario No.: 1 Op Test No.: June 2017 NRC
Examiners: ______ ______ ______	Operators: ______ ______ ______

Initial Conditions: 100% power MOL – RCS Boron is 771 ppm (by sample). MDAFW Pump 1-02 is out of service for an oil change.

Turnover: Maintain steady state power conditions

Critical Tasks: **CT-1 -** Ensure Control Rods inserting ≥ 48 Steps / Minute During Reactor Trip Failure Prior to Exiting FRS-0.1A, Response to Nuclear Power Generation / ATWT.

CT-2 - Identify and Isolate the Ruptured Steam Generator Prior to Commencing an Operator Induced Cooldown per EOP-3.0A, Steam Generator Tube Rupture.

Event No.	Malf. No.	Event Type*	Event Description
1	RX08A	I (RO,SRO) TS (SRO)	Pressurizer Pressure Channel (PT-455) fails high
2	CH10	C (BOP, SRO)	CRDM Vent Fan #1 trips
3	RX02G	I (BOP, SRO)	SG 1-04 Steam Flow (FI-542A) Fails Low
4	RP05A	I (RO, SRO) TS (SRO)	NR Cold Leg 1 Temp (TE-411B) fails low
5	RC03C	R (RO) C (BOP ,SRO)	Loss of B MFP
6	RC19C	M (RO,BOP,SRO)	Loss of A MFP. Reactor fails to trip. Reactor trip breakers fail to open. Bus Breaker CS-1B4-1 Fails to Open
7	SG02D	M (RO,BOP,SRO)	SG 1-04 Tube Rupture (2 tubes)
8	FW38D	C (BOP)	SG 1-04 FWIV Fails to Close

* (N)ormal, (R)eactivity, (I)nstrument, (C)omponent, (M)ajor, (TS)Technical Specifications

Actual	**Target Quantitative Attributes**
8	Total malfunctions (5-8)
3	Malfunctions after EOP entry (1-2)
5	Abnormal events (2-4)
2	Major transients (1-2)
2	EOPs entered/requiring substantive actions (1-2)
1	EOP contingencies requiring substantive actions (0-2)
2	Critical tasks (2-3)

SCENARIO 1 SUMMARY

Event 1
The first event is a failure of Pressurizer Pressure Channel PT-455 high. The crew will enter ABN-705, Pressurizer Pressure Malfunction, Section 2.0, Pressurizer Pressure Instrument Malfunction. The associated PORV will open and the operator will close the PORV, its associated Block Valve, and place 1-PK-455A, Master Pressurizer Pressure Controller in manual and control PZR pressure. The SRO will refer to Technical Specifications.

Event 2
The operating CRDM vent fan trips. The crew will refer to 1-ALB-3A, Window 1.6, CRDM SHROUD EXH TEMP HI, and ensure that at least one CRDM vent fan is in service, and manually start an alternate vent fan, per SOP-801A, Containment Ventilation System. They will use either Section 5.3.1, Control Rod Drive Mechanism Ventilation System Startup, or Section 5.3.3, Alternating Control Rod Drive Mechanism Ventilation Fans, for this evolution.

Event 3
1-FI-542A, SG 1-04 STM FLO, Selected Steam Flow transmitter fails Low. The crew will enter ABN-707, Section 2.0, Steam Flow Instrument Malfunction. The operators will take manual control of the affected FRV and master feed pump speed control. The alternate channel will be selected for control and the system will be returned back to automatic control.

Event 4
Failure of Cold Leg Loop 1 NR Temperature Transmitter (TE-411B). It will fail low (510°F). The Reactor Operator will take action per ABN-704, Tc/N-16 Instrumentation Malfunction, Section 2.0. This event requires taking manual control of rods, since the Tc failure results in a lower Tave and rods will withdraw in automatic until C-11 is reached. The SRO will refer to Technical Specifications for this malfunction.

Event 5
Event 5 is the precursor to the major event and involves a trip of the main feed pump with a turbine runback (rod control is still in manual from the previous event). Operators will take action per ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 2.0, and ramp the unit down. The second feed pump will trip 3 minutes after the first.

Event 6,7,8
After the loss of the 2nd MFP a reactor trip is warranted and an attempt will be made to manually trip the Reactor via the Normal Trip Switches and by de-energizing both buses supplying the Control Rod Drive Mechanism Motor Generators. Operators will enter FRS-0.1A, Response To Nuclear Power Generation/ATWT. Operators will be required to drive control rods inward until the reactor trip breakers are opened locally and Emergency Borate. After the reactor is shutdown a tube rupture will occur on SG 1-04. Operators will exit FRS-0.1A; perform the actions of EOP-0.0A, Reactor Trip or Safety Injection, and transition to EOP-3.0A, Steam Generator Tube Rupture. A failure of SG 1-04 FWIV to close will complicate the event.

Terminating Criteria
Scenario will be terminated when the operators have completed an RCS cooldown, and an RCS depressurization has begun, or at the Examiner’s discretion.

Risk Significance:

• Failure of risk important system prior to trip:	Pressurizer Pressure Channel Fails high Main Feed Pump B Trips
• Risk significant core damage sequence:	Main Feed Pump A Trips; ATWT
• Risk significant operator actions:	Isolation of Ruptured Steam Generator complicated by FWIV failure to close

Critical Task Determination

Critical Task	Safety Significance	Cueing	Measurable Performance Indicators	Performance Feedback
Ensure Control Rods inserting ≥ 48 Steps / Minute During Reactor Trip Failure Prior to Exiting FRS-0.1A, Response to Nuclear Power Generation / ATWT	The safeguards systems that protect the plant during accidents are designed assuming that only decay heat and pump heat are being added to the RCS.	DRPI lights indicating rods are withdrawn after both reactor trip switches have been turned, two red indicating lights lit for both reactor trip breakers after the reactor trip switches have been turned, power range detectors showing power greater than 5%. Procedurally driven from FRS-0.1A	Observance of the RO verifying control rods are inserting ≥ 48 Steps / Minute in auto and when speed slows then rods are placed in manual and driven in	DRPI indicating lights moving in the inward direction, rod speed indicator showing rod speed during the transient. After reactor trip breakers opened two green lights for the reactor trip breakers
Identify and Isolate the Ruptured Steam Generator Prior to Commencing an Operator Induced Cooldown per EOP-3.0A, Steam Generator Tube Rupture.	Take one or more actions that would prevent a challenge to plant safety. STI-214.01, TCA-1.9; FSAR 15.6.3.1.1; WCAP-16871-P, Section 6.4; DBD-ME-027. (NOT TCA due to additional failure)	Procedurally driven from EOP-3.0A, to identify and isolate a ruptured SG. Indications include MSL Radiation alarms and SG level.	The operator will not be able to close the MSIV, so all other MSIVs must be closed. The operator will ensure the FW isolation valves are closed, and reduce AFW flow to SG 1-04.	SG pressure increasing, AFW flow reduced to zero and valve position indications.

	SIMULATOR OPERATOR INSTRUCTIONS for SIMULATOR SETUP				
Initialize to IC18 and LOAD 2017 NRC Scenario 1.					
EVENT	**TYPE**	**MALF #**	**DESCRIPTION**	**DEMAND VALUE**	**INITIATING PARAMETER**
SETUP	IRF	FWR021	MDAFWP 1-02 Breaker Racked Out	f:0	K0
6	IMF	RP15E	Reactor Trip Breakers Jammed Closed	f:1	K0
	IOR	DIED1B41	Bus Breaker CS-1B4-1 Fails to Open	f:3	K0
8	IMF	FW38D	SG (1-04) FWIV Fails to Close	f:1	K0 (2)
1	IMF	RX08A	Pressurizer Pressure Channel (PT-455) fails high	f:2500	K1
2	IMF	CH10	CRDM Vent Fan #1 trips	f:1	K2
3	IMF	RX02G	SG 1-04 Steam Flow (FI-542A) fails low	f:0	K3
4	IMF	RP05A	NR Cold Leg 1 Temp (TE-411B) fails low	f:510	K4
5	IMF	FW03B	Main Feedwater Pump B trip	f:1	K5
6	IMF	FW03A	Main Feedwater Pump A trip	f:1	K5 +180
	IMF	RP15E	Reactor Fails to trip –Reactor trip breakers jammed closed	f:1	K0
	IOR	DIED1B41	Bus Breakers CS-1B4-1 Fails to open	f:3	K0
6	IRF	RPR112	Locally open Reactor Trip Breaker Train A	f:2	K10
	IRF	RPR113	Locally open Reactor Trip Breaker Train B	f:2	K10
7	IMF	SG02D	SG (1-04) Tube Rupture (2 tubes)	f:2	(1)
8	IMF	FW38D	SG (1-04) FWIV fails to close	f:1	K0 (2)
(1) {LORPRTBAL_1.Value} IMF SG02D f:2 r:60 Tube rupture will be set to actuate upon the RTB lights changing from red to green (60 second ramp)					
(2) {DIFWHS2137.Value=0} DMF FW38D Allow 1-HV-2137 SG 1-04 FWIV to close with handswitch					

Simulator Operator:	**INITIALIZE to IC18 and LOAD NRC Scenario 1.** **ENSURE all Simulator Annunciator Alarms are ACTIVE.** **ENSURE RED Danger Tag on MDAFWP 1-02 and place in PULL-OUT** **ENSURE GEM Box PLACED on 1-HS-2450A for MDAFWP 1-01** **ENSURE all Control board Tags are removed.** **ENSURE Operator Aid Tags reflect current boron conditions (771 ppm)** **ENSURE Rod Bank Update (RBU) is performed.** **ENSURE Turbine Load Rate set at 10 Mwe/min.** **ENSURE 60/90 buttons DEPRESSED on ASD** **ENSURE ASD speakers are ON at half volume.** **ENSURE Reactivity Briefing Sheet printout provided with Turnover.** **ENSURE procedures in progress are on SRO desk:** **- COPY of IPO-003A, Power Operations, Section 5.5, Operating at Constant Turbine Load.** **ENSURE Control Rods are in AUTO with Bank D at 215 steps.**

Control Room Annunciators in Alarm:

PCIP-1.1 – SR TRN A RX TRIP BLK
PCIP-1.2 – IR TRN A RX TRIP BLK
PCIP-1.4 – CNDSR AVAIL STM DMP ARMED C-9
PCIP-1.6 – RX ≥ 10% PWR P-10
PCIP-2.1 – SR TRN B RX TRIP BLK
PCIP-2.2 – IR TRN B RX TRIP BLK
PCIP-2.5 – SR RX TRIP BLK PERM P-6
PCIP-3.2 – PR TRN A LO SETPT RX TRIP BLK
PCIP-4.2 – PR TRN B LO SETPT RX TRIP BLK
1-SSII2 – Train B MDAFW is Solid Red

Operating Test :	NRC	Scenario #	1	Event #	1	Page	7	of	53
Event Description:	Pressurizer Pressure Channel (PT-455) fails high								

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, execute Event 1 (Key 1).** **- RX08A, Pressurizer Pressure Channel (PT-455) fails high.**
Indications Available: **5C-1.4 – PORV 455A/456 NOT CLOSE** **5C-3.1 – PRZR 1 OF 4 PRESS HI** **5C-4.3 – PRZR PRESS DEV HI** **PRZR variable heaters turn OFF** **Both PRZR spray valves OPEN** **PORV OPENs and then closes once pressure reduces to 2185 psig**		
	RO	RESPOND to Annunciator Alarm Procedures.
	RO	RECOGNIZE PRZR pressure channel PT-455 has failed high.
	US	DIRECT performance of ABN-705, Pressurizer Pressure Malfunction
Examiner Note:		**The following steps are from ABN-705, Pressurizer Pressure Malfunction, Section 2.0, Pressurizer Pressure Instrument Malfunction**
NOTE:		• Diamond steps denote initial action. • A PORV is not considered INOPERABLE when its actuation instrumentation is not functioning. • Power should NOT be removed from a block valve closed in accordance with this procedure section.
	◊ RO ◊	VERIFY PORV – CLOSED. [Step 2.3.1] • Place PRZR PORV, 1/1-PCV-455A to CLOSE • Place PRZR PORV BLK VLV, 1/1-8000A to CLOSE
	◊ RO ◊	PLACE 1-PK-455A, PRZR MASTER PRESS CTRL in MANUAL. [Step 2.3.2]

Operating Test :	NRC	Scenario #	1	Event #	1	Page	8	of	53
Event Description:	Pressurizer Pressure Channel (PT-455) fails high								

Time	Position	Applicant's Actions or Behavior
	◊ RO ◊	ADJUST 1-PK-455A for current RCS pressure. [Step 2.3.3] • Ensure Heaters are ON and PRZR Spray is OFF
	RO	TRANSFER 1/1-PS-455F, PRZR PRESS CTRL CHAN SELECT to an Alternate Controlling Channel. [Step 2.3.4] • PLACE 1/1-PS-455F, PRZR PRESS CTRL CHAN SELECT to the 457/456 position
	RO	PLACE 1-PK-455A, PRZR MASTER PRESS CTRL in AUTO. [Step 2.3.5]
	RO	VERIFY automatic control restoring Pressurizer pressure to 2235 psig. [Step 2.3.6]
	RO	ENSURE valid channel selected to recorder. [Step 2.3.7] • 1/1-PS-455G, 1-PR-455 PRZR PRESS SELECT selected to the 457 or 456 position.
	US/RO	IF necessary, return PORV closed in Step 1 RNO to AUTO and ENSURE it remains closed. [Step 2.3.8] • Place PRZR PORV, 1/1-PCV-455A to AUTO
NOTE: It may be necessary to leave the PORV Block Valve closed to aid in establishing a water seal. Reference ALM-0053A/B.		
	US/RO	IF necessary, OPEN block valve closed in Step 1 RNO. [Step 2.3.9] • Place PRZR PORV BLK VLV, 1/1-8000A to OPEN
	US/RO	Within one hour, VERIFY PCIP Window 2.6 – PRZR PRESS SI BLK PERM P-11 – DARK. [Step 2.3.10]
	US/RO	VERIFY other instruments on common instrument line – NORMAL. [Step 2.3.11] • Attachment 1, Instrument Loop – 1, LT-459

NOTE:
- If the failed channel temperature was reading lower than the substituted channel, then AVE Tave will increase when the channel is defeated due to another channel being substituted for the defeated signal to maintain accurate averaging.
- Rod Control is not required to be placed in MANUAL until a Tave loop is defeated using u-TS-412T. As long as a Tave loop is defeated, Rod Control should remain in MANUAL. This does not preclude placing rods in AUTO during rapidly changing transient conditions such as runbacks, etc. as long as rod control is returned to MANUAL when the plant is stabilized. The affected Tave loop does not need to be defeated until just prior to tripping bistables (tripping bistables will cause the N16 and Tave loop to fail low).

Examiner Note: Steps 2.3.12 and 2.3.13 will be performed by I & C Maintenance at a later time and are not included in the Scenario Guide.

	US	REFER to Technical Specifications, Section 4.1 of this procedure and Attachment 5 to determine applicable LCOAR conditions. [Step 2.3.14]
		• LCO 3.3.1, Reactor Trip System Instrumentation (Function 6, Overtemperature N-16 & 8.b, Pressurizer Pressure High).
		• CONDITION E – One channel inoperable. • ACTION E.1 – Place channel in trip within 72 hours, OR • ACTION E.2 – Be in MODE 3 within 78 hours.
		• LCO 3.3.1, Reactor Trip System Instrumentation (Function 8.a, Pressurizer Pressure Low)
		• CONDITION M – One channel inoperable. • ACTION M.1 – Place channel in trip within 72 hours, OR • ACTION M.2 – Reduce THERMAL POWER to < P-7 within 78 hours.

Operating Test :	NRC	Scenario #	1	Event #	1	Page	10	of	53
Event Description:	Pressurizer Pressure Channel (PT-455) fails high								

Time	Position	Applicant's Actions or Behavior
	US	• LCO 3.3.2, ESFAS Instrumentation (Function 1.d, Safety Injection, Pressurizer Pressure – Low).
		• CONDITION D – One channel inoperable. • ACTION D.1 – Place channel in trip within 72 hours, OR • ACTION D.2.1 – Be in MODE 3 within 78 hours, AND • ACTION D.2.2 – Be in MODE 4 within 84 hours.
	US	• LCO 3.3.2, ESFAS Instrumentation (Function 8.b, ESFAS Interlocks, Pressurizer Pressure – P-11).
		• CONDITION L – One or more required channel(s) inoperable. • ACTION L.1 – Verify interlock is in required state for existing unit condition within one hour, OR • ACTION L.2.1 – Be in MODE 3 within 7 hours, AND • ACTION L.2.2 – Be in MODE 4 within 13 hours.
	US	• LCO 3.3.3, PAM Instrumentation (Function 2, Subcooling Monitors).
		• CONDITION A – One or more Functions with one required channel inoperable. • ACTION A.1 – Restore required channel to OPERABLE status within 30 days.
Examiner Note:		**When the PORV opens and Pressurizer pressure decreases below 2220 psig with 4 Pressurizer pressure channels in service -OR- 2222 psig with 3 Pressurizer pressure channels in service LCO 3.4.1 will apply during the time pressure is low due to Pressurizer pressure being below the specified limit in the COLR.**
	US	• LCO 3.4.1, RCS Pressure, Temperature, and Departure from Nucleate Boiling (DNB) Limits
		• CONDITION A – One or more RCS DNB parameters not within limits. • ACTION A.1 – Restore RCS DNB parameter(s) to within limit in 2 hours.
	US	INITIATE a Condition Report per STA-421, as applicable. [Step 2.3.15]

Operating Test :	NRC	Scenario #	1	Event #	1	Page	11	of	53
Event Description:	Pressurizer Pressure Channel (PT-455) fails high								

Time	Position	Applicant's Actions or Behavior

When Technical Specifications are addressed, or at Lead Examiner discretion, PROCEED to Event 2.

Operating Test : NRC	Scenario # 1	Event # 2	Page 12 of 53
Event Description: CRDM Vent Fan #1 trips.			

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Event 2 (Key 2).** **- CH10, CRDM Vent Fan trips**
Indications Available: **3A-2.1 – CNTMT FN MASTER TRIP** **3A-1.3 – CRDM VENT FN 1 ∆P LO** **3A-1.6 – CRDM SHROUD EXH TEMP HI** **3B-4.2 – CRDM ANY VENT FAN DISCH TEMP HI (30 seconds later)** **1-HS-5421 CRDM VENT FN amber MISMATCH, white TRIP, and green STOP lights LIT**		
	BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE CRDM Vent Fan 1-01 tripped.
	US	DIRECT performance of ALM-0031A, 1-ALB-3A, Window 1.6 – CRDM SHROUD EXH TEMP HI -OR- 1-ALB-3A, Window 2.1 – CTMT FN MASTER TRIP
Examiner Note:		**The Unit Supervisor may direct the operator to start a fan prior to procedure direction.** **The following steps are from 1-ALB-3A, Window 1.6 – CRDM SHROUD EXH TEMP HI.**
Simulator Operator:		**When dispatched to locally inspect CRDM Vent Fan breaker, report the breaker tripped on overload.**
NOTE: The CRDM Cooling Unit Ventilation Chilled Water is supplied from the Containment fan Cooler Ventilation Chilled Water return header. Any adjustments on Containment Fan Cooler flow will also affect flow to CRDM cooling units. Normal Chilled Water supply flow is provided when three containment fan coolers are in service.		
	BOP	VERIFY at least one CRDM Vent Fan in service. [Step 1]
	BOP	• If NO fans are in service, START one CRDM Vent Fan per SOP-801A, Containment Ventilation System. [Step 1.a]

Operating Test :	NRC	Scenario #	1	Event #	2	Page	13	of	53
Event Description:	CRDM Vent Fan #1 trips.								

Time	Position	Applicant's Actions or Behavior

Examiner Note: **The crew may perform either Section 5.3.1, Control Rod Drive Mechanism Ventilation System Startup OR Section 5.3.3, Alternating Control Rod Drive Mechanism Ventilation Fans to start the Alternate Fan.**

The following steps are from SOP-801A, Containment Ventilation System, Section 5.3.1, Control Rod Mechanism Ventilation System Start-Up

CAUTION: Startup of this system may change indicated radiation levels inside containment due to mixing of noble gases from stagnant areas of air. Radiation levels reaching High Alarm on Containment Air Gaseous (1-RE-5503) OR Particulate Monitors (1-RE-5502) will cause a Containment Ventilation Isolation (CVI).

NOTE:

- At least one CACR fan should be in operation to ensure chilled water flow to the CRDM fan.
- The CRDM Ventilation Fans are placed in PULL-OUT to support CRDM Air Handling Unit (AHU) discharge damper realignment in the following step.

Time	Position	Applicant's Actions or Behavior
	BOP	IF required to align the CRDM AHU volume discharge dampers, THEN perform the following: Step is N/A [Step A]
	BOP	Prerequisites in Section 2.3 are met. [Step B]
	BOP	VERIFY the Hydrogen Purge Supply and Exhaust System is NOT in service. [Step C]
	BOP	IF a Containment Purge OR Vent is in progress, THEN perform the following: Step is N/A [Step D]

CAUTION:

- Starting a CRDM Ventilation Fan is potentially hazardous to personnel working at OR around the CRDM Air Handling Unit due to high D/P discharge pressures.
- A Plant Announcement should be made prior to starting either cooling fan to ensure personnel safety. Some of the key items to mention are ventilation changes AND hazards due to high D/P at the discharge dampers associated with starting a CRDM Vent Fan.

Time	Position	Applicant's Actions or Behavior
	US	IF placed, THEN remove standard clearances: Step is N/A [Step E]
	BOP	Make a Plant Announcement. [Step F]
	BOP	START the selected CRDM Ventilation Fan. [Step G] • PLACE 1-HS-5423, CRDM VENT FN 2 handswitch in START.
Examiner Note:		**[Step H] should not be performed as the report was given that the fan breaker tripped on overload. The affected fan should be placed in Pull-Out.**
	BOP	PLACE the remaining CRDM Ventilation Fan in AUTO. Step is N/A [Step H]
	BOP	MONITOR Containment Radiation levels until they stabilize. [Step I]
	BOP	IF a Containment Purge OR Vent is in progress AND radiation levels rise to the Alert Alarm Limit on either the Containment Air Gaseous Monitor (1-RE-5503) OR the Containment Air Particulate Monitor (1-RE-5502), THEN perform ONE of the following: Step is N/A [Step J]
	BOP	IF Containment Purge OR Vent was secured in Step D OR J, THEN: Step is N/A [Step K]
	BOP	IF CVI was disabled in Step D OR J, THEN: Step is N/A [Step L]
Examiner Note:		**The crew may perform either Section 5.3.1, Control Rod Drive Mechanism Ventilation System Startup OR Section 5.3.3, Alternating Control Rod Drive Mechanism Ventilation Fans to start the Alternate Fan.** **The following steps are from SOP-801A, Containment Ventilation System, Section 5.3.3, Alternating Control Rod Drive Mechanism Ventilation Fans.**

Operating Test : NRC	Scenario # 1	Event # 2	Page 15 of 53
Event Description: CRDM Vent Fan #1 trips.			

Time	Position	Applicant's Actions or Behavior
		CAUTION: Alternating the CRDM Ventilation Fans may change indicated radiation levels inside containment due to mixing of noble gases from stagnant areas of air. Radiation levels reaching High Alarm on Containment Air Gaseous (1-RE-5503) OR Particulate Monitors (1-RE-5502) will cause a Containment Ventilation Isolation (CVI).
	BOP	VERIFY the Hydrogen Purge Supply AND Exhaust System is NOT in service. [Step A]
	BOP	IF a Containment Purge OR Vent is in progress, THEN perform the following: Step is N/A [Step B]
	BOP	START the idle CRDM Ventilation Fan. [Step C] • 1-HS-5423, CRDM VENT FAN 2 to START
		Examiner Note: [Steps D & E] should not be performed as the report was given that the fan breaker tripped on overload. The affected fan should be placed in Pull-Out.
	BOP	STOP the other CRDM Ventilation Fan. [Step D]
	BOP	PLACE the shutdown CRDM Ventilation Fan handswitch in AUTO. [Step E]
	BOP	MONITOR Containment Radiation levels until they stabilize. [Step F]
	BOP	IF a Containment Purge OR Vent is in progress AND radiation levels rise to the Alert Alarm Limit on either the Containment Air Gaseous Monitor (1-RE-5503) OR the Containment Air Particulate Monitor (1-RE-5502), THEN perform ONE of the following: Step is N/A [Step G]
	BOP	IF Containment Purge OR Vent was secured in Step B OR G, THEN: Step is N/A [Step H]
	BOP	IF CVI was disabled in Step B OR G, THEN: Step is N/A [Step I]

Operating Test :	NRC	Scenario #	1	Event #	2	Page	16	of	53
Event Description:	CRDM Vent Fan #1 trips.								

Time	Position	Applicant's Actions or Behavior
Examiner Note:		**The next steps continue with ALM-0031A, 1-ALB-3A, Window 1.6 – CRDM SHROUD EXH TEMP HI.**
	BOP	MONITOR 1-TI-5400A, CNTMT AVE TEMP. [Step 2]
		CAUTION: Chilled Water temperature should not be allowed to increase to 100°F. Recirculation through chiller units may actuate the rupture discs.
	BOP	VERIFY X-TI-6071, CH WTR SPLY HDR TEMP is 45ºF to 55ºF at X-CV-01. [Step 3]
	BOP	ENSURE 1-FI-6081, CNTMT FN CLR CH WTR RET FLO is between 912 and 1008 GPM with any combination of 3 of 4 units in service. [Step 4]
	BOP	MONITOR CRDM Shroud exhaust temperature. [Step 5]
		• 1-TI-5455, CRDM VENT FN 2 DISCH TEMP.
	US	REFER to Technical Specifications LCO 3.6.5, Containment Air Temperature. [Step 6]
	US	CORRECT the condition or INITIATE a CR per STA-421, as applicable. [Step 7]
		When CRDM cooling is restored, or at Lead Examiner discretion, PROCEED to Event 3.

Operating Test : NRC	Scenario # 1	Event # 3	Page 17 of 53
Event Description: SG 1-04 Steam Flow (FI-542A) Fails Low			

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Event 3 (Key 3). - RX02G, Steam Generator (1-04) Steam Flow Instrument (FT-542) Fails Low**
Indications Available: **8A-4.6 – SG 4 LVL LO (clears when level restored)** **8A-4.8 – SG 4 STM & FW FLO MISMATCH** **8A-4.12 – SG 4 LVL DEV** **1-FI-542A – SG 4 STM FLO failed LOW**		
	BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE 1-FI-542A has failed low.
	BOP	PLACE 1-FK-540, SG 4 FW FLO CTRL in MANUAL and adjust for current plant conditions.
	US	DIRECT implementation of ABN-707, STEAM FLOW INSTRUMENT MALFUNCTION, Section 2, Steam Flow Instrument Malfunction
Examiner Note:		**The following steps are from ABN-707, STEAM FLOW INSTRUMENT MALFUNCTION, Section 2.0, Steam Flow Instrument Malfunction**
	BOP	VERIFY Steam Generator level is stable at program. [Step 2.3.1]
		Manually CONTROL affected feedwater control valve to maintain programmed steam generator level. [Step 2.3.1 RNO a] • 1-FK-540, SG 4 FW FLO CTRL Manually CONTROL 1-SK-509A, FWPT MASTER SPD CTRL as necessary. [Step 2.3.1 RNO b] • FWPT MASTER SPD CTRL as necessary
	BOP	VERIFY associated steam pressure channel for failed steam flow channel indicating – NORMAL (See Attachment 1) [Step 2.3.2]

Operating Test :	NRC	Scenario #	1	Event #	3	Page	18	of 53
Event Description:	SG 1-04 Steam Flow (FI-542A) Fails Low							

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY SG level on common instrument line- NORMAL (See Attachment 2) [Step 2.3.3] • LOOP 4, S/G Level Instrument LT-554 Normal
	BOP	VERIFY steam flow channel selected for control – NORMAL [Step 2.3.4]
		IF alternate steam flow channel operable, THEN SELECT alternate steam flow channel for control: [Step 2.3.4 RNO] • 1-FS-542C, SG 4 STM FLO CHAN (FY-543B, selected for control)
	BOP	RESTORE SG level control to normal: [Step 2.3.5]
		VERIFY affected Steam Generator level is stable at program level. [Step 2.3.5.a]
		ENSURE feedwater control valve in AUTO AND controlling normally. [Step 2.3.5.b] • 1-FK-540, SG 4 FW FLO CTRL
		ENSURE 1-SK-509A, FWPT MASTER SPD CTRL in AUTO AND controlling normally. [Step 2.3.5.c]
	US	INITIATE a Condition Report per STA-421, as applicable. [Step 6]

When the crew has completed the actions of ABN-707, or at Lead Examiner discretion, PROCEED to Event 4.

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Event 4 (Key 4). - RP05A, NR Cold Leg 1 Temp (TE-411B) fails low.**
Indications Available: **6D-1.10 – AVE T_{AVE} T_{REF} DEV** **6D-4.14 – CONTROL ROD BANK D FULL WITHDRWL** **1-TI-411A, CL 1 TEMP (NR) CHAN I indication failed low** **1-TI-412, RC LOOP 1 T_{AVE} CHAN I indication failed low**		
	RO	RESPOND to Annunciator Alarm Procedures.
	RO	RECOGNIZE Control Rods withdrawing due to T_{COLD} failed low.
	US	DIRECT performance of ABN-704, Tc / N-16 Instrumentation Malfunction, Section 2.0.
Examiner Note:		**The following steps are from ABN-704, Tc / N-16 Instrumentation Malfunction, Section 2.0, Tc / N-16 Instrumentation Malfunction**
NOTE:		• If the failed channel was reading lower than the substituted channel, then AVE Tave will increase when the failed channel is defeated due to another channel being substituted for the failed signal to maintain accurate averaging. • Rod Control should remain in MANUAL until all channels are operable. This does not preclude placing rods in AUTO during rapidly changing transient conditions such as runbacks, etc. as long as rod control is returned to MANUAL when the plant is stabilized.
Examiner Note:		**The RO may place 1-FK-121, Charging Flow Controller, in MANUAL to maintain PZR level on setpoint.**
	RO	PLACE 1/1-RBSS, CONTROL ROD BANK SELECT Switch in MANUAL. [Step 2.3.1]
	RO	SELECT LOOP 1 on 1-TS-412T, T_{AVE} Channel Defeat. [Step 2.3.2]

	RO/BOP	VERIFY Steam Dump System is NOT actuated and NOT armed. [Step 2.3.3]
Examiner Note:		**Tave-Tref deviation may not exceed 1°F due to Control Rod withdrawal stopping at C-11. The crew should perform a reactivity brief and perform actions to restore control rods to the pre-event position.**
	RO	RESTORE Tave to within 1°F of Tref. [Step 2.3.4]
	RO/BOP	SELECT LOOP 1 on 1/1-JS-411E, N16 Power Channel Defeat. [Step 2.3.5]
	RO	ENSURE a valid N16 channel supplying recorder on 1/1-TS-411E, 1-TR-411 CHAN SELECT. [Step 2.3.6]
	RO/BOP	VERIFY Steam Dumps not armed by observing the following light DARK: • PCIP, Window 3.4 – TURB LOAD REJ STM DMP ARMED C-7, not ARMED (DARK). [Step 2.3.7]
	US/BOP	VERIFY Steam Dumps were NOT blocked. [Step 2.3.8]
Examiner Note:		**Steps 2.3.9 and 2.3.10 will be performed by I & C Maintenance at a later time and are not included in the Scenario Guide.**
	US	EVALUATE Technical Specifications. [Step 2.3.11]
		• LCO 3.3.1.E, Reactor Trip System Instrumentation (Functions 6 & 7).
		• CONDITION E – One channel inoperable. • ACTION E.1 – Place channel in trip within 72 hours, OR • ACTION E.2 – Be in MODE 3 within 78 hours.

Operating Test :	NRC	Scenario #	1	Event #	4	Page	21 of 53
Event Description:	NR Cold Leg 1 Temp (TE-411B) fails low						

Time	Position	Applicant's Actions or Behavior
	US	INITIATE a work request per STA-606. [Step 2.3.12]
	US	INITIATE a Condition Report per STA-421. [Step 2.3.13]
When Technical Specifications are addressed, or at Lead Examiner discretion, proceed to Events 5.		

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Event 5 (Key 5).** **- FW03B, Main Feedwater Pump B trip.** **- Rods are in manual from previous event.**
Indications Available: **1-ALB-8A-1.3 – FWPT B TRIP** **1-ALB-8A-1.8 – SG 1 STM & FW FLO MISMATCH** **1-ALB-8A-2.8 – SG 2 STM & FW FLO MISMATCH** **1-ALB-8A-3.8 – SG 3 STM & FW FLO MISMATCH** **1-ALB-8A-4.8 – SG 4 STM & FW FLO MISMATCH** **1-ALB-6D-1.9 – ANY TURB RUNBACK EFFECTIVE** **1-ALB-6D-1.10 – AVE T_{AVE}-T_{REF} DEV**		
Examiner Note: **MFP A will trip 180 seconds following the trip of MFP B.**		
	RO/BOP	RESPOND to Annunciator Alarm Procedures.
	RO/BOP	RECOGNIZE trip of Main Feedwater Pump B, turbine runback in progress with control rods manual.
	US	DIRECT performance of ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 2.0, Feedwater Pump Trip.

CAUTION:
- The status of the secondary heat sink and available feedwater must be closely monitored during the performance of this procedure. The Reactor should be manually tripped if secondary heat sink cannot be maintained.
- Using Load Target to reduce load without rods in AUTO can result in excessive TAVE-TREF mismatch before C-7 activates. This mismatch may cause an SI when steam dumps trip open.

NOTE:
- Diamond step 1 denotes Initial Operator Actions.
- Should a reactor trip occur at any time during performance of this procedure, immediately proceed to EOP-0.0A/B, Reactor Trip or Safety Injection.

Time	Position	Applicant's Actions or Behavior
	◊ RO ◊ ◊ BOP ◊	VERIFY automatic plant response. [Step 2.3.1] • Control Rods in – AUTO • Turbine Runback – IN PROGRESS

Operating Test :	NRC	Scenario #	1	Event #	5	Page	23	of	53
Event Description:	Loss of MFP B								

Time	Position	Applicant's Actions or Behavior
	◊ RO ◊	IF Turbine Power is > approximately 700 MW, THEN perform the following: [Step 2.3.1 RNO] • ENSURE 1/1-RBSS, CONTROL ROD BANK SELECT in AUTO [Step 2.3.1 RNO a] • ENSURE Turbine runback to 700 MW initiated [Step 2.3.1 RNO b]
	RO	STABILIZE Reactor power using one or more of the following: [Step 2.3.2] • Control Rods • Steam Dumps • Boration • Turbine Load
Examiner Note: **MFP A will trip 180 seconds following the trip of MFP B.**		
CAUTION: • Reactor power must be established at a value within the capability of available feedwater. Auxiliary feedwater pumps can supply approximately 6% reactor power.		
	BOP	VERIFY Main Feedwater Flow to Steam Generators. [Step 2.3.3]
		• Main Feed Pump 1-01 RUNNING AND • Main Feedwater ALIGNED [Step 2.3.3.a]
NOTE: Differential pressure between feedwater and steamline may decrease following a Turbine Runback. The following computer points may aid the operator: • U5002A FW-MS HDR DP • U5003A DELTA PROGRAM-ACTUAL DP • P5446A FW STM FLOW SETPOINT		
	BOP	VERIFY feedwater header pressure greater than main steam header pressure. [Step 2.3.3.b]
	BOP	VERIFY 1-FK-2290, FWP B RECIRC FLO CTRL – CLOSED [Step 2.3.3.c]

Operating Test : NRC	Scenario # 1	Event # 5	Page 24 of 53
Event Description: Loss of MFP B			

Time	Position	Applicant's Actions or Behavior
NOTE: Control Rod insertion should be allowed to continue even if ΔI is outside the band. Continued rod insertion is required to return Tave to Tref as soon as possible so that steam demand is reduced such that One Main Feedwater Pump can maintain proper SG levels.		
	RO/BOP	VERIFY Tave - TRENDING TO TREF. [Step 2.3.4] • 1-TI-412A, AVE TAVE - TREF DEV
NOTE: Step 5 is a continuous action step.		
Examiner Note: MFP A will trip 180 seconds following the trip of MFP B.		
	BOP	MONITOR SG water level – STABLE OR TRENDING TO NORMAL OPERATING RANGE. [Step 2.3.5] • CONTROL Main Feed flow to maintain narrow range level between 60% and 75% OR • CONTROL Auxiliary Feed flow to maintain narrow range level between 60% and 75%
NOTE: Differential pressure between feedwater and steamline may decrease with only one Main Feedwater Pump in operation. The following computer points may aid the operator: • U5002A FW-MS HDR DP • U5003A DELTA PROGRAM-ACTUAL DP • P5446A FW STM FLOW SETPOINT		

Operating Test : NRC	Scenario # 1	Event # 5	Page 25 of 53
Event Description: Loss of MFP B			

Time	Position	Applicant's Actions or Behavior
	BOP	Monitor Main Feedwater response. [Step 2.3.6]
		VERIFY differential pressure between feedwater and main steam pressure 80 psid to 181 psid (P5446A) [Step 2.3.6.a]
		SG FW FLO CTRL Valves - AUTO [Step 2.3.6.b] • 1-FK-510, SG 1 FW FLO CTRL • 1-FK-520, SG 2 FW FLO CTRL • 1-FK-530, SG 3 FW FLO CTRL • 1-FK-540, SG 4 FW FLO CTRL
		VERIFY MFP flow 1-FI-2289, FWP A SUCT FLO is ≤ 22,000 gpm [Step 2.3.6.c]
	RO	VERIFY the following: [Step 2.3.7]
		• RODS - ABOVE ROD INSERTION LIMIT [Step 2.3.7.a]
		• ΔFLUX - (AFD) WITHIN LIMITS [Step 2.3.7.b]
	BOP	WHEN steam dumps close, THEN reset steam dump arming signal (C-7 interlock). [Step 2.3.8]
		• 43/1-SD, STM DMP MODE SELECT
Examiner Note: MFP A will trip 180 seconds following the trip of MFP B.		
	US	NOTIFY QSE Generation Controller and update GAPS to "Create Current Condition" for the down power. [Step 2.3.9]
	US	INITIATE equipment repairs per STA-606. [Step 2.3.10]
	US	CHECK Chemistry Sampling Requirement: [Step 2.3.11]
		• SG ARVS - REMAINED CLOSED AND • TDAFW Pump - REMAINED STOPPED [Step 2.3.11.a]

Time	Position	Applicant's Actions or Behavior
	US	VERIFY Reactor Power change – LESS THAN 15% WITHIN ONE HOUR. [Step 2.3.11.b]
	US	NOTIFY Chemistry to perform RCS Isotopic analysis for iodine between 2 and 6 hours after power change. [Step 2.3.11.b RNO]
	RO	RESET Turbine Runback per ABN-401. [Step 2.3.12]
NOTE: IF Reactor power decreased to less than 5%, THEN do not increase power until all MODE 1 AND 2 requirements are completed.		
	US	Return to procedure and step in effect AND adjust power as desired. [Step 2.3.13]
Examiner Note: The following steps are from ABN-401, Main Turbine Malfunction, Section 8.0, Turbine Reloading After Runback. These steps are used for RESET of the turbine runback.		
NOTE: • For Auto Pump Trip Runbacks, there is a 9 minute time delay before the condition will clear such that load reference can be restored. • The Runback Bar will turn white when the Runback is clear. • Do not raise Main Turbine load above the runback setpoint unless the signal which generated the runback is cleared (manual runback reset, HDP breaker racked out or HDP running, etc.). If load is raised above the runback setpoint and the signal is not cleared, a runback will be re-initiated.		
Examiner Note: MFP A will trip 180 seconds following the trip of MFP B.		
	BOP	Verify ANY TURB RUNBACK EFFECTIVE (6D-1.9) – DARK [Step 8.3.1]
	BOP	In the "Load Control" Section, ENSURE Load Rate Setpoint Controller is set to support reload or current plant conditions. [Step 8.3.2]

Operating Test :	NRC	Scenario #	1	Event #	5	Page	27	of	53
Event Description:	Loss of MFP B								

Time	Position	Applicant's Actions or Behavior
	BOP	In the "Load Control" Section, ensure the Load Target Setpoint Controller is set for actual MW. [Step 8.3.3]
	BOP	DETERMINE Manual Runback was not used. [Step 8.3.4]
	BOP	Verify the turbine runback is reset. [Step 8.3.5]
	US	Verify Runback -LESS THAN 15% WITHIN ONE HOUR. [Step 8.3.6]
	US	Notify Chemistry to perform RCS Isotopic analysis for iodine between 2 and 6 hours after power change. [Step 8.3.6 RNO]
	US	Control turbine load as required per IPO-003A/B. [Step 8.3.7]
	US	Notify Nuclear Engineering of runback. [Step 8.3.8]
	US	Initiate a SMART Form, if required per STA-421. [Step 8.3.9]
	US	Initiate repair per STA-606. [Step 8.3.10]

Examiner Note: **Events during this scenario will result in exceeding the Rod Insertion Limits (RIL). The RO should inform the SRO when ALB-6D, Window 2.7 – ANY CONTROL ROD BANK AT LO-LO LIMIT is LIT. Technical Specifications may not be referenced at this time due to the trip of MFP A, however, can be referenced upon scenario completion.**

Examiner Note: **MFP A will trip 180 seconds following the trip of MFP B.**

Operating Test :	NRC	Scenario #	1	Event #	5	Page	28	of	53
Event Description:	Loss of MFP B								

Time	Position	Applicant's Actions or Behavior
	US	EVALUATE Technical Specifications.
		• LCO 3.1.6.A, Control Bank Insertion Limits.
		• CONDITION A - Control bank insertion limits not met. • ACTION A.1.1 - Verify SDM to be within the limits provided in the COLR within one hour, <u>OR</u> • ACTION A.1.2 - Initiate Boration to restore SDM to within limit within one hour, <u>AND</u> • ACTION A.2 - Restore control bank(s) to within limits within 2 hours.
When MFP A trips, PROCEED to EVENTs 6, 7, & 8.		

Operating Test : NRC	Scenario # 1	Event # 6,7,8	Page 29 of 53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close		

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**Events 6, 7, & 8 (Key 5) are preloaded and will occur after Key 5 entered.** **- FW03A, Main Feedwater Pump A trip (180 second delay)** **- RP15E, RTBs jammed closed** **- OVRDE, Bus Breaker CS-1B4-1 fails to open** **- SG02D, SG (1-04) Tube Rupture (2 tubes)** **- FW38D, SG (1-04) FWIV fails to close automatically**
Indications Available: **1-ALB-8A-1.3 – FWPT A TRIP** **1-ALB-8A-1.8 – SG 1 STM & FW FLO MISMATCH** **1-ALB-8A-2.8 – SG 2 STM & FW FLO MISMATCH** **1-ALB-8A-3.8 – SG 3 STM & FW FLO MISMATCH** **1-ALB-8A-4.8 – SG 4 STM & FW FLO MISMATCH** **1-ALB-6D-1.9 – ANY TURB RUNBACK EFFECTIVE** **1-ALB-6D-1.10 – AVE TAVE-TREF DEV**		
	RO/BOP	RESPOND to Annunciator Alarm Procedures.
	RO/BOP	RECOGNIZE trip of Main Feedwater Pump A.
	US	DIRECT performance of ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 2.0, Feedwater Pump Trip or DIRECT a Reactor Trip.
Examiner Note:		**The following steps are from ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 2.0, Feedwater Pump Trip.**
Examiner Note:		**The crew is likely to Trip the Reactor prior to ABN response.**

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	30	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
		CAUTION: • The status of the secondary heat sink and available feedwater must be closely monitored during the performance of this procedure. The Reactor should be manually tripped if secondary heat sink cannot be maintained. • Using Load Target to reduce load without rods in AUTO can result in excessive TAVE-TREF mismatch before C-7 activates. This mismatch may cause an SI when steam dumps trip open.
		NOTE: • Diamond step 1 denotes Initial Operator Actions. • Should a reactor trip occur at any time during performance of this procedure, immediately proceed to EOP-0.0A/B, Reactor Trip or Safety Injection.
	◊ RO ◊ ◊ BOP ◊	VERIFY automatic plant response. [Step 2.3.1] • Control Rods in – AUTO • Turbine Runback – IN PROGRESS
	RO	STABILIZE Reactor power using one or more of the following: [Step 2.3.2] • Control Rods • Steam Dumps • Boration • Turbine Load
		CAUTION: • Reactor power must be established at a value within the capability of available feedwater. Auxiliary feedwater pumps can supply approximately 6% reactor power.
	BOP	VERIFY Main Feedwater Flow to Steam Generators. [Step 2.3.3]
		• NO Main Feed Pumps RUNNING [Step 2.3.3.a]
		PERFORM the following: [Step 2.3.3.a RNO a] • IF SG level is decreasing in an uncontrolled manner, THEN trip the Reactor AND GO TO EOP-0.0A.

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	31	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
<u>Simulator Operator:</u>		**The following are preloaded to prevent an automatic or manual RX trip: - RP15E, Reactor Trip Breakers jammed closed - DIED1B41, 1B4 Breaker overridden closed**
	US	DIRECT performance of EOP-0.0A, Reactor Trip or Safety Injection.
<u>Examiner Note</u>:		**The following steps are from EOP-0.0A, Reactor Trip or Safety Injection.**
<u>Examiner Note</u>:		**The reactor fails to trip from the CB handswitches at CB-07 and CB-10.**
	RO	VERIFY Reactor Trip: [Step 1]
		Verify the following: [Step 1.a] • Reactor Trip Breakers – AT LEAST ONE OPEN. • Neutron flux – DECREASING.
		• All control rod position rod bottom lights – ON [Step 1.b]
<u>Examiner Note</u>:		**Reactor fails to trip when breaker supplying CRDM MG set remains closed. Opening then closing these breakers would normally trip the CRDM MG set.**
	RO/BOP	Manually TRIP Reactor from both trip switches. [Step 1 RNO a]
		• IF reactor will not trip, THEN momentarily de-energize 480V normal switchgear 1B3 AND 1B4.
		• IF reactor NOT tripped, THEN go to FRS-0.1A, RESPONSE TO NUCLEAR POWER GENERATION/ATWT, Step 1.
<u>Examiner Note</u>:		**The following steps are from FRS-0.1A, Response To Nuclear Power Generation / ATWT.**

Operating Test : NRC	Scenario # 1	Event # 6,7,8	Page 32 of 53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close		

Time	Position	Applicant's Actions or Behavior
	RO	VERIFY Reactor Trip: [Step 1]
		• Reactor Trip Breakers – AT LEAST ONE OPEN, AND
		• Neutron flux – DECREASING, AND
		• All Control Rod Position Rod Bottom Lights – ON
CRITICAL TASK STATEMENT		**CT-1 – Ensure Control Rods Inserting ≥ 48 Steps/ Minute During Reactor Trip Failure Prior to Exiting FRS-0.1A, Response to Nuclear Power Generation / ATWT.**
CT-1	RO	IF Reactor NOT tripped, THEN ENSURE control rods INSERTING at a rate greater than or equal to 48 steps per minute. [Step 1 RNO]
Examiner Note:		**The Main Turbine will NOT automatically trip from the P-4 signal as the Reactor Trip breakers are not open. The Main Turbine may automatically trip from an AMSAC signal depending on conditions and timing. This Scenario Guide includes actions for the BOP to manually trip the turbine.**
	BOP	VERIFY Turbine Trip: [Step 2] • All HP turbine stop valves - CLOSED
		Manually TRIP Turbine. [Step 2 RNO]
	BOP	VERIFY Total AFW Flow – GREATER THEN 860 GPM: [Step 3]
	RO/BOP	INITIATE Emergency Boration of RCS. [Step 4]
Examiner Note:		**The following steps are from FRS-0.1A, Response To Nuclear Power Generation/ATWT, Attachment 1.F, Initiate Emergency Boration.**

Operating Test : NRC	Scenario # 1	Event # 6,7,8	Page 33 of 53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close		

Time	Position	Applicant's Actions or Behavior
	RO/BOP	• [1.F] ENSURE at least one Centrifugal Charging Pump – RUNNING. [Step 4.a]
		• [1.F] VERIFY Charging flow – GREATER THAN 30 GPM. [Step 4.b]
		• [1.F] ALIGN Boration flowpath: [Step 4.c]
		• [1.F] PLACE 1/1-APBA1, BA XFER PMP 1 in START. [Step 4.c.1)]
		• [1.F] PLACE 1/1-APBA2, BA XFER PMP 2 in START. [Step 4.c.1)]
		• [1.F] PLACE 1/1-8104, EMER BORATE VLV in OPEN. [Step 4.c.2)]
		• [1.F] VERIFY flow on 1-FI-183A, EMER BORATE FLO. [Step 4.c.3)]
	RO	NOTIFY Unit Supervisor Attachment 1.F instructions complete <u>AND</u> Emergency Boration has been initiated.
	US/RO	CHECK Pressurizer pressure – LESS THAN 2335 psig [Step 5]
<u>Simulator Operator</u>: Two minutes after being contacted to locally trip the Reactor AND after Emergency Boration is initiated, EXECUTE remote functions RPR112 and RPR113 (Key 10), Local Reactor Trip.		
<u>Examiner Note</u>: When the Reactor Trip Breakers are locally opened a Tube Rupture will occur on SG 1-04 (2 Tubes). This will require the crew to initiate Safety Injection upon transition back to EOP-0.0A, Reactor Trip or Safety Injection.		
	US/RO	CHECK If The Following Trips Have Occurred: [Step 6]
		• Reactor – TRIPPED [Step 6.a]

	RO	DISPATCH operator to locally trip Reactor. [Step 6.a RNO a]
		• At reactor switchgear:
		  • Trip reactor trip and bypass breakers A and B
		  • Stop Rod Drive MG sets 1 and 2
		• At normal switchgear
		  • Trip Rod drive MG sets 1 and 2 motor breakers on 1B3/8C/BKR and 1B4/8C/BKR

	BOP	Turbine – TRIPPED [Step 6.b]

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	34	of 53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close							

Time	Position	Applicant's Actions or Behavior
		CAUTION: If an SI signal exists or occurs, 1 through 8 of EOP-0.0A REACTOR TRIP OR SAFETY INJECTION should be performed while continuing with this procedure.
		Simulator Operator: If SI is initiated during performance of FRS-0.1A the Unit Supervisor may request Unit 2 perform steps 1-8 of EOP-0.0A. Acknowledge the request as the Unit 2 Unit Supervisor.
	RO/BOP	Verify Containment Ventilation Isolation - APPROPRIATE MLB LIGHT INDICATION (GREEN WINDOWS) [Step 7]
		CHECK If Reactor Is Subcritical: [Step *8]
	RO	• Power Range indication – LESS THAN 5%. [Step 8.a]
	RO	• Intermediate Range Channels – NEGATIVE STARTUP RATE. [Step 8.b]
	US	• GO to Step 18. [Step 8.c]
		CHECK IF RCPs Should Be Stopped [Step 18]
	RO	• RCS subcooling less than 25ºF (55ºF FOR ADVERSE CONTAINMENT). [Step 18.a]
	US	• RNO GO to Step 18.d. [Step 18.a RNO a]
	RO	• RCP Operating Parameters – WITHIN LIMITS [Step 18.d]
		CAUTION: Boration should continue to obtain adequate shutdown margin during subsequent actions.

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	35	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
	US/RO	RETURN to Procedure and Step in Effect. [Step 19]
Examiner Note:		**The following steps are from EOP-0.0A, Reactor Trip or Safety Injection. The crew should diagnose lowering Pressurizer pressure due to the SG 1-04 Tube Rupture and manually initiate Safety Injection during the performance of the first four steps.**
		VERIFY Reactor Trip: [Step 1]
	RO	Verify the following: [Step 1.a] • Reactor Trip Breakers – AT LEAST ONE OPEN. • Neutron flux – DECREASING.
	RO	• ALL Control Rod Position Rod Bottom Lights – ON. [Step 1.b]
	BOP	VERIFY Turbine Trip: [Step 2]
		• ALL HP Turbine Stop Valves – CLOSED.
		VERIFY Power to AC Safeguards Buses: [Step 3]
	BOP	AC Safeguards Buses – AT LEAST ONE ENERGIZED. [Step 3.a] • AC safeguards bus voltage- 6900 Volts(6500-7100 Volts)
	BOP	AC Safeguards Buses – BOTH ENERGIZED. [Step 3.b]
	RO	CHECK SI status: [Step 4]
		CHECK if SI is Actuated. [Step 4.a]
		• SI actuation as indicated on the First Out Annunciator 1-ALB-6C • SI Actuated blue status light - ON
	RO	VERIFY Both Trains SI Actuated: [Step 4.b]
		• SI Actuated blue status light – ON NOT FLASHING.
Examiner Note:		**EOP-0.0A, Attachment 2 steps are performed by the BOP and are identified in the last section.**

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	36	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
		CAUTION: A Safety Injection actuation will affect normal egress from the Containment Building. Attachment 9 of this procedure provides instructions to evacuate personnel from the Containment during a Safety Injection actuation.
		NOTE: Attachment 2 is required to be completed before FRGs are implemented unless directed by this procedure.
	US/BOP	INITIATE Proper Safeguards Equipment Operation Per Attachment 2 [Step 5]
		VERIFY AFW Alignment: [Step *6]
	BOP	• MDAFW Pump 1-01 – RUNNING [Step 6.a]
	BOP	• TDAFW Pump - RUNNING IF NECESSARY [Step 6.b]
	BOP	• AFW total flow – GREATER THAN 460 gpm [Step 6.c]
	BOP	• AFW valve alignment - PROPER ALIGNMENT [Step 6.d]
		VERIFY Containment Spray NOT Required: [Step *7]
	BOP	• Containment pressure – HAS REMAINED LESS THAN 18.0 PSIG [Step 7.a] • 1-ALB-2B window 1.8, CS ACT - NOT ILLUMINATED • 1-ALB-2B window 4.11, CNTMT ISOL PHASE B ACT – NOT ILLUMINATED • Containment Pressure – LESS THAN 18.0 PSIG
	BOP	• VERIFY Containment Spray Heat Exchanger Outlet Valves - CLOSED. [Step 7.b]
	BOP	• VERIFY Containment Spray Pumps – RUNNING. [Step 7.c]

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	37	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
	RO	CHECK If Main Steamlines Should Be ISOLATED: [Step *8]
		• VERIFY the following: [Step 8.a] • Containment pressure – GREATER THAN 6.0 PSIG. • Steamline pressure – LESS THAN 610 PSIG
	US	GO to Step 9 [Step 8.a RNO a]
		CHECK RCS Temperature: [Step *9]
	RO	• RCS AVERAGE TEMPERATURE STABLE AT OR TRENDING TO 557°F
		IF temperature less than 557°F and decreasing, THEN perform the following: [Step 9 RNO]
	BOP	• Stop dumping steam. [Step 9 RNO a]
	BOP	• IF cooldown continues, THEN reduce total AFW flow as necessary to minimize the cooldown: [Step 9 RNO b]
		• Maintaining a minimum of 460 gpm UNTIL narrow range level greater than 43% (50% FOR ADVERSE CONTAINMENT) in at least one SG.
		• As necessary to maintain SG levels WHEN narrow range level greater than 43% (50% FOR ADVERSE CONTAINMENT) in at least one SG.
		• IF TDAFW pump is not required to maintain greater than 460 gpm flow, THEN stop TDAFW pump.
	BOP	• IF cooldown continues, THEN close main steamline isolation valves. [Step 9 RNO c]
		CHECK PRZR Valve Status: [Step 10]
	RO	• PRZR Safeties – CLOSED. [Step 10.a]
	RO	• Normal PRZR Spray Valves – CLOSED. [Step 10.b]
	RO	• PORVs – CLOSED. [Step 10.c]
	RO	• Power to at least 1 Block Valve – AVAILABLE. [Step 10.d]
	RO	• Block Valves – AT LEAST ONE OPEN. [Step 10.e]

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	38	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
	RO	CHECK If RCPs Should Be Stopped: [Step 11]
		• RCS subcooling - LESS THAN 25°F (55°F FOR ADVERSE CONTAINMENT) : [Step 11.a]
		• GO to Step 12. : [Step 11.a RNO a]
	US/RO	CHECK if any SG is Faulted: [Step 12]
		• Check pressures in all SGs: [Step 12.a] • ANY SG PRESSURE DECREASING IN AN UNCONTROLLED MANNER • ANY SG COMPLETELY DEPRESSURIZED
		• GO to Step 13. [Step 12.a RNO a]
	US/RO	CHECK if SG Tubes are Not Ruptured: [Step 13]
		• Condenser off gas radiation - NORMAL (COG-182, 1RE-2959) • Main steamline radiation - NORMAL (MSL-178 through 181, 1RE-2325 through 2328) • SG blowdown sample radiation monitor - NORMAL (SGS-164, 1RE-4200) • No Steam Generator level increasing in an uncontrolled manner
		• Go to EOP-3.0A, STEAM GENERATOR TUBE RUPTURE, Step 1. [Step 13 RNO]
<u>Examiner Note</u>: EOP-3.0, Steam Generator Tube Rupture steps begin here.		
	RO/BOP	Check If RCPs Should Be Stopped: [Step *1]
		• RCS subcooling -LESS THAN 25°F (55°F FOR ADVERSE CONTAINMENT) [Step 1.a]
		• Go to Step 2. [Step 1.a RNO a]
CRITICAL TASK STATEMENT		**CT-2 – Identify and isolate the Ruptured Steam Generator Prior to Commencing an Operator Induced Cooldown per EOP-3.0A, Steam Generator Tube Rupture.**

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	39	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
CT-2	RO/BOP	Identify Ruptured SG(s): SG 1-04 is the only ruptured generator. [Step *2] • Unexpected increase in any SG narrow range level -OR- • High radiation from any SG blowdown sample line. (SGS-164, 1-RE-4200) -OR- • High radiation from any Main steamline. (MSL-178 through 181, 1-RE-2325 through 2328)
CT-2		Identified 1-04 Steam Generator Tubes are ruptured.
		CAUTION: If the TDAFW pump is the only available source of feed flow, steam supply to the TDAFW pump must be maintained from at least one SG.
		CAUTION: At least two SG(s) must be maintained available for the initial RCS cooldown. At least one SG must be maintained available for the subsequent RCS cooldown to RHR system operating conditions.
		NOTE: If any SG atmospheric opens the Plant Staff should be notified.
	RO/BOP	Isolate Flow From Ruptured SG(s): [Step 3]
CT-2		• Adjust ruptured SG 1-04 atmospheric controller setpoint to 1160 psig. [Step 3.a]
		• Check ruptured SG 1-04 atmospheric - CLOSED [Step 3.b]
CT-2		• Close ruptured SG 1-04 main steamline isolation, and SG drippot isolation valves [Step 3.c]
CT-2		• Pull-Out steam supply valve handswitch from ruptured SG 1-04 to Turbine Driven AFW pump. [Step 3.d]

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	40	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
CT-2		• Verify blowdown isolation valve(s) from ruptured SG 1-04 - CLOSED [Step 3.e]
		CAUTION: If any ruptured SG is faulted, feed flow to that SG should remain isolated during subsequent recovery actions unless needed for RCS cooldown.
	RO/BOP	Check Ruptured SG 1-04 Level: [Step *4]
		• Narrow range level - GREATER THAN 43% (50% FOR ADVERSE CONTAINMENT) [Step 4.a]
CT-2		• Perform the following: [Step 4.a RNO a] • Maintain AFW flow to ruptured SG 1-04 until level greater than 43% (50% FOR ADVERSE CONTAINMENT) [Step 4.a RNO a.1)] • WHEN ruptured SG level greater than 43% (50% FOR ADVERSE CONTAINMENT), THEN stop AFW flow to ruptured SG 1-04. [Step 4.a RNO a.2)] • Go to Step 5. OBSERVE CAUTION PRIOR TO STEP 5. [Step 4.a RNO a.3)]
CT-2		• Stop AFW flow to ruptured SG 1-04. [Step 4.b]
		CAUTION: Major steam flow paths from the ruptured SG(s) should be isolated before initiating RCS cooldown.
	RO/BOP	Check Ruptured SG(s) Pressure - GREATER THAN 420 PSIG. [Step 5]

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	41	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
		CAUTION: If RCPs are NOT running, the following steps may cause a false INTEGRITY STATUS TREE (FRP) indication for the ruptured loop. Disregard ruptured loop Cold Leg Wide Range Temperature indication until after performing Step 34.
		NOTE: After the low steamline pressure SI signal is blocked, main steamline isolation will occur if the high steam pressure rate setpoint is exceeded.
	RO/BOP	Initiate RCS Cooldown: [R] [Step *6]
		• Check PRZR pressure - LESS THAN 1960 PSIG [Step 6.a]
		• Block low steamline pressure SI signal [Step 6.b]
	US	• Determine required core exit temperature from Table 1. [Step 6.c]
		Examiner Note: When ruptured Steam Generator pressure is between two values provided on the Table at Step 6.c, the correlating Core Exit Temperature for the lower pressure value is used. SG Pressure ___________.
		Examiner Note: Required CET Temp _____________.

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	42	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior

TABLE 1

LOWEST -RUPTURED SG PRESSURE (PSIG)	CORE EXIT TEMPERATURE (°F)
1200	523°F (493°F for Adverse Containment)
1150	518°F (487°F for Adverse Containment)
1100	512°F (481°F for Adverse Containment)
1050	507°F (475°F for Adverse Containment)
1000	501°F (469°F for Adverse Containment)
950	495°F (462°F for Adverse Containment)
900	488°F (454°F for Adverse Containment)
850	482°F (447°F for Adverse Containment)
800	475°F (440°F for Adverse Containment)
750	467°F (431°F for Adverse Containment)
700	459°F (421°F for Adverse Containment)
650	450°F (412°F for Adverse Containment)
600	441°F (402°F for Adverse Containment)
550	431°F (391°F for Adverse Containment)
500	421°F (380°F for Adverse Containment)
450	409°F (366°F for Adverse Containment)
420	402°F (358°F for Adverse Containment)

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	43	of 53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close							

Time	Position	Applicant's Actions or Behavior
	RO/BOP	• Dump steam to condenser from intact SGs 1-01, 1-02, and 1-03 at maximum rate and avoid main steam isolation. [Step 6.d]
	RO/BOP	• Transfer Steam Dump to steam pressure mode. [Step 6.d.1)] • Place the steam pressure controller in manual and increase demand. [Step 6.d.2)] • When P-12 (553°F TAVG) is reached select bypass interlock on Steam Dumps and continue cooldown. [Step 6.d.3)]
		• Place all PRZR heater switches to OFF position. [Step 6.e]
		• Core exit TCs - LESS THAN REQUIRED TEMPERATURE [Step 6.f]
		• Perform the following: [Step 6.f RNO f] • WHEN core exit TCs less than required temperature, THEN perform steps 6.g and 6.h [Step 6.f RNO f.1)] • Go to Step 7. [Step 6.f RNO f.2)]
		• Stop RCS cooldown. [Step 6.g]
		• Maintain core exit TCs - LESS THAN REQUIRED TEMPERATURE [Step 6.h]
	RO/BOP	Check Intact SG Levels: [Step *7]
		• Narrow range level - GREATER THAN 43% (50% FOR ADVERSE CONTAINMENT) [Step 7.a]
		• Maintain total AFW flow greater than 460 gpm until narrow range level greater than 43% (50% FOR ADVERSE CONTAINMENT) in at least one intact SG 1-01, 1-02 or 1-03. [Step 7.a RNO a]
		• Control AFW flow to maintain narrow range level between 43% and 60%. [Step 7.b]

CAUTION: If any PRZR PORV opens because of high PRZR pressure. Step 8b should be repeated after pressure decreases to less than the PORV setpoint.

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	44	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
	RO/BOP	Check PRZR PORVs and Block Valves: [Step *8]
		• Power to block valves - AVAILABLE [Step 8.a]
		• PORVs - CLOSED [Step 8.b]
		• Block valves - AT LEAST ONE OPEN [Step 8.c]

CAUTION: If offsite power is lost after SI reset, manual action may be required to restart safeguards equipment.

CAUTION: Attachment 9 of EOP-0.0A, REACTOR TRIP OR SAFETY INJECTION provides guidance to realign equipment after SI signal has been reset. This attachment should be referenced as necessary to establish support conditions and equipment restoration.

Examiner Note: EOP-3.0, Attachment 1D may be handed off to BOP to perform steps 9 thru 14

Time	Position	Applicant's Actions or Behavior
	RO/BOP	[1.D] CHECK If Diesels Should Be Emergency Started: [Step 9]
		• CHECK diesel generator(s) – RUNNING [Step 9.a]
		• PLACE D/G EMER STOP/START handswitch(es) in START. [Step 9.b]
	RO/BOP	[1.D] RESET SI. [Step 10]
	RO/BOP	[1.D] RESET SI Sequencers. [Step 11]
	RO/BOP	[1.D] RESET Containment Isolation Phase A and Phase B. [Step 12]

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	45	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
	RO/BOP	[1.D] RESET Containment Spray Signal. [Step 13]
	RO/BOP	[1.D] ESTABLISH Instrument Air and Nitrogen To Containment: [Step 14]
		• ESTABLISH instrument air: [Step 14.a] • VERIFY air compressor running. -AND- • ESTABLISH instrument air to containment.
		• ESTABLISH nitrogen: [Step 14.b] • VERIFY ACCUM 1-4 VENT CTRL, 1-HC-943 - CLOSED [Step 14.b.1)] • OPEN SI/PORV ACCUM N2 ISOL VLV, 1/1-8880 [Step 14.b.2)]
CAUTION: RCS pressure should be monitored. If RCS pressure decreases in an uncontrolled manner to less than 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT), the RHR pumps must be manually restarted to supply water to the RCS.		
	RO/BOP	Check If RHR Pumps Should Be Stopped: [Step *15]
		• RHR pumps - ANY RUNNING WITH SUCTION ALIGNED TO RWST [Step 15.a]
		• RCS pressure - GREATER THAN 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT) [Step 15.b]
		• Stop RHR pumps and place in standby. [Step 15.c]
		• Reset RHR auto switchover. [Step 15.d]

Operating Test :	NRC	Scenario #	1	Event #	6,7,8	Page	46	of	53
Event Description:	Loss of MFP A, Reactor Fails to trip, Reactor trip breakers fail to open, Bus breaker CS-1B4-1 fails to open, Steam Generator 1-04 Tube Rupture, SG 1-04 FWIV Fails To Close								

Time	Position	Applicant's Actions or Behavior
	RO/BOP	Check If RCS Cooldown Should Be Stopped: [Step 16]
		• Core exit TCs - LESS THAN REQUIRED TEMPERATURE [Step 16.a]
		• DO NOT proceed until core exit TCs less than required temperature. [Step 16.a RNO]
		• Verify Steps 6g and 6h complete. [Step 16.b]
	RO/BOP	Check Ruptured SG 1-04 Pressure - STABLE OR INCREASING [Step 17]
	RO/BOP	Check RCS Subcooling - GREATER THAN 45°F (75°F FOR ADVERSE CONTAINMENT) [Step 18]
<u>Examiner Note</u>: EOP-3.0, Attachment 1E may be handed off to perform step 19		

Time	Position	Applicant's Actions or Behavior
	RO/BOP	[1.E] Depressurize RCS To Minimize Break Flow and Refill PRZR: [Step 19]
		• Normal PRZR spray - AVAILABLE [Step 19.a]
		• Spray PRZR with maximum available spray until ANY of the following conditions satisfied: [Step 19.b] • BOTH of the following: 1) RCS pressure - LESS THAN RUPTURED SG 1-04 PRESSURE 2) PRZR level - GREATER THAN 13% (34% FOR ADVERSE CONTAINMENT) -OR- • BOTH of the following: 1) RCS pressure - WITHIN 300 PSIG OF RUPTURED SG 1-04 PRESSURE 2) PRZR level - GREATER THAN 43% (50% FOR ADVERSE CONTAINMENT) -OR- • PRZR level - GREATER THAN 75% (65% FOR ADVERSE CONTAINMENT) -OR- • RCS subcooling - AT 25°F (55°F FOR ADVERSE CONTAINMENT)
		• Close spray valve(s): [Step 19.c] 1) Normal spray valves

Scenario will be terminated when the operators have completed an RCS cooldown, and an RCS depressurization has begun, or at Lead Examiner's discretion.

Operating Test :	NRC	Scenario #	1	Event #	N/A	Page	48	of	53
Event Description:	EOP-0.0A Attachment 2								

Time	Position	Applicant's Actions or Behavior
Examiner Note: These steps are performed by the BOP per EOP-0.0A, Attachment 2.		
CAUTION: If during performance of this procedure the SI sequencer fails to complete its sequence, Attachment 3 may be used to ensure proper equipment operation for major equipment.		
	BOP	VERIFY SSW Alignment: [1]
		• VERIFY SSW Pumps – RUNNING. [1.a]
		• VERIFY EDG Cooler SSW Return Flow. [1.b]
	BOP	VERIFY Safety Injection Pumps – RUNNING. [2]
	BOP	VERIFY Containment Isolation Phase A – APPROPRIATE MLB LIGHT INDICATION (RED WINDOWS). [3]
	BOP	VERIFY Containment Ventilation Isolation – APPROPRIATE MLB LIGHT INDICATION (GREEN WINDOWS). [4]
	BOP	VERIFY CCW Pumps – RUNNING. [5]
	BOP	VERIFY RHR Pumps – RUNNING. [6]
	BOP	VERIFY Proper CVCS Alignment: [7]
		• VERIFY CCPs – RUNNING. [7.a]
		• VERIFY Letdown Relief Valve Isolation: [7.b]
		• Letdown Orifice Isolation Valves – CLOSED. [7.b.1)]
		• Letdown Isolation Valves 1/1-LCV-459 & 1/1-LCV-460 – CLOSED. [7.b.2)]

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY ECCS flow: [8]
		• CCP SI flow indicator – CHECK FOR FLOW. [8.a]
		• RCS pressure – LESS THAN 1700 PSIG (1800 PSIG FOR ADVERSE CONTAINMENT). [8.b]
		• SIP discharge flow indicator – CHECK FOR FLOW. [8.c]
		• RCS pressure – LESS THAN 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT). [8.d]
		• GO to Step 9. [8.d.RNO]
	BOP	VERIFY Feedwater Isolation Complete: [9]
		• Feedwater Isolation Valves – CLOSED.
		• Manually close 1-HV-2137, SG 1-04 FWIV.
		• Feedwater Isolation Bypass Valves – CLOSED.
		• Feedwater Bypass Control Valves – CLOSED.
		• Feedwater Control Valves – CLOSED.
	BOP	VERIFY Diesel Generators – RUNNING. [10]
	BOP	VERIFY Monitor Lights for SI Load Shedding on 1-MLB-9 and 1-MLB10 – LIT. [11]

NOTE: The MLB indication for SI alignment includes components which may be in a different alignment to support unit conditions. MSIVs, MSLs BEF MSIV D/POT ISOL, TDAFWP STEAM SUPPLIES, TDAFWP RUN, MDAFWP FLO CTRL VLVs and TDAFWP FLO CTRL VLVs may be exceptions to the expected MLB indication.

	BOP	VERIFY Proper SI alignment – PROPER MLB LIGHT INDICATION. [12]

Operating Test :	NRC	Scenario #	1	Event #	N/A	Page	50	of	53
Event Description:	EOP-0.0A Attachment 2								

Time	Position	Applicant's Actions or Behavior

NOTE: Any previously removed missile shield(s) that affects the Control Room, Auxiliary, Safeguards or Fuel Building pressure boundary is required to be restored upon initiation of a Safety Injection Signal.

NOTE: When the SI sequencer has timed out,the Reactor Makeup Water Pump with its handswitch in Auto will restart.

Time	Position	Location	Equipment	Description	Condition
	BOP	VERIFY Components on Table 1 are Properly Aligned. [13]			
		Location	Equipment	Description	Condition
		CB-03	X-HS-5534	H2 PRG SPLY FN 4	STOPPED
		CB-03	X-HS-5532	H2 PRG SPLY FN 3	STOPPED
		CB-04	1/1-8716A	RHRP 1 XTIE VLV	OPEN
		CB-04	1/1-8716B	RHRP 2 XTIE VLV	OPEN
		CB-06	1/1-8153	XS LTDN ISOL VLV	CLOSED/ H.S. in CLOSED
		CB-06	1/1-8154	XS LTDN ISOL VLV	CLOSED/ H.S. in CLOSED
		CB-07	1/1-RTBAL	RX TRIP BKR	OPEN
		CB-07	1/1-RTBBL	RX TRIP BKR	OPEN
		CB-07	1/1-BBAL	RX TRIP BYP BKR	OPEN/DEENERGIZED
		CB-07	1/1-BBBL	RX TRIP BYP BKR	OPEN/DEENERGIZED
		CB-08	1-HS-2397A	SG 1 BLDN HELB ISOL VLV	CLOSED
		CB-08	1-HS-2398A	SG 2 BLDN HELB ISOL VLV	CLOSED
		CB-08	1-HS-2399A	SG 3 BLDN HELB ISOL VLV	CLOSED
		CB-08	1-HS-2400A	SG 4 BLDN HELB ISOL VLV	CLOSED
		CB-08	1-HS-2111C	FWPT A TRIP	TRIPPED
		CB-08	1-HS-2112C	FWPT B TRIP	TRIPPED
		CB-09	1-HS-2490	CNDS XFER PUMP	STOPPED (MCC deenergized on SI)
		CV-01	X-HS-6181	PRI PLT SPLY FN 17 & INTK DMPR	STOPPED/DEENERGIZED

Operating Test : NRC	Scenario # 1	Event # N/A	Page 51 of 53
Event Description: EOP-0.0A Attachment 2			

Time	Position	Applicant's Actions or Behavior

	CV-01	X-HS-6188	PRI PLT SPLY FN 18 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6195	PRI PLT SPLY FN 19 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6202	PRI PLT SPLY FN 20 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6209	PRI PLT SPLY FN 21 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6216	PRI PLT SPLY FN 22 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6223	PRI PLT SPLY FN 23 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6230	PRI PLT SPLY FN 24 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-3631	UPS & DISTR RM A/C FN 1 & BSTR FN 42	STARTED
	CV-01	X-HS-3632	UPS & DISTR RM A/C FN 2 & BSTR FN 43	STARTED
	CV-01	1-HS-5600	ELEC AREA EXH FN 1	STOPPED/DEENERGIZED
	CV-01	1-HS-5601	ELEC AREA EXH FN 2	STOPPED/DEENERGIZED
	CV-01	1-HS-5602	MS & FW PIPE AREA EXH FN 3 & EXH DMPR	STOPPED/DEENERGIZED
	CV-01	1-HS-5603	MS & FW PIPE AREA EXH FN 4 & EXH DMPR	STOPPED/DEENERGIZED
	CV-01	1-HS-5618	MS & FW PIPE AREA SPLY FN 17	STOPPED/DEENERGIZED
	CV-01	1-HS-5620	MS & FW PIPE AREA SPLY FN 18	STOPPED/DEENERGIZED
	CV-03	X-HS-5855	CR EXH FN 1	STOPPED/DEENERGIZED
	CV-03	X-HS-5856	CR EXH FN 2	STOPPED/DEENERGIZED
	CV-03	X-HS-5731	SFP EXH FN 33	STOPPED/DEENERGIZED
	CV-03	X-HS-5733	SFP EXH FN 34	STOPPED/DEENERGIZED
	CV-03	X-HS-5727	SFP EXH FN 35	STOPPED/DEENERGIZED
	CV-03	X-HS-5729	SFP EXH FN 36	STOPPED/DEENERGIZED

Operating Test :	NRC	Scenario #	1	Event #	N/A	Page	52	of 53
Event Description:	EOP-0.0A Attachment 2							

Time	Position	Applicant's Actions or Behavior			
<u>Examiner Note</u>: The next four (4) steps would be performed on Unit 2.					
		CB-03	2-HS-5538	AIR PRG EXH ISOL DMPR	CLOSED
		CB-03	2-HS-5539	AIR PRG EXH ISOL DMPR	CLOSED
		CB-03	2-HS-5537	AIR PRG SPLY ISOL DMPR	CLOSED
		CB-03	2-HS-5536	AIR PRG SPLY ISOL DMPR	CLOSED
	BOP	NOTIFY Unit Supervisor attachment instructions complete <u>AND</u> to IMPLEMENT FRGs as required.			
EOP-0.0A, Attachment 2 steps are now complete.					

```
;2017 NRC Scenario 1
;Rev. 0

;Initialize to IC-18

;Setup: MDAFWP 1-02 in Pull-Out – Breaker Deenergized
IRF FWR021 f:0

;Event 1 - PT-455 fails high
IMF RX08A f:2500 k:1

;Event 2 – CRDM Vent Fan Trip
IMF CH10 f:1 k:2

;Event 3 - SG 1-04 Steam Flow Channel Failure Low
IMF RX02G f:0 k:3

;Event 4 - NR Cold Leg Loop 1 Fail low (TE-411B)
IMF RP05A f:510 k:4

;Event 5 - MFW Pump B Trips
IMF FW03B f:1 k:5

;Event 6 – MFW Pump A Trips, ATWT

;MFW Pump A Trips
IMF FW03A f:1 d:180 k:5

;Reactor Trip Breakers Jammed Closed
IMF RP15E f:1

;1B4 Breaker Overridden in Close
IOR DIED1B41 f:3

;Open RTBs Locally
IRF RPR112 f:2 k:10
IRF RPR113 f:2 k:10

;Event 7 – SG 1-04 SGTR (2 tubes)
{LORPRTBAL_1.Value=1} IMF SG02D f:2 r:60

;Event 8 – SG 1-04 FWIV Fails to Close
IMF FW38D f:1

;Allow 2137 to close
{DIFWHS2137.Value=0} DMF FW38D
```

GUARDED EQUIPMENT MANAGEMENT (GEM) SIGN POSTING LOG

REASON FOR POSTING MDAFW Pump 1-02

Component to be Posted	Nomenclature	Posting Installed	Posting Checked	Posting Removed
		Initial	Initial	Initial
1-HS- 2450A	MDAFW Pump 1-01	OPR	BOF	

Authorized By: Unit Superviser Date: Today Posting Removal Authorized By:________ Date:________

Open Narrative Log Entry Entered ☒ Open Narrative Log Entry Closed ☐

Comments:________

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

INTEGRATED PLANT OPERATING PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS ____________ / ______ LATEST PCN/EFFECTIVE DATE PCN-1 / 10/19/16 1200 |

LEVEL OF USE:
CONTINUOUS USE

QUALITY RELATED

POWER OPERATIONS

PROCEDURE NO. IPO-003A

REVISION NO. 30

EFFECTIVE DATE: 5/10/16 1200

PREPARED BY (Print): J. D. Stone EXT: 0564

TECHNICAL REVIEW BY (Print): Robert Clark EXT: 6155

APPROVED BY: J. Rasmussen for D. McGaughey DATE: 2/15/16
DIRECTOR, OPERATIONS

TABLE OF CONTENTS

7.0 ATTACHMENTS (Continued)

[C]
1.0 APPLICABILITY

This procedure describes steps for latching the Main Turbine, increasing power to 100% and decreasing power from 100% to MODE 3. This procedure is a trigger procedure for Technical Specification Surveillance Requirements (TS SR) 3.2.3.1, 3.3.1.2.2a, 3.3.1.2.6, 3.3.1.2.7, 3.3.1.7.5, 3.3.1.7.6, 3.3.1.7.7, 3.3.1.10.6, 3.3.1.10.7, 3.3.1.11.2a, 3.3.1.11.4, 3.3.1.15.16a, 3.3.1.15.16b, 3.4.1.4, 3.4.16.1, 3.4.16.2, and 3.7.5.1, and Technical Requirements Manual Surveillances (TRS) 13.3.33.1, 13.3.34.1 and Offsite Dose Calculation Manual (ODCM) 4.11.2.1.1.2 and 4.11.2.1.1.3. This procedure is covered by SOER 07-01 REC 1 and REC 2.

2.0 PREREQUISITES

2.1 Rod control system is in manual. ______/_____ Initials Date

2.2 Reactor power is being maintained at approximately 2-3%. ______/_____ Initials Date

2.3 Pressurizer pressure is being maintained between 2220 psig and 2250 psig. ______/_____ Initials Date

2.4 Pressurizer level is being maintained at programmed level. ______/_____ Initials Date

2.5 SGs are being maintained between 60% and 75%. ______/_____ Initials Date

2.6 FWIVs are open with at least one Main Feedwater Pump in operation. ______/_____ Initials Date

2.7 At least one Condensate Pump is in operation. ______/_____ Initials Date

2.8 A sufficient number of Circulating Water Pumps are in operation to optimize efficiency per TDM-310A. ______/_____ Initials Date

2.9 Moisture Separator Reheater prewarming has been initiated. ______/_____ Initials Date

2.10 The Main Generator has been filled with hydrogen. ______/_____ Initials Date

2.11 The Turbine Plant Cooling Water System has been lined up for power operations. ______/_____ Initials Date

2.12 Attachment 1 has been initiated. ______/_____ Initials Date

2.13 The Turbine Trip and Runback systems are in service:

☐ • REVIEW TG Prot Detail Display for existing trips.

☐ • On the Load Detail Display - Auto Runback Enable control is ON (Red).

_____/_____ Initials Date

2.14 Isolated Phase Bus Duct Cooling System in service per SOP-611A. _____/_____ Initials Date

[C] 2.15 ENSURE <u>ALL</u> FWIV N_2 pressures $\geq$1250 psig. <u>IF</u> FWIV pressure <1250 psig, THEN contact Prompt Team to restore pressure per MSM-CO-6860:

- 1-HS-2134, FWIV 1 - N_2 pressure $\geq$1250 psig _____/_____ Initials Date
- 1-HS-2135, FWIV 2 - N_2 pressure $\geq$1250 psig _____/_____ Initials Date
- 1-HS-2136, FWIV 3 - N_2 pressure $\geq$1250 psig _____/_____ Initials Date
- 1-HS-2137, FWIV 4 - N_2 pressure $\geq$1250 psig _____/_____ Initials Date

2.16 <u>IF</u> startup is following a refueling outage, <u>THEN</u> ENSURE NUC-101 is referenced for testing and hold points during power ascension. _____/_____ Initials Date

2.17 VERIFY the Generator Hydrogen System is in operation per SOP-406A. _____/_____ Initials Date

2.18 VERIFY the Generator Seal Oil System is in operation per SOP-407A. _____/_____ Initials Date

2.19 VERIFY the Generator Primary Water System is in operation per SOP-408A. (With Primary Water Flow trips blocked (Red) on Primary Water Display)

_____/_____ Initials Date

[C]

2.20 Prior to or immediately following each Refueling Outage, plus any time maintenance work is performed on the front standard, an actual Overspeed trip test shall be conducted to verify that the Overspeed trip used for primary protection operates in accordance with CPNPP specifications (Nuclear Electric Insurance Limited Standards 2.2.5.3.3.3).
<u>IF</u> it is determined that an actual Turbine Overspeed is required,
<u>THEN</u>
PERFORM an actual turbine overspeed trip test per Attachment 4. _____/_____ Initials Date

2.21 IF power ascension is being performed with a positive Moderator Temperature Coefficient, THEN ENSURE a brief for the control of the RCS temperature and reactivity with a positive Moderator Temperature Coefficient is conducted.

______/______
Initials Date

2.22 In JC-41, ENSURE Turbine Digital Control Revision Keyswitches (3) are OFF.

______/______
Initials Date

2.23 On the TSE Margin Display, ENSURE TSE Influence is ON (Red).

______/______
Initials Date

[C] 2.24 ENSURE Main Turbine, Control Fluid and Lube Oil pumps prepared for startup.

- PERFORM the Main Turbine Oil Checks on the following pumps:
- Control Fluid Pumps per SOP-401A.

  ______/______
  Initials Date

- Aux Lube Oil Pumps and DC Emergency Lube Oil Pump per SOP-404A.

  ______/______
  Initials Date

- ENSURE MT Shaft Lift Oil Pump Suctions aligned for normal operation per SOP-404A, Section 5.3.4 (i.e. Section complete, 1-SC18S022, TURB SHFT LIFT OIL PMP 1-01 SUCT VLV is OPEN).

  ______/______
  Initials Date

3.0 PRECAUTIONS

3.1 Administrative

[C] 3.1.1 Thermal Power changes $\geq$15% of the Rated Thermal Power within a one hour period require an RCS isotopic analysis for iodine between 2 and 6 hours following the power change. Notification of Chemistry and Radiation Protection departments is required (TS SR 3.4.16.2, ODCM 4.11.2.1.1.2 and 4.11.2.1.1.3).

3.1.2 A plant vent grab sample shall be analyzed following shutdown, startup or a thermal power change $\geq$15% of rated thermal power within 1 hour, if analysis of the primary coolant shows dose equivalent I-131 concentration has increased by a factor of 3 or the noble gas monitor shows effluent activity has increased by a factor of 3 (ODCM 4.11.2.1.1.3).

3.1.3 Operations Management shall be notified if AFW discharge line temperature(s) exceed 250°F on the Main Control Board indicators.

3.1.4 Prior to opening the SG Atmospheric Relief Valves, Chemistry shall be notified to determine whether a release permit is required as stated in STA-603.

3.1.5 STA-735 describes the Fuel Integrity Program. This program includes additional Radiochemistry sampling requirements for Startup after fuel movement, Startup from the shutdown condition during a cycle, Shutdown, and Power condition. When I-131 values increase to more than 25% above the previous equilibrium value, sample frequency and data collection should be implemented per STA-735. When failed fuel is detected, the Failed Fuel Action Guidelines of STA-735 should be reviewed for applicability. These guidelines may place additional restrictions on power level or ramp rates.

3.1.6 IF main feedwater back leakage is indicated by abnormally high AFW pump discharge piping temperature, OR by high AFW temperature indication, THEN REFER to ABN-305.

3.1.7 Any time temperature through the upper penetration is >250°F, the time shall be LOGGED in the Unit Log. The maximum time allowable >250°F is 24 hours. Temperature should be RESTORED to less than 250°F within 24 hours. If temperature >250°F for 24 hours, System Engineering should be CONTACTED. Refer to ABN-302.

3.1.8 Reactor operation at low-power levels for extended periods of time is discouraged. Station management shall carefully consider the risk of operating during off-normal plant conditions such as low-power operation, develop appropriate contingencies, and provide training to operators before the evolution. Guidance should identify potential problems that could be encountered such as the possibility that the core may become subcritical and predefines conditions under which operators should shut down or manually scram the reactor.

3.2 Equipment

3.2.1 When changing RCS boron concentration, Pressurizer heaters and sprays should be utilized to minimize the differential between the Pressurizer and RCS loop boron concentrations to less than 50 ppm.

3.2.2 During Power Operations, boration or dilution is used to control temperature. Control Rods are used to control ΔI. Control Rods are normally in Auto at 100% power. Control Rods may be used in Manual if desired.

3.2.3 A Reactor Coolant Pump shall not be started while in MODE 2 or MODE 1 operation.

3.2.4 The Turbine Generator should be operated within the limits specified in TDM-401A and Back Pressure Limit Display between 105 MWe and 640 MWe (turbine power).

3.2.5 During normal operation, SG chemistry parameters shall be maintained within the limits specified in STA-610 and CHM-130.

3.2.6 During normal operation, RCS chemistry parameters shall be maintained within the limits specified in STA-609 and CHM-120.

3.2.7 Plant modifications such as changing the physical location of nuclear detectors or modifying existing nuclear detectors and changing the core loading pattern can affect Nuclear Instrumentation indication of Reactor power. N-16 Power should be used as an alternate indication of Reactor power level to verify the accuracy of nuclear instrumentation and power level indication during startup.

3.2.8 N-16 should be monitored as an indication of power along with NIS and Calorimetric power. N-16 may be the most accurate indicator of power during a transient since it is temperature compensated. During transient conditions, the highest indication of Reactor power (N-16, NIS, or Calorimetric) should always be maintained within limits.

3.2.9 Unless special testing is being conducted, the Main Turbine should not be operated for extended periods (>one hour) at 1800 RPM without being loaded. Uneven heating at no load conditions may result in excessive vibration and possible turbine damage.

3.2.10 The Main Turbine HP Stop Valves should not be opened during MSR prewarming. This will result in cross connecting the Main Steam and Auxiliary Steam headers.

3.2.11 The LP Turbine Monitoring System thermocouples are installed at 50% of the support arm wall thickness. The affects of operator initiated actions to reduce temperature will not be seen immediately.

3.2.12 Control Rods should NOT be placed in automatic until the fuel is fully conditioned to 100% power.

3.2.13 The ARVs should not be opened greater than 80% during normal operation. This is to prevent steam from entering the main steam penetration room thus increasing oxidation and moisture damage to components.

3.2.14 ARVs may be used for RCS Temperature Control without operational restrictions. (SMF 2000-001634)

3.2.15 Below 40% Power, Main Steamline N16 Radiation Monitors are not accurate and spurious alarms may occur.

3.2.16 If 5A/6A or 5B/6B heater string(s) isolate (automatic closure of 1-HV-2611A/B or 2612A/B) due to level perturbations during startup or shutdown, the affected heater(s) shall only be realigned after the heater string(s) have been filled and vented per SOP-303A. The Main Feedwater Pumps could trip if the heater string is not filled and vented prior to restoring condensate flow through the heaters.

3.2.17 Intermediate Range should be MONITORED AND/OR TRENDED to provide alternate indication of how power is trending. At low power, Power Range Instruments may not give an accurate trend of actual power.

3.2.18 Should the reactor become subcritical, PROCEED without delay to insert control rods, initiate boron addition, or open the reactor trip breakers to ensure the reactor remains shutdown.

3.2.19 Prior to energizing 1MT1/1MT2 displays “Vacuum Alarm”. This alarm is not unexpected and it should clear when the transformer warms up. When Vacuum Alarm is received while transformer is not energized, INITIATE Annunciator OOS with Comp Action to check alarm cleared after 1MT1/1MT2 energized (once per shift) per
ODA-410

4.0 LIMITATIONS/NOTES

4.1 Limitations

4.1.1 Power Range channels shall be operable per TS 3.3.1.2 and 3.3.1.3.

4.1.2 Axial Flux Difference shall be maintained within the values specified in NUC-204 per TS 3.2.3.

4.1.3 Control Banks shall be within the insertion, sequence and overlap limits specified in the COLR per TS 3.1.6.

4.1.4 IF any fuel conditioning ramp rate limit is violated,
THEN
Core Performance Engineering and the Director, Operations shall be NOTIFIED
AND
a Condition Report should be INITIATED per STA-421.

4.1.5 Core Performance Engineering should be CONTACTED to obtain the fuel conditioned power limitations per NUC-114:

- During initial startup of each fuel cycle, prior to exceeding 20% Rated Thermal Power
- After extended low-power operation (>27 days)

4.1.6 Unless otherwise determined by Core Performance Engineering, fuel conditioning ramp rates are as follows:

- No single step increase in power shall exceed 3% full Reactor power.
- The rate of Reactor power increase between 40% and 100% of full power should be $\leq$3% in an hour.

4.1.7 After Fuel Conditioning is satisfied as determined by Core Performance Engineering, Reactor power increases will be made at the rate recommended by Core Performance Engineering with concurrence from the Operations Director.

4.1.8 The rate of Reactor power increase should be administratively limited to <20% per hour when a more restrictive limit is not required (NUC-114).

4.1.9 When administrative control bank withdrawal limits are required to maintain a positive moderator temperature coefficient (MTC) within limits, rods shall be MAINTAINED below the withdrawal limits in NUC-116 per TS 3.1.3.

4.1.10 Four FWIVs, FCVs and associated bypass valves shall be OPERABLE per TS 3.7.3.

4.1.11 FWIV temperature should be VERIFIED $\geq$90°F at all times. If temperature is <90°F REFER to TRM 13.7.38.

4.1.12 Prior to increasing power above 50%, reasonable AFD stability needs to exist. Power should not be increased until AFD can be steadily maintained inside the operating limits. An administrative AFD limit of ±2% about the target value should be maintained during steady state operation. If AFD deviates outside this limit or if AFD oscillations occur, immediate operator action should be initiated to restore AFD within its administrative limit. This limitation may be modified by Core Performance Engineering based on core operating data.

4.1.13 Auxiliary Feedwater piping upstream of the auxiliary feedwater supply line check valves may reach temperatures of 270°F for short excursions (less than 24 hour duration per excursion) provided the Reactor is operating at or below 30% of Rated Thermal Power.

4.1.14 A Condition Report should be INITIATED for Reactor Engineering to re-evaluate the safety analysis if power operation is restricted to less than 85% for greater than 2 consecutive weeks.

4.1.15 The following limitations apply to the LP Turbine (These limitations do not preclude use of Steam Dumps prior to synchronizing the Generator):

- Limit ΔT to prevent the bottom of the LP Turbine support arms from being hotter than the top by more than 50°F.
- If ΔT reaches 60°F, actions should be initiated to restore temperature within 15 minutes. When ΔT can not be reduced to <60°F within 15 minutes, the generator should be synchronized <u>OR</u> the turbine stop and control valves should be closed within the following 15 minutes.
- When the turbine must be shutdown due to high ΔT, the main condenser should be allowed to cool down by reducing Reactor power and subsequent Steam Dump operation. Turbine generator restart should not be initiated until the generator can be synchronized quickly.

4.1.16 Fuel Conditioning requirements for Rod withdrawal Limitation are as follows:

- Control rod withdrawal during the initial return-to-power should be kept to a minimum to limit local power increases.
- The withdrawal rate should be limited to 3 steps per hour above 50% of full power where rod withdrawal may occur concurrently with power increases up to the 3% per hour.
- Once the control rods have been withdrawn to some position at a given power level, during subsequent maneuvers there is no restriction on rod withdrawal to the previous position up to that power level.
- There is no Rod withdrawal Limitation on Control Bank D above 215 steps.

4.1.17 Automatic start of the Motor Driven AFW Pumps on the trip of both Main Feedwater Pumps is required Operable in MODES 1 and 2 (TS 3.3.2, Table 3.3.2-1 Function 6.g) to ensure a supply of water to at least one SG for heat sink availability. In MODE 1 or 2 with one MFP supplying flow to the SGs (AFW pumps stopped), the second MFP must remain tripped or have the trip oil pressure switches isolated to ensure compliance with TS 3.3.2. (CR-2010-000638)

4.2 Notes

4.2.1 Constant load operations will be monitored per Section 5.5.

4.2.2 Steps within this procedure which address a specific Reactor power level value or range to be maintained, may require modification based on plant response. Provided the mode change checklist (Att 1) is complete and reviewed, the Shift Manager may direct Reactor power to be adjusted as necessary to ensure plant availability. Any deviation from the Reactor power level specified within this procedure shall be approved by the Shift Manager prior to the deviation.

4.2.3 Operational events which could affect fuel performance should be reported to Core Performance Engineering by initiation of a Technical Evaluation. Examples of such events include rapid RCS cooldowns or heatups, unusual control rod movements, unusual nuclear instrumentation (NIS) indications, etc.

4.2.4 Performance of this procedure for startup, shutdown or turbine overspeed trip testing is considered as an Infrequently Performed Evolution which should be implemented in accordance with OWI-107.

4.2.5 A systematic step-by-step review and implementation of the procedure instructions (steps, notes and cautions) is required to implement this IPO. The Bubble Chart on Attachment 17 gives guidance as to what sequence the IPO steps may be performed when increasing or decreasing power.

4.2.6 During implementation of this IPO, the SRO directing IPO activities is expected to **INITIAL AND DATE** steps once they have been performed, and notes and cautions once they have been evaluated for the applicable evolution.

Initialing the steps, notes and cautions provides a place-keeping aid to ensure the information has been reviewed and disseminated to the Shift Operations crew.

Providing a date for the steps, notes and cautions provides a time-frame with respect to when the instruction was completed, which may benefit planning an evolution that is being resumed following a time delay.

IPO steps reverified/reperformed following a delay where the step(s) had previously been signed off should be redated.

4.2.7 Any step which can not be performed in part or in its entirety due to equipment conditions, should be DOCUMENTED in the remarks section at the end of the procedure. The deviation shall not violate any Technical Specification limitation.

4.2.8 If desired to transition to another Integrated Plant Operating Procedure prior to completion of this procedure, the transition may be made, provided the Unit Supervisor and Shift Manager agree that the transition is appropriate.

4.2.9 Many graphs and tables formerly found in the TDM are now located in the cycle specific Nuclear Design Report (NDR).

4.2.10 Power Change Thumb rules (should NOT be used in place of an actual calculation, but may be used as a check to ensure calculations are reasonable).

- Power Defect 15 pcm/%
- Rod Worth 3 pcm/step
- Boron Worth 8 pcm/ppm
- Boration 10 gallons/ppm

4.2.11 When bringing on the second FWP, flow on the running FWP will be reduced by approximately ½. Running FWP flow should be $\geq$12000 gpm before attempting to forward flow the oncoming FWP. This ensures that both FWPs can be comfortably maintained above the recirc valve setpoint of 5000 gpm. The objective is to slowly increase oncoming FWP speed while closing down on its recirc valve. This is best accomplished by making a speed increase, followed by closing down on the recirc valve as far as possible without dipping below 5000 gpm on the oncoming FWP. As the oncoming FWP begins to forward flow, speed and flow for the running FWP will decrease (if in automatic). It is important to anticipate this decrease to prevent overshooting with the oncoming pump. Speed for the running FWP should be allowed to stabilize between adjustments. As speed and flow of the oncoming FWP approach that of the running FWP, it may be necessary to REDUCE oncoming FWP speed to maintain it at or below that of the running FWP. Once the recirc valve for the oncoming FWP is fully closed, the procedure will place its controller in automatic and prepare the oncoming FWP for automatic speed control.

4.2.12 An isotopic analysis for Iodine is required between 2 and 6 hours following a power change $\geq$15% within one hour.

4.2.13 If the Turbine Generator will be purged following shutdown, sufficient argon (three racks consisting of 16 bottles each) should be available for purge.

[C] 4.2.14 When activities which can directly affect core reactivity are performed (e.g., Control Rod positioning), conservative actions are needed and strict compliance with procedures must occur.

4.2.15 Attachment 14, Steam Dump Operation for Load Reject Testing provides guidance to allow use of the Steam Dumps to mitigate the affects of a Turbine Runback which may be performed to provide data to tune the Siemens Digital Control System or for Turbine Cooldown.

4.2.16 Attachment 16, If turbine operation at 1800 rpm will be extended for maintenance and testing, to reduce the consequences of extended Steam Dump operation, Reactor Power may be reduced to a level that will maintain Turbine speed and minimize Steam Dump operation. This could return the plant to MODE 2. When the turbine is ready to be synchronized to the Grid, power will be raised back to MODE 1. All requirements for MODE 1 operation should be maintained during MODE 2 operation to allow a timely return to MODE 1. Attachment 16 gives guidance to maintain MODE 2 and ensure a timely transition back to MODE 1.

4.2.17 Due to the location of the Temperature Probes on the MSR Tubesheets, the tubesheet temps on the MSR Display may have a difference of more than 15°F. Therefore, the MSR Tubesheet Temperatures on the EXP #2 MSR Temperatures Display may be used to determine deltaT.

4.2.18 The Low Pressure Turbine installed during 1RF10 may provide more extraction steam drain flow to the Heater Drain Tanks than the Heater Drain Pumps can forward flow. The inability of the Heater Drain Pumps to maintain Heater Drain Tank level will be indicated by the Heater Drain Pump discharge valve being full open or the Heater Drain Tank alternate drain valve opening. The Condensate Pump recirculation valve may be placed in manual and opened to redirect a portion of the Condensate Pump flow back to the condenser. This will reduce the pressure at the discharge of the Heater Drain Pumps and increase Heater Drain Pump flow. Feedwater Pump suction pressure should be closely monitored while throttling the Condensate Pump recirculation valve.

4.2.19 The Condensate Pump Recirc Controller has a toggle switch that serves to enable/disable the Trip to Auto feature. With the Switch in the "TRIP-TO-AUTO ENABLE" position the controller's Manual pushbutton will be illuminated and the Operator may adjust the valve as necessary. The controller will trip to Auto on a low flow condition ≤ 6000 gpm. When the controller trips to Auto the valve will go full open and the valve will stay at full open even when flow goes above the reset setpoint. When the valve trips to Auto the Auto pushbutton will illuminate. The Auto pushbutton is for indication only. After 5 seconds and Condensate flow is > 6000 gpm the Manual pushbutton may be depressed to restore Manual control. Manual control is indicated with the Auto pushbutton dark and the Manual pushbutton lit. Normal operation of 1-FK-2239 will be manual pushbutton lit with the toggle switch in "TRIP-TO-AUTO ENABLE", the Auto pushbutton will be dark. When the toggle switch is in the " TRIP-TO-AUTO DISABLE", the controller will function like any other controller in Manual with no automatic low flow pump protection. Anytime a Condensate Pump is operating, the toggle switch should be in "TRIP-TO-AUTO ENABLE".

4.2.20 Previous design of 1-FV-2239 was for the valve to open on a low flow condition ONLY when 1-FK-2239 was in AUTO. With the new LP Turbines, it may be desired to operate with 1-FV-2239 throttled open. This will reduce Condensate System pressure and allow more Heater Drain flow to the suction of the MFPs. To provide low flow protection for the Condensate Pumps with 1-FK-2239 throttled open at High Power levels, the toggle switch on 1-FK-2239 will be in "TRIP-TO-AUTO ENABLE". This will allow the controller to trip to auto on a low flow and provide Condensate Pump protection. A situation where the TRIP-TO-AUTO feature is desired would be when 1-FK-2239 is throttled to 30% open and a Rx Trip is initiated, the controller trips to Auto on a low flow and provides pump protection. There are also conditions in which this feature would not be desired. In those situations the toggle switch can be placed in the "TRIP-TO-AUTO DISABLE".

4.2.21 Due to increased secondary flow rates associated with 1RF13, extraction steam drain flow to the Heater Drain Tanks may be more than the Heater Drain Pumps can forward flow. The inability of the Heater Drain Pumps to maintain Heater Drain Tank level will be indicated by the Heater Drain Pump discharge valve being full open or the Heater Drain Tank alternate drain valve opening. The Condensate Pump recirculation valve may be placed in manual and opened to redirect a portion of the Condensate Pump flow back to the condenser. This will reduce the pressure at the discharge of the Heater Drain Pumps and increase Heater Drain Pump flow. Feedwater Pump suction pressure should be closely monitored while throttling the Condensate Pump recirculation valve.

4.2.22 A revision keyswitch for each channel of the turbine trip system is installed to allow maintenance tasks during turbine-generator outages while the turbine is at stand still or on turning gear. The keyswitch overrides any protection circuit trip signals. The actuation of the key is annunciate on the Turbine Digital Alarm Summary Display (Asd). By actuating the revision keyswitches all protection circuits are blocked. This should not be done in Modes 1, 2, and 3, see TRM 13.3.33.

- Overspeed protection system 1 will be reset and test frequency 2 (< max) is applied to simulate normal running speed (not tripped).
- A release signal is sent to the startup program (AGS1020) allowing stop and control valve operation.
- The manual turbine trip from main control board is blocked to prevent accidental actuation due to personnel safety reasons.
- The local manual trip remains operational allowing the turbine to be tripped locally if necessary.
- The trip block test also remains operational.

4.2.23 The following conditions apply if a positive Moderator Temperature Coefficient (MTC) exists:

- A positive MTC means that an RCS temperature INCREASE adds POSITIVE reactivity, AND an RCS temperature DECREASE adds NEGATIVE reactivity.
- A transient that causes a reduction of RCS temperature will cause a resulting decrease in core reactivity. The reduction in core reactivity will compound the RCS temperature reduction, which could result in a rapid or large reduction in RCS pressure and Pressurizer level.
- The primary plant should lead the secondary plant during Main Turbine load changes. Additional attention should be given to maintaining RCS temperature at or slightly above Tref (Tavg maintained higher than Tref) during power increases, as long as MTC is significantly positive.
- As power increases and RCS Boron Concentration decreases, MTC will decrease, eventually becoming negative by 100% RTP (as required by TS 3.1.3)
- The Turbine load rate value established to support the ramp rate should consider the RCS temperature band expectations so that adjustments to Turbine loading may be made prior to RCS Tavg being reduced below Tref.

4.2.24 For power changes greater than 5%, a reactivity plan should be DEVELOPED using one of the sources below.

- <u>IF</u> time and resources support generation of a BEACON projection (for a pre-planned power maneuver),
<u>THEN</u>
CONTACT Core Performance Engineering for support, <u>AND</u> UTILIZE the approved results as the reactivity plan.
- <u>IF</u> the power change closely matches one of the down-power scenarios available in the Reactivity Briefing Sheets (printed from CHORE),
<u>THEN</u>
UTILIZE the appropriate reactivity plan (interpolation between values on the Boration Matrix is allowed).
- <u>IF</u> the above two options are not available or do not fit the current scenario,
<u>THEN</u>
PERFORM a NDR based reactivity calculation per Attachment 3 or equivalent CHORE output.

4.2.25 Attachment 18 is available for use to adjusted Pressurizer spray valve bypass valves if temperature requires adjustment.

5.0 INSTRUCTIONS

5.1 **Warmup and Synchronization of the Turbine Generator**

CAUTION:
- The Main Turbine HP Stop Valves should not be opened during MSR prewarming. This will result in cross connecting the Main Steam and Auxiliary Steam headers.
- Time spent with the Main Turbine at 1800 RPM AND NOT synchronized to the grid should be minimized to prevent possible turbine damage. IF testing will be performed with the Main Turbine at 1800 RPM AND NOT loaded (e.g. Main Turbine Overspeed Test, Speed/Load Controller Tuning, etc.), briefing of these evolutions should be completed prior to rolling the Turbine to 1800 RPM and personnel should be readily available to perform the required test(s).

NOTE: Attachment 11 may be used to shutdown the reactor and re-enter MODE 3 when the Unit is operating in MODE 2 conditions.

5.1.1 ENSURE the prerequisites of Section 2.0 are met. _______/_______ Initials Date

5.1.2 PREPARE the LP Turbine and Control Fluid Pumps for startup.

A. ENSURE the EHC Pumps have been rotated within the last week in accordance with OWI-409. _______/_______ Initials Date

B. LP Turbine Monitoring System temperatures are being monitored and trended on the Plant Computer (Group Displays LPTDIFF, LPT1CASE and LPT2CASE). _______/_______ Initials Date

NOTE: The following steps are to preclude potential yoke damage as documented in CR-2012-003525 and CR-2012-004128.

B1. ENSURE the following valves are in AUTO:

- ☐ • 1-LK-2709, MSR A SEP DRN TK ALT LVL CTRL
- ☐ • 1-LK-2713, MSR B SEP DRN TK ALT LVL CTRL

_______/_______ Initials Date

B2. PLACE the following valves in MANUAL and CLOSED.

- ☐ • 1-LK-2712, MSR B SEP DRN TK NORM LVL CTRL
- ☐ • 1-LK-2708, MSR A SEP DRN TK NORM LVL CTRL

_______/_______ Initials Date

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-003A
POWER OPERATIONS	REVISION NO. 30 **CONTINUOUS USE**	PAGE 18 OF 226

CAUTION:

- The preferred methods to maintain Reactor power and temperature prior to synchronization are use of Steam Dumps and SG Blowdown Flow. Steam Dump operation and Main Steam Line Drain flow affect LP Turbine casing ΔT, which should be monitored prior to synchronization.
- If LP Turbine casing ΔT approaches limits prior to synchronization, a reduction in Steam Dump operation may be required, and Main Steam Line drain flow should also be limited.
- The preferred method, to reduce Steam Dump Operation and Main Steam Line drain flow, is maintaining maximum SG Blowdown flow.

NOTE:

- The LP Turbine Monitoring System thermocouples are installed at 50% of the support arm wall thickness. Operator initiated actions to reduce temperature will not be seen immediately. Vendor representatives may modify the following limits based on temperature trends during startup and operational performance.

5.1.2 C. MONITOR the LP Turbine Monitoring System temperatures until the generator is synchronized:

1) IF differential temperature approaches 50°F,
THEN
PERFORM the following actions to reduce temperature:

☐ • REDUCE steam dump operation.

☐ • REDUCE Main Steam line drain flow to the condenser.

☐ • ENSURE SG Blowdown flow is maximized.

☐ • SYNCHRONIZE the generator as soon as possible.

CAUTION: Exhaust hood spray valves should NOT be used as a method of differential temperature control when Turbine speed is less than rated speed (1800 rpm).

☐ • WHEN Turbine speed is approximately 1800 rpm,
THEN
CYCLE exhaust hood spray valves 1-HS-6556,
EXH HOOD SPR VLV and 1-HS-6555,
EXH HOOD SPR BYP VLV as necessary
to control differential temperature.

_______/_______
Initials Date

5.1.2 C. 2) IF differential temperature $\geq$60°F,
THEN
PERFORM the following:

- ☐ RESTORE differential temperature <60°F within 15 minutes.

OR

- ☐ Within the following 15 minutes, SYNCHRONIZE the generator

OR

- ☐ CLOSE the turbine stop and control valves.

_______/_______
Initials Date

D. Enter TR 13.3.33 to perform OPT-217A within 24 hours of turbine rollup. (RT 501762)

_______/_______
Initials Date

> NOTE: Drain valves are opened to drain moisture from the turbine during startup. The drains may be cycled as required to prevent excessive cooldown while startup is in progress.

5.1.3 OPEN the Turbine Drain Valves (1-CB-10).

- ☐ 1-HS-2418, HP CTRL VLV 3/4 AFT SEAT DRN VLV
- ☐ 1-HS-2419, TURB SIDE XOVER DRN VLV
- ☐ 1-HS-2420, MSR SIDE XOVER DRN VLV

Turbine Drain Valves OPEN

_______/_______
Initials Date

5.1.4 ENSURE OPT-410A has been completed within the previous 31 days. (TS SR 3.3.1.15.16a and 3.3.1.15.16b).

_______/_______
Initials Date

5.1.5 ENSURE Moisture Separator Reheater prewarming is completed per SOP-301A.

_______/_______
Initials Date

[C] 5.1.6 IF Reactor power will be increased by $\geq$15% within a one hour period,
THEN
NOTIFY Chemistry and Radiation Protection. (TS SR 3.4.16.2, ODCM 4.11.2.1.1.2, 4.11.2.1.1.3)

_______/_______
Initials Date

5.1.7 Prior to increasing Reactor power above 10%, PERFORM Flow Control and Isolation Valve Position verification per OPT-206A to ensure each AFW flow control valve and isolation valve is fully open (TS SR 3.7.5.1).

_______/_______
Initials Date

CAUTION: If 5A/6A or 5B/6B heater string(s) isolate (closure of 1-HV-2611A/B or 2612A/B) during subsequent steps, the affected heater shall only be realigned per Step 5.4.32. The Main Feedwater Pumps could trip if the heater string is not filled and vented prior to restoring condensate flow through the heaters

NOTE: Opening 1-HV-2611/12 to bypass 5 and 6 heaters will reduce secondary side transients by minimizing the effects of heater 5 and 6 isolation due to level oscillations commonly experienced in the heaters during Unit startup.

5.1.8 OPEN 1-HS-2611/12, FW HTR 5A & 6A/5B & 6B BYP VLV. ______/______ Initials Date

5.1.9 VERIFY the following annunciators are OFF:

- ☐ 1-ALB-9B, 3.9, EHC FLUID TEMP HI
- ☐ 1-ALB-9B, 5.6, TURB L/O TEMP HI

Annunciators are OFF ______/______ Initials Date

5.1.10 VERIFY lube oil temperature is >95°F on the TURB BRG TEMP RCDR 1 (1-SB10T010.G01 recorder point 12 on 1-CB-10). ______/______ Initials Date

5.1.11 OPEN 1-HS-2417, HP CTRL VLV 1●4 BEF SEAT DRN VLV (1-CB-10). ______/______ Initials Date

5.1.12 WHEN required by Chemistry,
THEN
TERMINATE Main Condenser sparging by closing 1-HS-2218, CNDSR HOTWELL AUX STM SPLY VLV (1-CB-09). ______/______ Initials Date

5.1.13 MONITOR the individual Auxiliary Feedwater discharge lines to each SG for indication of an excessive temperature increase during power escalation.

- 1-TI-2471A SG 1 MDAFW TEMP
- 1-TI-2471B SG 1 TDAFW TEMP
- 1-TI-2472A SG 2 MDAFW TEMP
- 1-TI-2472B SG 2 TDAFW TEMP
- 1-TI-2473A SG 3 MDAFW TEMP
- 1-TI-2473B SG 3 TDAFW TEMP
- 1-TI-2474A SG 4 MDAFW TEMP
- 1-TI-2474B SG 4 TDAFW TEMP

Monitoring AFW discharge lines ________/________
Initials Date

IF temperature increases,
THEN
INITIATE ABN-305 prior to exceeding 175°F: ________/________
Initials Date

5.1.14 PERFORM the following Pre-Turbine Roll Checks:

Turbine Display

A. VERIFY the Relative Expansion and Casing Differential Temperatures show no unexpected or sudden increases. ________/________
Initials Date

B. VERIFY the Relative and Differential Expansion and Casing Differential Temperature are less than allowable limits by verifying the following:

- ☐ • On the Turbine Display, DIFF and REL EXPANSIONs are Green.
- ☐ • 1-ALB-9B, 5.3, HP TURB CSG ΔT HI is not in Alarm. ________/________
Initials Date

TSE Margin Display

C. VERIFY Upper TSE Margin is available:

- ☐ • Upper Admission Bar Graph Green
- ☐ • TSE Influence ON ________/________
Initials Date

5.1.14 **Main Control Board**

D. ENSURE 1-TK-3091, EHC FLUID TEMP CTRL is set at 7.58 AND in AUTO.

_______/_______
Initials Date

E. ENSURE 1-TK-3094, TURB L/O TEMP CTRL is set at 6.08 AND in AUTO.

_______/_______
Initials Date

F. ENSURE the following controllers on the “Gen Temp/Leak Water” Display are in AUTO:

- ☐ In the “Primary Water TCV” Section Primary Water TEMP Controller (1-TV-3097) (Red)
- ☐ In the “Hydrogen TCV” Section Hydrogen TEMP Controller (1-TV-3118) (Red)

_______/_______
Initials Date

G. IF the LP casing (rotor) temperature on recorder 1-SB10T010.G01 point 11 (1-CB-10) <68°F prior to rolling the turbine,
THEN
MAINTAIN the turbine on the turning gear until temperature is >68°F. Refer to the Prewarming Curve for LP Discs in TDM-401A.

_______/_______
Initials Date

H. ENSURE the Turbine controls are ready for Start-up by performing the following:

“TG Control” Display

☐ 1) In the “Load Control” Section, ENSURE the Load Control Subloop Controller
is in Off (Green).

☐ 2) In the “Load Control” Section, ENSURE the Load Target Setpoint Controller
is set at 30 MW.

☐ 3) In the “Load Control” Section, ENSURE Load Rate Setpoint Controller is set at 100 MW/MIN.

☐ 4) In the “Speed Control” Section, ENSURE the Turbine is in Speed Control by verifying “Speed” Bar is Red.

_______/_______
Initials Date

5.1.15 PERFORM the following to ensure the turbine is reset:

A. IF the turbine is tripped (“Turbine Trip” Bar red), on the TG Control Display, THEN
RESET as follows:

1) ENSURE the Main Turbine HP Stop Valves are closed.

- ☐ • HPT STOP VLV 1 (SV1)
- ☐ • HPT STOP VLV 2 (SV2)
- ☐ • HPT STOP VLV 3 (SV3)
- ☐ • HPT STOP VLV 4 (SV4)

_______/_______
Initials Date

On the "TG Control" Display in the “Start-up” Section

2) VERIFY EH Converter position indicates CLOSED.

“Load Detail” Display

a) VERIFY EHC CH #1 OR EHC CH #2 at least NEGATIVE 80% OR more negative:

- ☐ • EHC CH #1

OR

- ☐ • EHC CH #2

☐ b) IF at least one converter is NOT at least NEGATIVE 80% OR more negative,
THEN
NOTIFY Prompt Team to investigate.

_______/_______
Initials Date

5.1.15 **"TG Overview" Display**

3) LATCH the turbine as follows:

☐ a) CLICK the Turbine Latch Subgroup Controller to bring up the "Osd"

☐ b) CLICK "0/1" then Execute to turn on the Controller.

NOTE: The Subgroup Controller should start to blink when the following step is complete. It will continue to blink until the Stop Valves are open.

☐ c) In the "Osd" CLICK "1" then Execute to start the latching of the turbine.

_______/_______
Initials Date

B. On the TG Control Display, VERIFY the turbine trip is reset ("Turbine Trip" Bar white).

_______/_______
Initials Date

5.1.15 C. VERIFY the following parameters:

Main Control Board

- ☐ 1-PI-6559, TURB L/O PRESS - >25 psig.
- ☐ 1-PI-6561, EHC FLUID PRESS - Minimum 114 psig.
- ☐ 1-PI-6566, HP EHC FLUID PRESS -Approximately 455 psig.

TG Overview Display

- ☐ HPT CTRL VLV 1 POSN - 0%
- ☐ HPT CTRL VLV 2 POSN - 0%
- ☐ HPT CTRL VLV 3 POSN - 0%
- ☐ HPT CTRL VLV 4 POSN - 0%
- ☐ HPT STOP VLV 1 - CLOSED
- ☐ HPT STOP VLV 2 - CLOSED
- ☐ HPT STOP VLV 3 - CLOSED
- ☐ HPT STOP VLV 4- CLOSED
- ☐ LPT 1 LP CTRL VLV 1 POSN - 0%
- ☐ LPT 1 LP CTRL VLV 2 POSN - 0%
- ☐ LPT 2 LP CTRL VLV 1 POSN - 0%
- ☐ LPT 2 LP CTRL VLV 2 POSN - 0%
- ☐ LPT 1 LP STOP VLV 1 - CLOSED
- ☐ LPT 1 LP STOP VLV 2 - CLOSED
- ☐ LPT 2 LP STOP VLV 1 - CLOSED
- ☐ LPT 2 LP STOP VLV 2 - CLOSED

________/________
Initials Date

NOTE:

- During operation at BOL with a zero or small negative moderator temperature coefficient, very little reactivity feedback will result from changes in temperature. During a startup significant temperature transients can occur with relatively little change to power. This could result in large transients in Pressurizer level and RCS pressure. Care should be taken to ensure changes in steam flow are done gradually to prevent transients in the RCS.
- Steam dumps in automatic should be used to raise power. Steam drains and blowdown are not the preferred method as Operator action is required to change the steam flow. Using Steam Dumps in automatic can reduce the transients in the primary systems since the automatic control will reduce steam dump flow as the turbine speed/load is increased.
- Nuclear Instrumentation may be conservatively calibrated following an extended outage period. Other indication of thermal power, such as calorimetric data, steam dump demand, etc., should also be monitored during the power increase. N-16 should be monitored as an indication of power along with NIS and Calorimetric power. N-16 may be the most accurate indicator of power during a transient since it is temperature compensated. During transient conditions, the highest indication of Reactor power (N-16, NIS, or Calorimetric) should always be maintained within limits.
- If 1-ALB-6D, 1.14 IR HI FLUX ROD STOP C-1 is received prior to 1-PCIP, 1.6 RX $\geq$10% PWR P-10, Core Performance Engineering and I&C should be notified to evaluate.

5.1.16 PERFORM the following steps to increase Reactor power to approximately 6% - 8% to provide additional steam flow capability:

A. IF desired,
THEN
ENSURE the FW BYP CTRL Controllers are in AUTO.

_______/_______
Initials Date

B. Prior to increasing Reactor power above 5%, ENSURE Attachment 1 has been completed and reviewed by the Shift Manager.

_______/_______
Initials Date

C. As Reactor power increases, VERIFY the Steam Dump System continues to maintain steam pressure at approximately 1092 psig.

_______/_______
Initials Date

5.1.16 **D. <u>WHEN</u> Reactor power is >5%, <u>THEN</u> LOG the time MODE 1 is entered:**

_______/_______/_______
Initials Date Time

E. PERFORM OPT-102A for MODE 1 surveillances now <u>AND</u> CONTINUE shiftly, as required.

_______/_______
Initials Date

F. Slowly INCREASE Reactor power to approximately 6% - 8%.

_______/_______
Initials Date

> <u>NOTE</u>: Update of MAXIMO MODE Status need not be completed prior to continuing this IPO, however programs triggered by MAXIMO may not be accurate until current MODE in MAXIMO is updated.

G. ENSURE MAXIMO indicates Unit 1 is in MODE 1.

_______/_______
Initials Date

> <u>CAUTION</u>: The following step should be performed just prior to rolling the Main Turbine. Should the turbine roll be delayed, MSR temperatures should be evaluated (<225°F) to determine if prewarming should be re-initiated prior to rolling the Main Turbine.

5.1.17 <u>WHEN</u> the turbine will be rolled,
<u>THEN</u>
PERFORM the following steps to secure Moisture Separator Reheater preheating:

A. On the “MSR” Display, CHECK the temperature difference between MSR 1A (MSRL) and 1B (MSRR) tubesheets $\leq$25°F.

_______/_______
Initials Date

B. <u>IF</u> the temperature difference is >25°F,
<u>THEN</u>
on the “MSR” Display in the MSR Setpoint Section, ADJUST <u>each</u> MSR HTG STM CTRL in Manual as necessary to achieve a tubesheet temperature difference $\leq$25°F for at least 10 minutes.

_______/_______
Initials Date

5.1.17 C. WHEN the temperature difference is ≤25°F for at least 10 minutes, THEN PERFORM the following:

> NOTE: The Reheater Drain Tank levels and MSR tube sheet temperatures should be closely monitored during subsequent steps. Leakage past the MSR temperature control valves or the Reheater Drain Tank level control valves will affect MSR tube sheet temperatures. The level control valves may be adjusted as necessary to maintain level and MSR temperature.

"MSR" Display

☐ 1) In the "MSR Prewarm" Section, ENSURE the Subgroup Controller is OFF (green/grey).

☐ 2) In the "MSR Setpoint" Section, ENSURE "Target" Setpoint Controller in MANUAL (Green).

☐ 3) In the "MSR Setpoint" Section, ENSURE BOTH MSR Heating Steam Controllers in MANUAL (Green) and set for 0%.

☐ 4) ENSURE both "MSR 1-A Demand" and "MSR 1-B Demand" at 0%.

5) ENSURE the following Temperature Valves go CLOSED:

- ☐ 1-TV-6580A, MSR A HTG STM CTRL VLV
- ☐ 1-TV-6580B, MSR A HTG STM CTRL VLV
- ☐ 1-TV-6580C, MSR A HTG STM CTRL VLV
- ☐ 1-TV-6581A, MSR B HTG STM CTRL VLV
- ☐ 1-TV-6581B, MSR B HTG STM CTRL VLV
- ☐ 1-TV-6581C, MSR B HTG STM CTRL VLV

6) CLOSE the Auxiliary Steam Supply Valves to each MSR:

- ☐ 1MS-0451, AUX STM SPLY TO MSR 1-A ISOL VLV
- ☐ 1MS-0454, AUX STM SPLY TO MSR 1-B ISOL VLV

5.1.17. C 7) On the MSR Display, ENSURE all MSR Heating Steam Equalization Valves CLOSED.

- ☐ • 1-HV-6583-1, MSL 1-02 TO MSR 1-A HTG STM EQUAL VLV
- ☐ • 1-HV-6583-2 MSL 1-03 TO MSR 1-A HTG STM EQUAL VLV
- ☐ • 1-HV-6583-3 MSL 1-01 TO MSR 1-B HTG STM EQUAL VLV
- ☐ • 1-HV-6583-4 MSL 1-04 TO MSR 1-B HTG STM EQUAL VLV

MSR Preheating is SECURED. ________/________
Initials Date

> NOTE: If at any time the HP Stop valves fail to open during the latching program, they may be opened manually per SOP-401A Section 5.3.3, Opening HP Stop Valves manually.

5.1.18 PERFORM the following steps to open the high pressure and low pressure stop valves:

☐ A. CLOSE 1-HS-2417, HP CTRL VLV 1●4 BEF SEAT DRN VLV (1-CB-10). ________/________
Initials Date

“EHC Detail” Display

B. VERIFY HP and LP Control Valves are CLOSED (0%)

HP

- ☐ • CV 1
- ☐ • CV 2
- ☐ • CV 3
- ☐ • CV 4

LP1

- ☐ • CV 1
- ☐ • CV 2

LP2

- ☐ • CV 1
- ☐ • CV 2

________/________
Initials Date

5.1.18 ☐ C. On the “TG Control” Display in the “Start-Up” Section, TURN ON the “Open Stop Valves” Subloop Controller.

_______/_______
Initials Date

D. On the TG Overview Display, VERIFY HP and LP Stop Valves are OPEN:

- ☐ • LPT 1 LP STOP VLV 1
- ☐ • LPT 2 LP STOP VLV 1
- ☐ • LPT 1 LP STOP VLV 2
- ☐ • LPT 2 LP STOP VLV 2
- ☐ • HPT STOP VLV 1 (SV1)
- ☐ • HPT STOP VLV 3 (SV3)
- ☐ • HPT STOP VLV 2 (SV2)
- ☐ • HPT STOP VLV 4 (SV4)

_______/_______
Initials Date

☐ E. OPEN 1-HS-2417, HP CTRL VLV 1.4 BEF SEAT DRN VLV (1-CB-10).

_______/_______
Initials Date

NOTE: Steam Dumps should be used when practical to maintain power. Increasing Reactor power to provide additional steam flow capability should not be performed until just prior to synchronization. Operation of the SG Atmospherics should NOT routinely be used to compensate for Steam Dump operation.

5.1.19 PERFORM the following steps to increase Main Turbine speed to 500 RPM:

A. IF temperature difference between MSR 1A (MSRL) and 1B (MSRR) tubesheets is >25°F,
THEN
PERFORM the following:

On the "TG Control" Display in the “Start-up” Section

1) UN-LATCH the Turbine as follows:

☐ a) CLICK the Turbine Latch Subgroup Controller to bring up the “Osd”

☐ b) CLICK “0/1" then Execute to turn on the Controller.

5.1.19 A.

> NOTE: The Subgroup Controller should start to blink when the following step is complete. When the turbine is Un-latched the Subgroup Controller will stop blinking.

☐ 2) In the “Osd” CLICK “0" then Execute to start the Un-Latching of the Turbine.

☐ 3) On the TG Control Display, VERIFY the turbine is tripped (“Turbine Trip” Bar red) AND Latch Bar is Green.

☐ 4) REFER to ALM-4000A, Digital Alarms, as necessary.

☐ 5) RETURN to Step 5.1.17.

______/______
Initials Date

B. MAINTAIN Reactor power at approximately 6% - 8% and Tavg approximately 557°F, while rolling the Main Turbine to 1800 rpm.

______/______
Initials Date

C. DISPATCH a Plant Equipment Operator to locally inspect the Main Turbine during roll up for any unusual noises, rubbing, etc.

______/______
Initials Date

> NOTE: The Main Turbine will begin rolling at a preset rate as soon as the “Speed Target” setpoint is above actual Turbine Speed.

D. On the “TG Control” Display in the “Speed Control” Section, ROLL the Main Turbine to approximately 500 RPM by raising the“Speed Target” Controller to 500 RPM.

______/______
Initials Date

5.1.19 E. On the “Lube Oil” Display, VERIFY “Turning Gear Valve # 1" closes at a Main Turbine speed of approximately 260 RPM.

_______/_______
Initials Date

F. VERIFY no unexpected or sudden increase in vibration is indicated:

- ☐ • Turbine Display or Turbine Vibration Display
- ☐ • Generator Display or Generator Vibration Display
- ☐ • Alarm Summary Display (Asd)

_______/_______
Initials Date

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NOTE:

- Thermal stress of the turbine shaft is calculated based on the differential temperature between the shaft surface and the internal shaft core temperature. Since the shaft is rotating, the use of an embedded thermocouple is impossible; therefore, a thermocouple measures the steam temperature entering the HP casing and this temperature is the shaft surface temperature. The shaft core temperature is then calculated from the inlet steam temperature by the TSE system.

- From these temperatures, the TSE system computes the upper and lower permissible temperature (Turbine) and Turbine Load Margins on the “TSE Margin” Display.

- The TSE, within the digital turbine control system, is constantly measuring temperatures at critical sections of the turbine and will limit the ramp up/ramp down as deemed necessary by internal stress calculations performed by TSE. If TSE determines that the allowable temperature margin is being approached or exceeded, alarm annunciation will occur and the ramp up/ ramp down will be limited. The following alarms may be received:

  TSE Lower Temp Margin <0
  TSE Lower Temp Margin <20
  TSE Upper Temp Margin <0
  TSE Upper Temp Margin <60
  TSE Lower Margin HP Shaft <0
  TSE Lower Margin HP Shaft <60
  TSE Upper Margin HP Shaft <0
  TSE Upper Margin HP Shaft <60

- While TSE Influence is off, any INCREASE in Turbine load is limited to 5 MW/min

- While TSE Influence is off, with a TSE fault present, the following limits apply:

  - Turbine speed should be held at warm-up speed (500 RPM) for a minimum of 20 minutes, prior to commencing ramp to 1800 RPM
  - Following initial synchronization, turbine load increases should be limited to a load rate of 2.27 MW/min while $\leq$ 400 MWe, THEN limited to 5 MW/min while greater than 400 MWe

G. On the “TSE Margin” Display, IF the Simulated Shaft Temperature is less than 120°F,
THEN
WAIT at least 20 minutes before increasing speed to 1800 rpm. ______/______
Initials Date

NOTE:

- The "Admission Temperature" Section on the "TSE Margin" Display shows the #1 Stop Valve which has a duplex thermocouple mounted in the valve that measures inner wall temperature (100%/steam side) and midwall temperature (50%).
- From these temperatures, the TSE calculates the permissible upper and lower temperature margins for the valves (Admission). To ensure the turbine startup rate does not exceed the thermal stress limits on the valves, the upper margin shall limit the speed controller's ramp rate.
- The TSE Margin Display has 2 Bar Graphs which have a positive and a negative temperature scale that represents Upper and Lower TSE Margins.

5.1.19 H. DETERMINE the upper TSE margin temperature limitations by monitoring the "TSE Margin" Display:

- IF the Admission Upper Margin is increasing or stable,
  THEN
  PROCEED to Next Step.

  _______/_______
  Initials Date

- IF the Admission Upper Margin is decreasing,
  THEN
  HOLD the Main Turbine Speed at 500 RPM until the Admission Upper Margin is increasing
  THEN
  PROCEED to Next Step.

  _______/_______
  Initials Date

- IF the Admission Upper Margin is approaching 0°F,
  THEN
  REDUCE Main Turbine speed as necessary until the Admission Upper Margin is increasing.
  WHEN the Admission Upper Margin is increasing,
  THEN
  INCREASE Main Turbine speed to 500 RPM
  AND
  PROCEED to Next Step.

  _______/_______
  Initials Date

5.1.20 IF an Overspeed Trip test is required (Prerequisite 2.20),
THEN
PERFORM the test per Attachment 4.

_______/_______
Initials Date

NOTE: 1-ALB-10A, 2.11, GEN CORE MONITOR ALARM may illuminate during Main Turbine speed increase to 1800 RPM. The annunciator should clear after the Generator Core Monitors are placed in service by the subsequent steps.

5.1.21 PERFORM the following steps to increase Main Turbine speed to 1800 RPM:

A. VERIFY no abnormal indications on the following Displays :

- Turbine Display
- Generator Display

_______/_______
Initials Date

NOTE: The TSE Margin Display has 2 Bar Graphs. Each of the 2 Bar Graphs has a positive and a negative temperature scale which represent Upper and Lower TSE Margins. At this point the upper bar graphs should be green and above 60°F.

5.1.21 B. VERIFY Upper TSE Margin is above 60°F and Upper Admission Bar is green on the "TSE Margin" Display.

_______/_______
Initials Date

NOTE:
- Hold Setpoint Function on the "TG" Display may be used at anytime during the Turbine Roll-up if problems occur.
- Initiating the Hold Setpoint Function will automatically reduce (ramp down) the turbine speed to 500 rpm. The turbine then remains at warm-up speed until the Operator resumes startup.

CAUTION: If the Upper TSE Margin stops the Main Turbine rollup prior to attaining at least 1765 RPM, Main Turbine speed should immediately be reduced to approximately 500 RPM to allow the Main Turbine to continue soaking.

C. In the "Speed Control" Section, ROLL the Main Turbine to 1800 RPM by raising the "Speed Target" Controller to 1800 RPM.

_______/_______
Initials Date

D. VERIFY Lube Oil Temperature is maintained at approximately 113°F as indicated on the TURB BRG TEMP RCDR 1 recorder (1-SB10T010.G01 recorder point 12 on 1-CB-10) while Main Turbine speed is increased.

_______/_______
Initials Date

5.1.21 E. PERFORM the following:

- VERIFY 1-HS-6579, TURB SHAFT LIFT OIL PMP automatically stops at a Main Turbine speed of approximately 540 RPM.
- PLACE 1-HS-6579 in AUTO AFTER STOP ________/________ Initials Date

F. WHEN turbine speed is approximately 1400 rpm,
THEN
ENSURE the EXCITER AIR DRIER and EXCITER HEATER in OFF at the Unit 1GENERATOR AUXILIARIES CABINET JC91 (TB 778, U1 GAC). ________/________ Initials Date

> NOTE: Past OE indicates that low lube oil pump discharge pressure may be caused by a stuck open check valve on one of the operating auxiliary lube oil pumps. Stopping the auxiliary oil pumps in this condition may cause a turbine trip. (CR-2015-011038)

G. VERIFY 1-PI-6558, TURB L/O PMP DISCH PRESS is between 155 and 175 psig. ________/________ Initials Date

H. WHEN Main Turbine speed increases above 1765 RPM,
THEN
STOP ALL running Auxiliary Oil Pumps AND PLACE in AUTO. ________/________ Initials Date

I. VERIFY no unexpected or sudden increase in vibration is indicated:

- ☐ Turbine Display or Turbine Vibration Display
- ☐ Generator Display or Generator Vibration Display
- ☐ Alarm Summary Display (Asd)

________/________ Initials Date

J. ENSURE the Generator Primary Water System startup steps which establish operating conditions at 1800 RPM have been completed per SOP-408A. ________/________ Initials Date

K. ENSURE the Generator Core Monitors are in service per SOP-405A. ________/________ Initials Date

L. IF shaft balance data is needed,
THEN
PERFORM the following:

1) ENSURE necessary data has been obtained. ________/________ Initials Date

2) IF a Main Turbine shutdown is required,
THEN
TRIP Main Turbine AND GO TO Attachment 4, Step 18. ________/________ Initials Date

3) IF the Main Turbine does NOT have to be shutdown,
THEN
PROCEED to the next step. ________/________ Initials Date

NOTE:
- 1-ALB-10A, 2.11, GEN CORE MONITOR ALARM may illuminate during Main Turbine speed increase to 1800 RPM. The annunciator should clear after the Generator Core Monitors are placed in service by the subsequent steps.
- Main Transformer cooling fans are placed in the required position prior to synchronizing the Main Generator to the grid (Step 5.1.27 C.).

5.1.22 ALIGN Unit 1 Main and Auxiliary Transformers for Startup as follows:

A. PERFORM the Preparing Unit 1 Main and Auxiliary Transformers for Unit Startup Section of SOP-601A. ________/________ Initials Date

5.1.23 DELETED

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NOTE:

- During operation at BOL with a zero or small negative moderator temperature coefficient, very little reactivity feedback will result from changes in temperature. During a startup significant temperature transients can occur with relatively little change to power. This could result in large transients in Pressurizer level and RCS pressure. Care should be taken to ensure changes in steam flow are done gradually to prevent transients in the RCS.

- Steam dumps in automatic should be used to raise power. Steam drains and blowdown are not the preferred method as Operator action is required to change the steam flow. Using Steam Dumps in automatic can reduce the transients in the primary systems since the automatic control will reduce steam dump flow as the turbine speed/load is increased.

- Nuclear Instrumentation may be conservatively calibrated following an extended outage period. Other indication of thermal power, such as calorimetric data, steam dump demand, etc., should also be monitored during the power increase. N-16 should be monitored as an indication of power along with NIS and Calorimetric power. N-16 may be the most accurate indicator of power during a transient since it is temperature compensated. During transient conditions, the highest indication of Reactor power (N-16, NIS, or Calorimetric) should always be maintained within limits.

5.1.24 SLOWLY INCREASE Reactor power to approximately 10% (6% - 10%) to provide additional steam flow capability.

_______ / _______
Initials Date

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CAUTION: U1 Generator should not remain connected to the Switchyard (8002 closed) >1 hour without closing a generator output breaker. The 1 hour limitation should prevent over-heating of the metering transformer windings.

5.1.25 PERFORM the following steps to prepare Unit 1 Generator for synchronization:

A. PERFORM Switching and Tagging Order per STA-617 using form STA-617-1 to connect the Main Generator.

_______/_______
Initials Date

NOTE: The following step enables input to 86-1/1G, 86-2/1G, deenergizes TEST SWITCH NOT RESET light inside 1-JD04.

B. PLACE the "Rotor Ground Protection Relay" Safety Switch -S5 (TVR Room, inside 1-JD04) in the "OPERATING" position.

_______/_______
Initials Date

C. CONTACT Meter and Relay to ensure the TVR is ready for Generator Start-up.

_______/_______
Initials Date

D. Following completion of Step A, PERFORM Switching and Tagging per STA-617 using form STA-617-21.

_______/_______
Initials Date

5.1.26 PERFORM the following steps to prepare the Main Generator for synchronization:

A. ENSURE SOP-408A, Section 5.1 is completed prior to loading the generator.

_______/_______
Initials Date

NOTE: The TSE Margin Display has 2 Bar Graphs. Each of the 2 Bar Graphs has a positive and a negative temperature scale which represent Upper and Lower TSE Margins. At this point the upper bar graphs should be green and above 60°F.

B. On the "TSE Margin" Display, VERIFY Upper TSE Margin is >0°F AND stable or increasing.

_______/_______
Initials Date

5.1.26 C. PERFORM the following steps to place the generator voltage regulator in service:

☐ 1) In the "Voltage Control" Section, ENSURE the ON/OFF Subloop Controller is in OFF (Green).

☐ 2) In the "Voltage Control" Section, ENSURE the Auto/Man Subloop Controller
in Auto (Red).

☐ 3) In the "Voltage Control" Section, VERIFY the Voltage Target Setpoint Controller is at approx. 22 KV.

> NOTE: The next step will excite the Main Generator and raise voltage to Approx.22 KV AND energize the Main and Unit Auxiliary transformers.

☐ 4) ENSURE personnel are clear of the Main Generator, and Main and Unit Auxiliary Transformers.

☐ 5) In the "Voltage Control" Section, PLACE the ON/OFF Subloop Controller in ON (Red).

☐ 6) On the "TG" Display, VERIFY Main Generator Voltage builds to Approx. 22 KV.

☐ 7) In the "Voltage Control" Section, VERIFY the Exciter Current Target is tracking with actual Exciter Current.

The Generator Voltage Regulator is in service ________/________
Initials Date

D. PREPARE the Turbine to go to Load Control upon synchronization:

☐ • In the "Load Control" Section, ENSURE the "Load Control" Subloop Controller is ON (Red).

☐ • In the "Load Control" Section, ENSURE the Load Target Setpoint Controller
is set at 30 MW.

☐ • In the "Load Control" Section, ENSURE Load Rate Setpoint Controller is set at 100 MW/MIN.

________/________
Initials Date

5.1.27 PERFORM the following steps to synchronize the main generator and initiate loading:

> NOTE:
> - Long periods of low power levels can cause turbine blade fatigue and excessive vibration.
> - Approximately 10% Reactor power on Steam Dumps corresponds to approximately 70 MWe with steam dumps closed.
> - Adjustment of TPCW flows to Hydrogen Coolers shortly after Sync may be necessary, experience has shown Hydrogen temperatures may reach near trip values.

A. NOTIFY QSE Generation Controller of approximate time for Main Generator synchronization.

_______/_______
Initials Date

B. Locally MONITOR 1-SS15T546, GEN PRIMARY WATER SYS LEAKAGE WTR CLR 1-544 OUT TEMP INDICATOR
AND
THROTTLE 1-SS15S558, GEN PRI WTR SYS LEAKAGE WTR CLR 1-544 TPCW OUT VLV as necessary to maintain approximately 104°F (40°C) on 1-SS15T546.

_______/_______
Initials Date

C. ENSURE the Main Transformer Cooling switches are in the required position locally:

1MT1

- ☐ 43T, Lead Select - LEAD NO 1
- ☐ 43F-1 (Cooler Group #1, Cooler 1 and 2) switch in MAN
- ☐ 43F-2, (Cooler Group #2, Cooler 3 and 4) switch in AUTO
- ☐ 43F-3, (Cooler Group #3, Cooler 5) switch in AUTO
- ☐ Reset and check “Failure Alarm Coolers Group” alarm clear

1MT2

- ☐ 43T, Lead Select - LEAD NO 1
- ☐ 43F-1 (Cooler Group #1, Cooler 1 and 2) switch in MAN
- ☐ 43F-2, (Cooler Group #2, Cooler 3 and 4) switch in AUTO
- ☐ 43F-3, (Cooler Group #3, Cooler 5) switch in AUTO
- ☐ Reset and check “Failure Alarm Coolers Group” alarm clear

Switches are aligned

_______/_______
Initials Date

5.1.27 D. VERIFY the following controllers on the “Gen Temp/Leak Water” Display are in AUTO:

☐ • In the “Primary Water TCV” Section Primary Water TEMP Controller (1-TV-3097) (Red)

☐ • In the “Hydrogen TCV” Section Hydrogen TEMP Controller (1-TV-3118) (Red)

Controllers are in Automatic. ________/________ Initials Date

E. MONITOR the GEN GROSS MW on the “TG” Display during the initial turbine synchronization and loading. ________/________ Initials Date

F. TURN the GEN BKR SYNCHROSCOPE for either generator output breaker 8000 or 8010 ON (SS-E3 or SS-W3). ________/________ Initials Date

G. In the “Voltage Control” Section, ADJUST Generator INCOMING VOLT (V-IN) to be 2V (one division) higher than RUNNING VOLT (V-RUN) using the Voltage Target Setpoint Controller ________/________ Initials Date

H. In the “Speed Control” Section, ADJUST main generator speed using the Speed Target Setpoint Controller to obtain a steady 2 - 4 RPM synchroscope rotation in the FAST direction. ________/________ Initials Date

CAUTION:
- During BOL picking up a large load on initial synchronization could induce large temperature transients in the RCS resulting in Pressurizer level and RCS pressure swings. Raising Reactor power using Steam Dumps in Automatic, then loading the Main Generator will allow the RCS to lead the secondary and provide a more controlled increase in power.
- Closing the Generator Output breaker will shift the Turbine Generator to Load Control and will ramp load to approx. 30 MW.

I. Just before the GEN BKR SYNCHROSCOPE pointer reaches the 12 o'clock position, CLOSE the selected output breaker and RECORD time:

- Breaker CLOSED.
- TIME:____________

________/________ Initials Date

5.1.27 J. VERIFY load rises to 30 MW at approximately 100 MW/min after output breaker closed.

_______/_______
Initials Date

> NOTE: Raising or Lowering Reactive Load (MVAR) on the Main Generator will affect reactive Load (MVAR) on the opposite Unit.

K. If required, In the "Voltage Control" Section, ADJUST reactive load by raising the
Voltage Target Setpoint Controller until a positive increase in MEGAVARS (out) on "TG" Display is observed.

_______/_______
Initials Date

L. COORDINATE with the opposite unit (if online) AND slowly ADJUST reactive load to balance MEGAVARS loading to maintain the desired 345 KV voltage by raising or lowering the Voltage Target Setpoint Controller in the "Voltage Control" Section.

_______/_______
Initials Date

M. If desired to raise or lower Turbine load to stabilize Rx Power, PERFORM the following:

1) SET the Load Rate Setpoint Controller to the desired Load Rate.

_______/_______
Initials Date

2) SET the Load Target Setpoint Controller to the desired Load.

_______/_______
Initials Date

N. TURN the GEN BKR SYNCHROSCOPE OFF.

_______/_______
Initials Date

O. TURN the GEN BKR SYNCHROSCOPE for the remaining output breaker ON.

_______/_______
Initials Date

P. VERIFY the pointer locks in at the 12 o'clock position.

_______/_______
Initials Date

Q. CLOSE the remaining open output breaker.

_______/_______
Initials Date

R. TURN the GEN BKR SYNCHROSCOPE OFF.

_______/_______
Initials Date

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CAUTION: The following steps will verify Main Generator Protection is available. The Computer points specified AND the SER alarm summary must be verified. Failure to verify these points as listed could result in operation without Generator protection.

5.1.27 S. To ensure Generator Protection is available AND the Load Reject relay is not picked up, OBTAIN an alarm summary from the SER AND VERIFY SER Alarm 98, GEN. OFF THE LINE-LOAD REJECTION PROTECTION, is not present in the current alarm summary.

_______/_______
Initials Date

NOTE: The following Plant Computer points indicate the status of the Generator output breakers and air switch inputs to Generator Protection circuitry.

T. VERIFY the following Plant Computer points indicate CLOSED:

☐ • Y0335D, GEN BRKR 8000 (Plant Computer) is CLOSED

☐ • Y0336D, GEN BRKR 8010 (Plant Computer) is CLOSED

_______/_______
Initials Date

5.1.28 NOTIFY QSE Generation Controller by updating GAPS for the change in “Unit Status” to “On-Line and Not Released (NR)” to show the time of main generator synchronization.

_______/_______
Initials Date

5.1.29 On the“TSE Margin” Display, VERIFY TSE allowance is >0 MW as indicated by the “Turbine Load Margin” (Upper)

_______/_______
Initials Date

5.1.30 On the Turbine Display, VERIFY the Relative Expansions and Casing Differential Temperatures show no unexpected or sudden increases as indicated.

_______/_______
Initials Date

5.1.31 VERIFY the Relative and Differential Expansion and Casing Differential Temperature are less than allowable limits by verifying the following:

☐ • Turbine Display, DIFF and REL EXPANSIONs are Green.

☐ • 1-ALB-9B, 5.3, HP TURB CSG ΔT HI is not in Alarm.

_______/_______
Initials Date

5.1.32 VERIFY no unexpected or sudden increase in vibration is indicated:

- ☐ • Turbine Display or Turbine Vibration Display
- ☐ • Generator Display or Generator Vibration Display
- ☐ • Alarm Summary Display (Asd)

No unexpected or sudden increase ______/______
Initials Date

5.1.33 PERFORM the following to align Extraction Steam to the heaters:

A. IF Extraction Steam Isolation valves to FW Heater 3A and 3B are caution tagged due to the drain valves being closed,
THEN
ENSURE caution tags are removed:

- ☐ • 1-HS-2031, FW HTR 3A ES SPLY VLV
- ☐ • 1-HS-2032, FW HTR 3B ES SPLY VLV ______/______
Initials Date

B. IF valves are closed,
THEN
slowly OPEN FW Heater 3A and 3B drain valves:

- ☐ • 1HD-0049, HTR DRN SYS FW HTR 1-3A OUT TO HTR DRN TK 1-3-2 ISOL VLV
- ☐ • 1HD-0114, HTR DRN SYS FW HTR 1-3B OUT TO HTR DRN TK 1-3-2 ISOL VLV ______/______
Initials Date

NOTE:
- The preferred method for establishing Extraction Steam is to align the low pressure feedwater heaters first and sequentially align the higher pressure feedwater heaters.
- Extraction Steam pressure may not be sufficient to allow alignment of all feedwater heaters at this time. Heaters should be aligned as Extraction Steam pressure increases which will allow the HI-HI level conditions to clear.
- Placing the Extraction Steam isolation valve handswitches in OPEN will clear the Turbine Trip and Feedwater Heater HI-HI level interlocks on the Feedwater Heater and Reheater Drain Tank normal drain valves. This will allow the normal drain valves to open in response to increasing level.

5.1.33 C. OPEN the Extraction Steam Isolation valves to the heaters:

- ☐ 1-HS-2033, FW HTR 4A ES SPLY VLV
- ☐ 1-HS-2034, FW HTR 4B ES SPLY VLV
- ☐ 1-HS-2031, FW HTR 3A ES SPLY VLV
- ☐ 1-HS-2032, FW HTR 3B ES SPLY VLV
- ☐ 1-HS-2029, FW HTR 2A ES SPLY VLV
- ☐ 1-HS-2030, FW HTR 2B ES SPLY VLV
- ☐ 1-HS-2027, FW HTR 1A ES SPLY VLV
- ☐ 1-HS-2028, FW HTR 1B ES SPLY VLV

_______/_______
Initials Date

NOTE: It may be necessary to repeat Steps 5.1.34 A through G if Reactor power is reduced below 10% on 3/4 Power Range channels.

5.1.34 <u>WHEN</u> Reactor power is above 10% (2/4 PR channels),
<u>THEN</u>
PERFORM the following:

A. VERIFY 1-PCIP, 1.6, RX $\geq$10% PWR P-10 is ON.

_______/_______
Initials Date

B. DEPRESS both Intermediate Range Manual Block pushbuttons:

- ☐ 1/1-N-38A, IR RX TRIP BLK
- ☐ 1/1-N-38B, IR RX TRIP BLK

_______/_______
Initials Date

5.1.34 C. VERIFY the following:

- ☐ • 1-PCIP, 1.2, IR TRN A RX TRIP BLK is ON.
- ☐ • 1-PCIP, 2.2, IR TRN B RX TRIP BLK is ON.

_______/_______
Initials Date

D. DEPRESS both Power Range Manual Block pushbuttons:

- ☐ • 1/1-N-47A, PR RX TRIP BLK
- ☐ • 1/1-N-47B, PR RX TRIP BLK

_______/_______
Initials Date

E. VERIFY the following:

- ☐ • 1-PCIP, 3.2, PR TRN A LO SETPT RX TRIP BLK is ON.
- ☐ • 1-PCIP, 4.2, PR TRN B LO SETPT RX TRIP BLK is ON.

_______/_______
Initials Date

F. VERIFY 1-ALB-6D, 1.1, SR HI VOLT FAIL is OFF.

_______/_______
Initials Date

G. VERIFY the following Trip Status Light bistables are ON:

- ☐ • 1-TSLB9, 1.8, RX$\geq$10% PWR NC-41M
- ☐ • 1-TSLB9, 2.8, RX$\geq$10% PWR NC-42M
- ☐ • 1-TSLB9, 3.8, RX$\geq$10% PWR NC-43M
- ☐ • 1-TSLB9, 4.8, RX$\geq$10% PWR NC-44M

_______/_______
Initials Date

H. PLACE <u>BOTH</u> HIGH FLUX AT SHUTDOWN block switches on the NIS Source Range Drawers in the NORMAL.

_______/_______
Initials Date

I. VERIFY 1-ALB-6D, 3.1, SR SHTDN FLUX ALM BLK is CLEAR.

_______/_______
Initials Date

5.1.35 <u>WHEN</u> the following are as indicated:

- 1-PCIP, 1.6, RX $\geq$10% PWR P-10 is ON

  <u>OR</u>

- 1-PCIP, 4.6, TURB $\leq$10% PWR P-13 is OFF,

<u>THEN</u>
ENSURE 1-PCIP, 3.5, RX & TURB $\leq$10% PWR P-7 is OFF.

_______/_______
Initials Date

5.1.36 PLACE the Main Feedwater Pump Westinghouse speed control in service as follows:

> NOTE:
> - The FWP DISCH HDR PRESS - MS HDR PRESS ΔP should be maintained, as necessary, to allow controlled feeding of the SGs. Higher ΔPs (near 80 psig) at low power may cause inadvertent feeding of the SGs due to leakage through the FCVs.
> - Plant Computer point U5002A, FW - MS HEADER DP provides indication of differential pressure between the FW Pump discharge header and the Main Steam header. Plant Computer point U5003A, DELTA PROGRAM - ACTUAL DP provides indication of the difference between the programmed differential pressure and actual differential pressure.

A. ENSURE Feedwater Pump turbine speed controllers are set per TDM-501A.

- ☐ 1-SK-509B FWPT A AUTO SPD CTRL
- ☐ 1-SK-509C FWPT B AUTO SPD CTRL

_______/_______
Initials Date

B. PLACE BOTH Main Feedwater Pump Auto Speed Controllers in AUTO:

- ☐ 1-SK-509B FWPT A AUTO SPD CTRL
- ☐ 1-SK-509C FWPT B AUTO SPD CTRL

_______/_______
Initials Date

C. Using the DFS display on the Plant Computer, slowly ADJUST 1-SK-509A, FWPT MASTER SPD CTRL to match the FWP FW REF value to the SPD CMD value for the selected FWP.

_______/_______
Initials Date

D. VERIFY applicable FWPT speed deviation indication (CB-08) is approximately zero.

- ☐ 1-SDI-2111D FWPT A SPD DEV
- ☐ 1-SDI-2112D FWPT B SPD DEV

_______/_______
Initials Date

E. DEPRESS the AUTO pushbutton for the selected MFP.

- ☐ 1-HS-2111B, FWPT A SPD CTRL MODE SELECT
- ☐ 1-HS-2112B, FWPT B SPD CTRL MODE SELECT

_______/_______
Initials Date

5.1.36 F. ADJUST Feedwater Pump speed with 1-SK-509A, FWPT MASTER SPD CTRL in MANUAL to maintain 1-PI-508, FWP DISCH HDR PRESS approximately 80 psig greater than 1-PI-507, MS HDR PRESS (Plant Computer point U5002A, FW - MS HEADER DP).

_______ / _______
Initials Date

G. VERIFY FWP SUCT FLOW AND FWP SUCT PRESS remain within normal bands.

_______ / _______
Initials Date

H. OPEN the FWIBV upstream manual isolation valves:

- ☐ 1FW-0209, SG 1-01 FW ISOL BYP VLV UPSTRM ISOL VLV
- ☐ 1FW-0211, SG 1-02 FW ISOL BYP VLV UPSTRM ISOL VLV
- ☐ 1FW-0213, SG 1-03 FW ISOL BYP VLV UPSTRM ISOL VLV
- ☐ 1FW-0207, SG 1-04 FW ISOL BYP VLV UPSTRM ISOL VLV

Isolation valves OPEN

_______ / _______
Initials Date

NOTE:
- SG levels should be continuously monitored while transferring control to the Feedwater Control Valves.
- Manipulation of the SG FW BYP CTRL valves and SG FW FLO CTRL valves should be performed on one feedline at a time.
- The SG FW FLO CTRL valves may be placed in manual as desired during startup.

5.1.37 PERFORM the following steps to place the SG FW FLO CTRL Valves in Automatic:

	1	2	3	4
A. ENSURE all SG FW FLO CTRL Valves are in MANUAL.	☐	☐	☐	☐
B. PLACE the selected SG FW BYP CTRL Valve in MANUAL.	☐	☐	☐	☐
C. Slowly OPEN the selected SG FW FLO CTRL valve until a feed flow increase is observed, THEN PLACE in AUTO.	☐	☐	☐	☐
D. Slowly CLOSE the selected SG FW BYP CTRL Valve in MANUAL.	☐	☐	☐	☐
E. REPEAT Steps 5.1.37 B thru D until all SG FW BYP CTRL Valves are CLOSED.	☐	☐	☐	☐

FCVs in Automatic ____________ / ____________
Initials Date

5.1.38 IF TPCW was opened OR Main Generator hydrogen Coolers need to be vented, THEN
VENT the Main Generator Hydrogen Coolers to ensure air is removed.

	OPEN	CLOSED
• 1TW-0159, MAIN GEN H2 CLR 1-505 TPCW VNT VLV	☐	☐
• 1TW-0115, MAIN GEN H2 CLR 1-501 TPCW VNT VLV	☐	☐
• 1TW-0117, MAIN GEN H2 CLR 1-508 TPCW VNT VLV	☐	☐
• 1TW-0120, MAIN GEN H2 CLR 1-504 TPCW VNT VLV	☐	☐
• 1TW-0122, MAIN GEN H2 CLR 1-503 TPCW VNT VLV	☐	☐
• 1TW-0125, MAIN GEN H2 CLR 1-507 TPCW VNT VLV	☐	☐
• 1TW-0127, MAIN GEN H2 CLR 1-502 TPCW VNT VLV	☐	☐
• 1TW-0130, MAIN GEN H2 CLR 1-506 TPCW VNT VLV	☐	☐

Venting complete ______ / ______
Initials Date

COMMENTS: ______________________________

5.2 **Establishing Turbine Load Control**

5.2.1 Closely MONITOR SG levels and maintain between 60% and 75%. ________/________
Initials Date

CAUTION:
- IF main feedwater back leakage is indicated by abnormally high AFW pump discharge piping temperature, OR by high AFW temperature indication, THEN refer to ABN-305.
- Any time temperature through the upper penetration is >250°F, the time shall be logged in the Unit Log. The maximum time allowable >250°F is 24 hours. Temperature should be restored to less than 250°F within 24 hours. If temperature >250°F for 24 hours, System Engineering should be contacted. Refer to ABN-302.

NOTE: It may be necessary to increase turbine load and extraction steam pressure to clear the HI-HI feedwater heater levels to maintain the extraction steam valves open. The valves should be opened as extraction steam pressure will allow the HI-HI level conditions to clear.

5.2.2 ENSURE the Extraction Steam Isolation Valves are OPEN:

- ☐ 1-HS-2033, FW HTR 4A ES SPLY VLV
- ☐ 1-HS-2034, FW HTR 4B ES SPLY VLV
- ☐ 1-HS-2031, FW HTR 3A ES SPLY VLV
- ☐ 1-HS-2032, FW HTR 3B ES SPLY VLV
- ☐ 1-HS-2029, FW HTR 2A ES SPLY VLV
- ☐ 1-HS-2030, FW HTR 2B ES SPLY VLV
- ☐ 1-HS-2027, FW HTR 1A ES SPLY VLV
- ☐ 1-HS-2028, FW HTR 1B ES SPLY VLV

________/________
Initials Date

5.2.3 ENSURE temperatures upstream of the AFW check valves are being monitored while performing subsequent steps.

☐ • T5288A, SG 1 UPPER NOZZLE TEMP

☐ • T5289A, SG 2 UPPER NOZZLE TEMP

☐ • T5290A, SG 3 UPPER NOZZLE TEMP

☐ • T5291A, SG 4 UPPER NOZZLE TEMP

_______/_______
Initials Date

[C] 5.2.4 IF Reactor power will be increased by ≥15% within a one hour period,
THEN
NOTIFY Chemistry and Radiation Protection.
(TS SR 3.4.16.2, ODCM 4.11.2.1.1.2, 4.11.2.1.1.3)

_______/_______
Initials Date

5.2.5 Increase Turbine power approx. 2% (10 to 20 MW) by PERFORMING the following:

On the “TG” Display in the “Load Control” Section

A. SET the Load Rate Setpoint Controller to the desired Load Rate. _______/_______
Initials Date

B SET the Load Target Setpoint Controller to the desired Load. _______/_______
Initials Date

C. Use manual Rod Control or RCS dilution or boration to MAINTAIN Tavg approximately equal to Tref.

_______/_______
Initials Date

5.2.6 MONITOR Axial Flux Difference (PR ΔFLUX) per NUC-204 as power is increased.

_______/_______
Initials Date

NOTE:	Control rod height should be adjusted as necessary to maintain AFD within the administrative limit of ±2% of the target value.

5.2.7 REFER to Attachment 2 for guidance in controlling AFD during power increases.

_______/_______
Initials Date

5.2.8 Increase the Turbine Load to approximately 170 MW (15%) by PERFORMING the following:

On the "TG" Display in the "Load Control" Section

A. SET the Load Rate Setpoint Controller to the desired Load Rate. ______/______ Initials Date

B. SET the Load Target Setpoint Controller to the desired Load. ______/______ Initials Date

> NOTE: Main Turbine operation between 105 MWe and 640 MWe requires higher Main Condenser values to prevent excessive LP turbine blades stresses. Operation with Condenser vacuum in the Not Permissible area is limited to ≤ 5 minutes per event and 300 minutes during total working life of the last blade row.

C. During power increase between 105 MWe and 640 MWe, MONITOR the Back Pressure Limit Display. ______/______ Initials Date

Back Pressure Limit Display

1) IF the cursor is in the NOT PERMISSIBLE Area,
THEN
TAKE one or more actions to reduce stresses on LP turbine blades as follows:

a) MAXIMIZE Condenser vacuum:

☐ • START all available CEVs.

☐ • START all available Circ Water Pumps.

☐ b) IF Condenser vacuum is still low,
THEN
REDUCE turbine load until vacuum is restored to within the PERMISSIBLE WITHOUT LIMIT area. (5 minutes or less) ______/______ Initials Date

5.2.9 Use manual Rod Control or RCS dilution as necessary to MAINTAIN Tavg approximately equal to Tref. ______/______ Initials Date

CAUTION: OPT-309 should be performed after reaching 15% power and prior to reaching 50% power and in all cases SHALL be performed within 24 hours after reaching 15% power.

NOTE: To ensure the accuracy of nuclear instrumentation, alternate indication of power level should be used to verify the validity of nuclear instruments and power level indications.

5.2.10 WHEN Reactor power ≥15%,
THEN
PERFORM the following:

A. COMPARE N-16 Power to indicated Reactor power. ________/________
Initials Date

CAUTION: Following a Refueling Outage or extended shutdown, Excore NI indications may be adjusted conservatively (higher than actual thermal power). When performing the calorimetric, care should be taken to ensure ACTUAL THERMAL POWER is 15% prior to adjusting power range or N-16 channels. Power range channels should not be adjusted such that P-10 is reset.

5.2.10 B. IF startup is being conducted following a Refueling Outage or an extended shutdown,
THEN
PERFORM the following:

- PERFORM a Primary Plant Performance (PPP) Calorimetric calculation per OPT-309 within 24 hours after reaching 15% power and prior to reaching 50% power.
(TS SR 3.3.1.2.2a, 3.3.1.2.6, and 3.3.1.2.7). ________/________
Initials Date

- IF Actual Thermal Power (based on the PPP calorimetric) ≥15%,
THEN
ADJUST NIS Power Range channels as required. ________/________
Initials Date

- IF Actual Thermal Power (based on the PPP calorimetric) ≥15%,
THEN
ADJUST N-16 Power Monitor channels as required ________/________
Initials Date

5.2.10 B.

- IF Actual Thermal Power (based on the PPP calorimetric) <15%,
  THEN
  RAISE Actual Thermal Power to approximately 15%
  THEN
  ADJUST NIS Power Range and N-16 Monitor channels as required. DO NOT adjust power range unless Actual Thermal Power is >10% RTP.

  ________/________
  Initials Date

- ENSURE the assumptions for power ascension from NUC-101 Attachment 3 have been reviewed prior to ramping to 30% Reactor power.

  ________/________
  Initials Date

- CONTACT Chemistry and ensure Secondary chemistry parameters are in specification for power escalation >15% per STA-610.

  ____________________ ________/________
  Chemist Contacted Name Initials Date

C. IF startup is NOT following a Refueling Outage or an extended shutdown,
THEN
PERFORM the following:

- ENSURE a Calorimetric calculation is performed per OPT-309 within 24 hours after reaching 15% and prior to reaching 50% power (TS SR 3.3.1.2.2a, 3.3.1.2.6, and 3.3.1.2.7).

  ________/________
  Initials Date

- CONTACT Chemistry and ensure Secondary chemistry parameters are in specification for power escalation >15% per STA-610.

  ____________________ ________/________
  Chemist Contacted Name Initials Date

5.2.11 WHEN Turbine load is approximately 170 MW (15%),
THEN
TRANSFER the Steam Dump System to the Tavg Mode, as follows:

☐ A. VERIFY ALL Steam Dump valves are CLOSED.

☐ B. PLACE 1-PK-507, STM DMP PRESS CTRL in MANUAL AND REDUCE demand to 0%.

☐ C. VERIFY 1-PCIP, 3.6, TAVE LO LO P-12 is OFF.

☐ D. PLACE 43/1-SD, STM DMP MODE SELECT to RESET THEN PLACE in TAVE.

☐ E. VERIFY 1-PCIP, 3.4, TURB LOAD REJ STM DMP ARMED C-7 is OFF.

☐ F. VERIFY ALL Steam Dump valves remain CLOSED.

☐ G. ENSURE 1-PK-507, STM DMP PRESS CTRL is set per TDM-501A.

Steam Dumps are in Tavg Mode. ________/________
Initials Date

NOTE:

- The FWP DISCH HDR PRESS - MS HDR PRESS ΔP should be maintained, as necessary, to allow controlled feeding of the SGs. Higher ΔPs (near 80 psig) at low power may cause inadvertent feeding of the SGs due to leakage through the FCVs.
- Plant Computer point U5002A, FW - MS HEADER DP provides indication of differential pressure between the FW Pump discharge header and the Main Steam header. Plant Computer point U5003A, DELTA PROGRAM - ACTUAL DP provides indication of the difference between the programmed differential pressure and actual differential pressure.
- Placing Main Feedwater Pump speed control in automatic prior to approximately 15% may affect feedwater pump speed control. Fluctuations of Turbine load while in Speed Control will cause variations in steam pressure and fluctuations in Condensate Pump discharge pressure will cause variations in feedwater pressure. Steam and feedwater pressure provide input into Main Feedwater Pump speed control. Fluctuations of these parameters at lower power levels have caused oscillations of feedwater pump speed while in automatic.

5.2.12 PLACE the Main Feedwater Pump speed control in AUTO as follows:

☐ A. ADJUST Feedwater Pump speed with 1-SK-509A, FWPT MASTER SPD CTRL to maintain 1-PI-508, FWP DISCH HDR PRESS approximately 80 psig greater than 1-PI-507, MS HDR PRESS (Plant Computer point U5002A, FW - MS HEADER DP).

☐ B. PLACE 1-SK-509A, FWPT MASTER SPD CTRL in AUTO AND VERIFY a differential pressure of approximately 80 psid maintained between 1-PI-508, FWP DISCH HDR PRESS and 1-PI-507, MS HDR PRESS (Plant Computer point U5002A, FW - MS HEADER DP).

☐ C. VERIFY FWP SUCT FLO AND FWP SUCT PRESS remain within normal bands.

Main Feedwater Pump Speed Control is in Automatic. ________/________

Initials Date

5.2.13 ENSURE the Feed Water Isolation Valves are OPEN:

☐ • 1-HS-2134, FWIV 1

☐ • 1-HS-2135, FWIV 2

☐ • 1-HS-2136, FWIV 3

☐ • 1-HS-2137, FWIV 4 ________/________

Initials Date

5.2.14 ENSURE the Feed Water Isolation Bypass Valves are CLOSED:

- ☐ • 1-HS-2185, FWIBV 1 ORC
- ☐ • 1-HS-2186, FWIBV 2 ORC
- ☐ • 1-HS-2187, FWIBV 3 ORC
- ☐ • 1-HS-2188, FWIBV 4 ORC

_______ / _______
Initials Date

COMMENTS:____

____

____

5.3 **Establishing 20% Turbine Load**

CAUTION:
- 20% Turbine load will be obtained with REACTOR POWER >20% due to inefficiencies at low power.
- Ramp rate limitations AND the POWER CHANGE LOG (OWI-104-55) SHALL be initiated prior to 20% REACTOR POWER (PPP Calorimetric or NIS).

NOTE: For power changes greater than 5%, a reactivity plan should be developed using one of the sources below.

- IF time and resources support generation of a BEACON projection (for a pre-planned power maneuver), THEN CONTACT Core Performance Engineering for support, AND UTILIZE the approved results as the reactivity plan.
- IF the power change closely matches one of the down-power scenarios available in the Reactivity Briefing Sheets (printed from CHORE), THEN UTILIZE the appropriate reactivity plan (interpolation between values on the Boration Matrix is allowed).
- IF the above two options are not available or do not fit the current scenario, THEN PERFORM a NDR based reactivity calculation per Attachment 3 or equivalent CHORE output.

[C] 5.3.1 IF Reactor power will be increased by $\geq$15% within a one hour period, THEN NOTIFY Chemistry and Radiation Protection. (TS SR 3.4.16.2, ODCM 4.11.2.1.1.2, 4.11.2.1.1.3)

_______ / _______
Initials Date

NOTE:
- Primary plant should lead secondary plant during Main Turbine load changes.
- During operation at BOL with a positive moderator temperature coefficient, a reduction in RCS temperature will result in negative reactivity being added to the core. REF Note 4.2.23. |
- For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the | reactivity plan. REF note 4.2.24 |

5.3.2 PERFORM the following steps to raise Turbine load to approximately 230 MW:

A. PRIOR to exceeding 20% Rated Thermal Power (indicated by PPP Calorimetric, NIS, or N-16), INITIATE the POWER CHANGE LOG (OWI-104-55) AND CONDUCT briefing for power ramp.

_______ / _______
Initials Date

5.3.2 B. IF desired,
THEN
CALCULATE the amount of dilution required to raise Reactor power to approximately 20% using the appropriate curves in the NDR
OR
OBTAIN boration/dilution calculations from Core Performance Engineering.

_______/_______
Initials Date

C. IF desired,
THEN
CALCULATE the rate of dilution required to allow slow control rod outward motion as the Turbine load increases, using the appropriate curves in the NDR
OR
OBTAIN boration/dilution calculations from Core Performance Engineering.

_______/_______
Initials Date

D. REFER to Attachment 2 for guidance in controlling AFD during power increases.

_______/_______
Initials Date

E. INITIATE RCS boration/dilution using SOP-104A.

_______/_______
Initials Date

F. In the “Load Control” Section, SET in the desired loading rate using the Load Rate Setpoint Controller

_______/_______
Initials Date

NOTE:
- The load will immediately begin increasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
- It may be necessary to raise Turbine Load in increments to maintain Ramp Rate Restrictions.

G. In the “Load Control” Section, RAISE the Load Target Setpoint Controller as necessary to obtain 230 MW while CONTROLLING the rate of turbine power increase.

_______/_______
Initials Date

5.3.3 TRANSFER the 6.9KV normal buses, from the Station Service Transformer 1ST to Unit 1 Auxiliary Transformer 1UT per SOP-603A.

_______/_______
Initials Date

CAUTION: Control Rods should NOT be placed in automatic until fuel conditioning requirements for Rod withdrawal Limitation are satisfied.

NOTE: To ensure NO demand for automatic rod motion, VERIFY the Circuit 1 output LED (outward motion) and the Circuit 2 output LED (inward motion) are OFF. Located in 1-RK-08, CF06, Card 41, labeled 1-SB-0412A and 1-SB-0412B.

5.3.4 IF desired,
THEN
PLACE the Control Rods in automatic as follows:

☐ A. VERIFY 1-PCIP, 2.4, LO TURB PWR ROD WITHDRWL BLK C-5 is OFF.

☐ B. WHEN Tavg is within 1°F of Tref and no automatic rod motion demand,
THEN
PLACE 1/1-RBSS, CONTROL ROD BANK SELECTOR in AUTO.

☐ C. IF necessary,
THEN
ADJUST control bank position by borating or diluting to maintain the Axial Flux difference within its administrative limit. (Reference NUC-204).

Control Rods are in Automatic.

_______/_______
Initials Date

5.3.5 CLOSE startup vents on 5 and 6 Feedwater Heaters/Drain Coolers per SOP-308A.

_______/_______
Initials Date

5.3.6 PERFORM the following steps to align the MSR steam to continue heating the MSR's:

A. On the "MSR" Display, MONITOR MSR tubesheet temperatures for a difference of < 25°F.

_______/_______
Initials Date

> NOTE: It may be necessary to manually open the MSR heating steam valves approximately 30 turns prior to operating the motor. This will allow a controlled warmup of the steam lines and prevent a motor trip on thermal overload.

5.3.6 B. IF the following valves are not open,
THEN
OPEN the valves manually OR on the MSR Display:

- ☐ • 1-HV-6583-1, MSL 1-02 TO MSR 1-A HTG STM EQUAL VLV
- ☐ • 1-HV-6583-2, MSL 1-03 TO MSR 1-A HTG STM EQUAL VLV
- ☐ • 1-HV-6583-3, MSL 1-01 TO MSR 1-B HTG STM EQUAL VLV
- ☐ • 1-HV-6583-4, MSL 1-04 TO MSR 1-B HTG STM EQUAL VLV

_______/_______
Initials Date

C. IF tubesheet temperatures ≤250°F AND MSR preheating was not complete prior to Turbine rollup,
THEN
PERFORM SOP-301A Section 5.3.3 to prewarm MSR's to 250°F.

_______/_______
Initials Date

D. When Prewarming of the MSRs are complete, CONTINUE to heat up MSRs to 600°F by PERFORMING the following:

1) ENSURE the individual MSR Heating Steam Controllers are in Auto (red)

_______/_______
Initials Date

> NOTE: The Setpoint Controller will drive the MSR Heating Steam Controllers to increase the Temperature of the MSR's to 600°F at 100°F/Hr.

2) ENSURE the "Target" Setpoint Controller in MANUAL (Green) and set for 600°F.

_______/_______
Initials Date

> NOTE: MSR pressure may be used as an indication that tubesheet temperature is being maintained approximately equal between the left and right MSRs. MSR pressure is the actual input to the MSR Heating Steam Controller, Tubesheet Temperature inputs to Alarms and Indication.

3) Closely MONITOR AND MAINTAIN tubesheet temperature difference < 25°F between the left and right MSRs.

_______/_______
Initials Date

NOTE: MSR Reheater Drain Tank pressure may be used as an indicator that the tubesheet temperature is being maintained approximately equal between the left and right MSRs. Pressure should be approximately equal on all four Reheater Drain Tanks during heatup.

5.3.6 E. VERIFY turbine and controller response:

- ☐ MSR Tube sheet temperature heatup rate < 100°F/hr (25°F/15 minutes)
- ☐ MSR 1-A and MSR 1-B tube sheet temperature difference ≤ 25°F.
- ☐ No unexpected or sudden increases in vibration as indicated on the Turbine Display.
- ☐ Hot Reheat steam pressures on 1-PR-2357/58 (Pts 5, 6) approximately equal between MSRs.
- ☐ Hot Reheat steam temperatures approximately equal on the Plant Computer:
  - T2601A, MSR B TO LP A TEMP
  - T2602A, MSR A TO LP A TEMP
  - T2603A, MSR A TO LP B TEMP
  - T2604A, MSR B TO LP B TEMP
- ☐ Heating steam control valves on the “MSR” Display are in agreement with the % output demand:

  0 - 50% (1-TV-6580A / 1-TV-6581A)

  50 - 75% (1-TV-6580B / 1-TV-6581B)

  75 - 100% (1-TV-6580C / 1-TV-6581C)

  _______/_______
  Initials Date

F. CLOSE 1-HS-6586, MSR HTG STM LN DRN VLV (1-CB-10). _______/_______
Initials Date

5.3.6 G. MONITOR the following parameters on the Plant Computer or trend recorder as Turbine load is increased to detect any temperature mismatch between MSR A and MSR B supply to the LP Turbines.

- ☐ • T2601A, MSR B TO LP A TEMP
- ☐ • T2602A, MSR A TO LP A TEMP
- ☐ • T2603A, MSR A TO LP B TEMP
- ☐ • T2604A, MSR B TO LP B TEMP

_______/_______
Initials Date

H. IF necessary,
THEN
OPEN extraction steam isolation valves to 1A/1B Feedwater heaters:

- ☐ • 1-HS-2027, FW HTR 1A ES SPLY VLV
- ☐ • 1-HS-2028, FW HTR 1B ES SPLY VLV

_______/_______
Initials Date

I. WHEN all the control valves are fully OPEN,
THEN
PERFORM Step 5.4.34 to fully pressurize the MSRs:

- ☐ • 1-TV-6580A, MSR A HTG STM CTRL VLV
- ☐ • 1-TV-6580B, MSR A HTG STM CTRL VLV
- ☐ • 1-TV-6580C, MSR A HTG STM CTRL VLV
- ☐ • 1-TV-6581A, MSR B HTG STM CTRL VLV
- ☐ • 1-TV-6581B, MSR B HTG STM CTRL VLV
- ☐ • 1-TV-6581C, MSR B HTG STM CTRL VLV

_______/_______
Initials Date

CAUTION:
- IF main feedwater back leakage is indicated by abnormally high AFW pump discharge piping temperature, OR by high AFW temperature indication, THEN refer to ABN-305.
- Any time temperature through the upper penetration is >250°F, the time shall be logged in the Unit Log. The maximum time allowable >250°F is 24 hours. Temperature should be restored to less than 250°F within 24 hours. If temperature >250°F for 24 hours, System Engineering should be contacted. Refer to ABN-302.

5.3.7 ENSURE temperatures upstream of the AFW check valves are continuing to be monitored.

- ☐ • T5288A, SG 1 UPPER NOZZLE TEMP
- ☐ • T5289A, SG 2 UPPER NOZZLE TEMP
- ☐ • T5290A, SG 3 UPPER NOZZLE TEMP
- ☐ • T5291A, SG 4 UPPER NOZZLE TEMP

________ / ________
Initials Date

COMMENTS: ____

5.4 **Establishing 100% Turbine Load**

> NOTE: During operation at BOL with a positive moderator temperature coefficient, a reduction in RCS temperature will result in negative reactivity being added to the core. REF Note 4.2.23

> NOTE: For power changes greater than 5%, a reactivity plan should be developed using one of the sources below.
>
> - IF time and resources support generation of a BEACON projection (for a pre-planned power maneuver), THEN CONTACT Core Performance Engineering for support, and utilize the approved results as the reactivity plan.
> - IF the power change closely matches one of the down-power scenarios available in the Reactivity Briefing Sheets (printed from CHORE), THEN UTILIZE the appropriate reactivity plan (interpolation between values on the Boration Matrix is allowed).
> - IF the above two options are not available or do not fit the current scenario, THEN PERFORM a NDR based reactivity calculation per Attachment 3 or equivalent CHORE output.

5.4.1 CONTACT Chemistry to check SG and Secondary Chemistry parameters and any Impact to the CEI (Chemistry Effectiveness Indicator).

______________________ Name of Chemist Contacted

_____ / _____ Initials Date

5.4.2 NOTIFY QSE Generation Controller of intent to increase turbine load.

_____ / _____ Initials Date

5.4.3 VERIFY the following:

- ☐ 1-PCIP, 1.2, IR TRN A RX TRIP BLK is ON.
- ☐ 1-PCIP, 2.2, IR TRN B RX TRIP BLK is ON.
- ☐ 1-PCIP, 3.2, PR TRN A LO SETPT RX TRIP BLK is ON.
- ☐ 1-PCIP, 4.2, PR TRN B LO SETPT RX TRIP BLK is ON.

_____ / _____ Initials Date

[C] 5.4.4 IF Reactor power will be increased by $\geq$15% within a one hour period, THEN NOTIFY Chemistry and Radiation Protection. (TS SR 3.4.16.2, ODCM 4.11.2.1.1.2, 4.11.2.1.1.3)

_____ / _____ Initials Date

CAUTION: Observe fuel conditioning limits during all Reactor power increases.

5.4.5 PERFORM the following to raise turbine load to approximately 350 MW (30%):

NOTE:
- To ensure the accuracy of nuclear instrumentation, alternate indication of power level should be used to verify the validity of nuclear instruments and power level indications.
- For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the reactivity plan. REF note 4.2.24

A. COMPARE N-16 Power to indicated Reactor power.

_______/_______
Initials Date

B. IF desired, THEN CALCULATE the amount of dilution required to raise Reactor Power to approximately 30% using the appropriate curves in the NDR OR OBTAIN boration/dilution calculations from Core Performance Engineering.

_______/_______
Initials Date

C. IF desired, THEN CALCULATE the rate of dilution required to allow slow control rod outward motion at the Turbine load increases, using the appropriate curves in the NDR OR OBTAIN boration/dilution calculations from Core Performance Engineering.

_______/_______
Initials Date

D. REFER to Attachment 2 for guidance in controlling AFD during power increases.

_______/_______
Initials Date

E. INITIATE RCS boration/dilution using SOP-104A.

_______/_______
Initials Date

F. In the "Load Control" Section, SET in the desired loading rate using the Load Rate Setpoint Controller.

_______/_______
Initials Date

NOTE:
- The load will immediately begin increasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
- It may be necessary to raise Turbine Load in increments to maintain Ramp Rate Restrictions.

5.4.5 G. In the "Load Control" Section, RAISE the Load Target Setpoint Controller as necessary to obtain 350 MW while controlling the rate of Turbine power increase.

_______ / _______
Initials Date

5.4.6 WHEN Reactor power is above 25%,
THEN
VERIFY the following:

- ☐ 1-TSLB-6, 1.2, IR FLUX HI NC-35F is ON
- ☐ 1-TSLB-6, 2.2, IR FLUX HI NC-36F is ON
- ☐ 1-TSLB-6, 1.6, PR FLUX SETPT LO NC-41P is ON
- ☐ 1-TSLB-6, 2.6, PR FLUX SETPT LO NC-42P is ON
- ☐ 1-TSLB-6, 3.6, PR FLUX SETPT LO NC-43P is ON
- ☐ 1-TSLB-6, 4.6, PR FLUX SETPT LO NC-44P is ON

_______ / _______
Initials Date

NOTE:
- 1-HV-2419A-D and 1-HV-2420A-D open automatically on turbine trip.
- Expect an increase in steam pressure and reactivity change when closing valves.

5.4.7 CLOSE the following Main Turbine drain valves (1-CB-10):

- ☐ 1-HS-2417, HP CTRL VLV 1●4 BEF SEAT DRN VLV
- ☐ 1-HS-2418, HP CTRL VLV 3/4 AFT SEAT DRN VLV
- ☐ 1-HS-2419, TURB SIDE XOVER DRN VLV
- ☐ 1-HS-2420, MSR SIDE XOVER DRN VLV

_______ / _______
Initials Date

5.4.8 ENSURE the Main Steam line drain valves are CLOSED (1-CB-08):

- ☐ • 1-HS-2432/5, MSL STRN D/POT VLV
- ☐ • 1-HS-2349, MSL 1 AFT MSIV D/POT VLV
- ☐ • 1-HS-2350, MSL 2 AFT MSIV D/POT VLV
- ☐ • 1-HS-2351, MSL 3 AFT MSIV D/POT VLV
- ☐ • 1-HS-2352, MSL 4 AFT MSIV D/POT VLV
- ☐ • 1-HS-2371, MSL 1 BEF MSIV D/POT DRN VLV
- ☐ • 1-HS-2372, MSL 2 BEF MSIV D/POT DRN VLV
- ☐ • 1-HS-2373, MSL 3 BEF MSIV D/POT DRN VLV
- ☐ • 1-HS-2374, MSL 4 BEF MSIV D/POT DRN VLV
- ☐ • 1-HS-2376, STM DMP HDR D/POT VLV
- ☐ • 1-HS-2375, MS HDR D/POT VLV
- ☐ • 1-HS-2378, FWPT HP HDR/FWPT A HP D/POT VLV
- ☐ • 1-HS-2377, FWPT B HP D/POT VLV

______/______
Initials Date

5.4.9 CLOSE the Extraction Steam drain valves (1-CB-10).

- ☐ • 1-HS-2011, FW HTR 1A ES SPLY D/POT VLV
- ☐ • 1-HS-2013, FW HTR 1B ES SPLY D/POT VLV
- ☐ • 1-HS-2015, FW HTR 2A ES SPLY D/POT VLV
- ☐ • 1-HS-2017, FW HTR 2B ES SPLY D/POT VLV
- ☐ • 1-HS-2019, FW HTR 3A ES SPLY D/POT VLV
- ☐ • 1-HS-2021, FW HTR 3B ES SPLY D/POT VLV
- ☐ • 1-HS-2023, FW HTR 4A ES SPLY D/POT VLV
- ☐ • 1-HS-2025, FW HTR 4B ES SPLY D/POT VLV

______/______
Initials Date

NOTE: IF HDPs will be running on recirc for >24hrs, THEN Plant Reliability should assess pump vibration (Reference EV-CR-2013-007250).

5.4.10 PERFORM the following to align the Heater Drain Pumps:

A. START both Heater Drain Pumps per SOP-308A.

_______/_______
Initials Date

B. WHEN authorized by Chemistry,
THEN
ALIGN Heater Drains for forward flow per SOP-308A.

_______/_______
Initials Date

NOTE: Operator experience has shown that the check vlv upstream of the separator drain tank normal control vlv may require several hours to open and may initially allow a large “slug” of colder water to pass through, possibility resulting in a secondary plant perturbation. Based on this knowledge it is expected that the MSR SEP DRN TK NORM LVL CTRL vlv’s will NOT be opened greater than 20% until flow is established from the separator drain tank. REF: CR-2012-12251

C. WHEN forward flow is established, THEN PERFORM the following:

Slowly OPEN the MSR SEP DRN TK NORM LVL CTRL vlvs to approximately 20% open in 4 equal steps of approximately 5% with a 30 second delay between each step.

- ☐ 1-LK-2712, MSR B SEP DRN TK NORM LVL CTRL
- ☐ 1-LK-2708, MSR A SEP DRN TK NORM LVL CTRL

D. CONTINUALLY MONITOR the MSR SEP DRN TK ALT LVL CTRL’s deviation meter for indications of closure.

- ☐ 1-LK-2713, MSR B SEP DRN TK ALT LVL CTRL
- ☐ 1-LK-2709, MSR A SEP DRN TK ALT LVL CTRL

_______/_______
Initials Date

5.4.10 E. When flow from the separator drain tank is established through the normal level controller,
THEN
PERFORM the following:

1) ZERO the controller deviation and PLACE the MSR SEP DRN TK NORM LVL CTRL vlvs in AUTO

2) ENSURE level is maintained:

☐ • 1-LK-2712, MSR B SEP DRN TK NORM LVL CTRL

☐ • 1-LK-2708, MSR A SEP DRN TK NORM LVL CTRL

F. IF after approximately 12 hours the Alt level control vlvs are not indicating less demand (indicating flow through the normal line)
THEN
PERFORM step 5.4.11.

______/______
Initials Date

5.4.11 IF normal drain flow from the Separator Drain Tank can not be established,
THEN
PERFORM Attachment 7 WHILE CONTINUING with this procedure.

______/______
Initials Date

5.4.12 COMPARE N-16 Power to indicated Reactor power.

______/______
Initials Date

5.4.13 ENSURE 1-HV-3228, U1 MS to AUX STM SPLY VLV is OPEN.

______/______
Initials Date

NOTE:

- Starting the second Condensate Pump at higher power levels may result in a more pronounced FWP suction pressure drop as the Condensate Pump discharge valve opens in preparation for pump start. The drop in FWP suction pressure is caused as flow from the running Condensate pump seats the discharge check valve of the pump being started. Experience has shown that starting a second Condensate Pump at 43% power could cause a momentary drop in FWP suction pressure of approximately 70 psig.
- Attachment 12 provides instructions for a condition where only one Condensate Pump is available for operation.
- For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the reactivity plan. REF note 4.2.24

5.4.14 IF not previously done,
THEN
START the second Condensate Pump per SOP-303A.

_______/_______
Initials Date

5.4.15 PERFORM the following to raise Turbine load to approximately 600 MW (50%):

☐ A. COMPARE N-16 Power to indicated Reactor power.

_______/_______
Initials Date

☐ B. IF the startup is following a Refueling Outage,
THEN
ENSURE the assumptions for power ascension from NUC-101 Attachment 4 have been reviewed prior to ramping to 80% Reactor power.

_______/_______
Initials Date

☐ C. IF desired,
THEN
CALCULATE the amount of dilution required to raise Reactor power to approximately 50% using the appropriate curves in the NDR
OR
OBTAIN boration /dilution calculations from Core Performance Engineering.

_______/_______
Initials Date

☐ D. IF desired,
THEN
CALCULATE the rate of dilution required to allow slow control rod outward motion as the Turbine load increases, using the appropriate curves in the NDR (Nuclear Design Report)
OR
OBTAIN boration /dilution calculations from Core Performance Engineering.

_______/_______
Initials Date

5.4.15

☐ E. REFER to Attachment 2 for guidance in controlling AFD during power increases.

_______/_______
Initials Date

☐ F. INITIATE RCS boration/dilution using SOP-104A.

_______/_______
Initials Date

NOTE: Primary plant should lead secondary plant during Main Turbine load changes.

☐ G. In the "Load Control" Section, SET in the desired loading rate using the Load Rate Setpoint Controller.

_______/_______
Initials Date

NOTE:
- The load will immediately begin increasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
- It may be necessary to raise Turbine Load in increments to maintain Ramp Rate Restrictions.
- During operation at BOL with a positive moderator temperature coefficient, a reduction in RCS temperature will result in negative reactivity being added to the core. REF Note 4.2.23

☐ H. In the "Load Control" Section, RAISE the Load Target Setpoint Controller as necessary to obtain 600 MW while controlling the rate of turbine power increase.

_______/_______
Initials Date

NOTE: When the Condensate Pump Recirculation Valve is closed, total discharge flow will decrease. If flow decreases below 6,000 gpm, the recirc valve will open and this step will need to be repeated when discharge flow is higher.

5.4.16 IF 1-ZL-2239, CNDS PMP RECIRC VLV is OPEN, THEN PERFORM the following:

☐ A. VERIFY 1-FI-2239, CNDS PUMP DISCH HDR FLO is >8,000 gpm.

☐ B. ENSURE 1-FK-2239, CNDS PMP RECIRC CTRL is in MANUAL.

☐ C. ENSURE 1-FK-2239 toggle switch is in TRIP-TO-AUTO ENABLE.

☐ D. Slowly CLOSE 1-FK-2239, CNDS PMP RECIRC CTRL.

☐ E. VERIFY 1-ZL-2239, CNDS PMP RECIRC VLV remains CLOSED.

_______/_______
Initials Date

NOTE:
- Only one Main Feedwater Pump is normally operated when a single Condensate Pump is available for operation. Attachment 12 provides instructions for a condition where only one Condensate Pump is available for operation.
- To reduce the likelihood of water hammer in the 3A and 3B heaters, it is preferable to wait until Heater Drain System forward flow is established before starting the second Main Feedwater Pump. This approach will take advantage of greater stability in the Heater Drain System and provide more time to thoroughly warm extraction steam lines.

5.4.17 START the second Main Feedwater Pump per SOP-302A.

_______/_______
Initials Date

NOTE: Running FWP suction flow should be greater than or equal to 12000 gpm before attempting to forward flow the oncoming FWP. This ensures that both FWPs can be comfortably maintained above the recirc valve setpoint of 5000 gpm. As the oncoming FWPs speed (and discharge pressure) approach that of the running pump, closing the recirc valve or increasing speed on the oncoming FWP will increase forward flow and cause running FWP speed and flow to decrease Refer to the amplified explanation in Step 4.2.11.

5.4.18 PERFORM the following to place the FWPT speed controls in AUTO:

A. VERIFY the following controllers are in AUTO:

- ☐ 1-SK-509A, FWP MASTER SPEED CTRL
- ☐ 1-SK-509B, FWPT A AUTO SPD CTRL
- ☐ 1-SK-509C, FWPT B AUTO SPD CTRL

_______/_______
Initials Date

B. PLACE the oncoming FWP recirculation valve in MANUAL AND OPEN it as required to obtain 5000 gpm suction flow,
OR
fully OPEN the valve (100% demand) if 5000 gpm cannot be achieved.

- ☐ 1-FK-2289, SG FW PMP A RECIRC CTRL
- ☐ 1-FK-2290, SG FW PMP B RECIRC CTRL

_______/_______
Initials Date

5.4.18 C. PERFORM the following steps alternately in controlled, incremental steps until the recirc valve for the oncoming FWP is closed.

- ADJUST speed on the oncoming FWP to approach that of the running FWP while maintaining its speed **at or below** that of the running FWP.
  - ☐ - 1-SC-2111B FWPT A MAN SPD CTRL
  - ☐ - 1-SC-2112B FWPT B MAN SPD CTRL
- ☐ CLOSE down on the oncoming FWP recirc valve as much as possible without decreasing flow for the oncoming FWP below 5000 gpm.

_______ / _______
Initials Date

D. WHEN the oncoming FWP Recirc Valve indicates closed,
THEN
PLACE the controller in AUTO:

- ☐ 1-FK-2289, SG FW PMP A RECIRC CTRL
- ☐ 1-FK-2290, SG FW PMP B RECIRC CTRL

_______ / _______
Initials Date

NOTE:	If desired, the pot setting for the oncoming FWP may be adjusted to match FW REF to the current SPD CMD as indicated on the DFS screen to facilitate a bumpless transfer to automatic control.

E. WHEN the oncoming FWP FW REF and SPD CMD are approximately the same on the DFS screen,
THEN
DEPRESS the FWPT SPD CTRL MODE SELECT AUTO pushbutton.

- ☐ 1-HS-2111B, FWPT A SPD CTRL MODE SELECT - AUTO
- ☐ 1-HS-2112B, FWPT B SPD CTRL MODE SELECT - AUTO

_______ / _______
Initials Date

F. ADJUST the FWPT AUTO SPD CTRL Pots as required to balance load and flow.

- ☐ 1-SK-509B, FWPT A AUTO SPD CTRL
- ☐ 1-SK-509C, FWPT B AUTO SPD CTRL

_______ / _______
Initials Date

5.4.18 G. ENSURE the following are CLOSED on the operating pumps (1-CB-08).

- ☐ • 1-HS-2167, FWPT A HP STOP VLV BEF SEAT DRN VLV
- ☐ • 1-HS-2169, FWPT A LP STOP VLV BEF SEAT DRN VLV
- ☐ • 1-HS-2170, FWPT A LP STOP VLV AFT SEAT DRN VLV
- ☐ • 1-HS-2172, FWPT B HP STOP VLV BEF SEAT DRN VLV
- ☐ • 1-HS-2174, FWPT B LP STOP VLV BEF SEAT DRN VLV
- ☐ • 1-HS-2175, FWPT B LP STOP VLV AFT SEAT DRN VLV ________/________

Initials Date

H. RESTORE isolated trip oil pressure switches on the affected FWP as follows:

☐ 1) ENSURE the selected FWP is running AND providing feedwater flow.

2) UN-ISOLATE the selected FWP trip oil pressure switches:

FWP 1-A

- ☐ • 1TO-0331, FWPT 1-A TRIP OIL PRESS IND SW 2111A RT VLV - OPEN
  AND
- ☐ • 1-PS-2111A, FEEDWATER PUMP TURBINE 1-A TRIP OIL PRESSURE INDICATION SWITCH 2111A - GREATER THAN 100 PSIG
- ☐ • 1TO-0332, FWPT 1-A TRIP OIL PRESS IND SW 2111B RT VLV - OPEN
  AND
- ☐ • 1-PS-2111B, FEEDWATER PUMP TURBINE 1-A TRIP OIL PRESSURE INDICATION SWITCH 2111B - GREATER THAN 100 PSIG

________/________

Initials Date

FWP 1-B

- ☐ • 1TO-0333, FWPT 1-B TRIP OIL PRESS IND SW 2112A RT VLV - OPEN
  AND
- ☐ • 1-PS-2112A, FEEDWATER PUMP TURBINE 1-B TRIP OIL PRESSURE INDICATION SWITCH 2112A - GREATER THAN 100 PSIG
- ☐ • 1TO-0334, FWPT 1-B TRIP OIL PRESS IND SW 2112B RT VLV - OPEN
  AND
- ☐ • 1-PS-2112B, FEEDWATER PUMP TURBINE 1-B TRIP OIL PRESSURE INDICATION SWITCH 2112B - GREATER THAN 100 PSIG

________/________

Initials Date

NOTE: Adjustments to maintain Aux Condensers outlet temperatures within 2°F may be performed at any time in this section after the second MFP is placed in service and MFP flows equalized. Local indication listed below may be used instead of Plant Computer points:

- 1-TI-2825 FWPT 1-A AUX CONDENSER 1-A CWS OUTLET TEMP INDICATOR
- 1-TI-2833 FWPT 1-B AUX CONDENSER 1-B CWS OUTLET TEMP INDICATOR

5.4.18 I. CHECK Aux Condenser circ water outlet temperatures on Plant Computer:

- ☐ • T2406A, AUX CNDSR A OUT TEMP
- ☐ • T2407A, AUX CNDSR B OUT TEMP

_______/_______
Initials Date

NOTE: Adjustment of the Aux Condenser outlet valves in the OPEN direction will cause differential pressure to rise due to the pressure being monitored across the HX (valve closure causes DP to lower).

J. IF temperature differential is > 2°F,
THEN
ADJUST Aux Condenser outlet valves until outlet temperatures are ≤ 2° F:

- ☐ • 1CW-0014, FW PMP TURB 1-A AUX CNDSR 1-A CWS OUT VLV (1-PIS-2885)
- ☐ • 1CW-0016, FW PMP TURB 1-B AUX CNDSR 1-B CWS OUT VLV (1-PIS-2886)

_______/_______
Initials Date

5.4.19 PREPARE AMSAC for service:

[C] A. CONTACT Prompt Team to ensure INC-4909 for AMSAC has been completed within the required frequency.

_______/_______
Initials Date

[C] B. At the AMSAC Cabinet (TBX-ESELAM-01, E. SIDE) ENSURE the SYSTEM MODE switch is in NORMAL.

_______/_______
Initials Date

[C] C. At the AMSAC Cabinet ENSURE the SYSTEM BYPASS switch is in NORMAL.

_______/_______
Initials Date

5.4.20 ENABLE the Main Steamline N-16 Radiation monitor channel alarms per SOP-706 when Reactor power is above approximately 40%.

- ☐ • N16-174 (1-RE-2325A, MSL 1-01 SG LEAK RATE MONITOR DETECTOR)
- ☐ • N16-175 (1-RE-2326A, MSL 1-02 SG LEAK RATE MONITOR DETECTOR)
- ☐ • N16-176 (1-RE-2327A, MSL 1-03 SG LEAK RATE MONITOR DETECTOR)
- ☐ • N16-177 (1-RE-2328A, MSL 1-04 SG LEAK RATE MONITOR DETECTOR)

_______ / _______
Initials Date

5.4.21 WHEN Turbine load is above 40%, THEN VERIFY 1-PCIP, 1.3, AMSAC BLK TURB <40% PWR C-20 is OFF.

_______ / _______
Initials Date

5.4.22 ENSURE 1GS-0072, U1 FWPT GS SPLY VLV BYP VLV is CLOSED.

_______ / _______
Initials Date

A. VERIFY 1-PI-3917, U1 FW PUMP TURBINE GLAND STEAM SUPPLY HEADER PRESSURE INDICATOR between 2 and 4 psig.

_______ / _______
Initials Date

NOTE:	To ensure the accuracy of nuclear instrumentation, alternate indication of power level should be used to verify the validity of nuclear instruments and power level indications.

5.4.23 WHEN Reactor power is at approximately 45%, THEN STOP Turbine loading and perform the following:

A. Prior to increasing Reactor power above 50% ENSURE OPT-104A to document Axial Flux Difference is current within its required frequency (TS SR 3.2.3.1).
AND
VERIFY the AFD Monitor Alarm (1-ALB-6 D, window 4.11) is OPERABLE.

_______/_______
Initials Date

B Prior to increasing Reactor power above 50% ENSURE OPT-309 is complete.
(TS SR 3.3.1.2.2a, 3.3.1.2.6, and 3.3.1.2.7).

_______/_______
Initials Date

C. COMPARE N-16 Power to indicated Reactor power.

_______/_______
Initials Date

D. PERFORM a Quadrant Power Tilt Ratio calculation per OPT-302.

_______/_______
Initials Date

E. CONTACT Chemistry to determine if SG and secondary Chemistry parameters are in specification per STA-610 prior to exceeding 50%.

____
Name of Chemist Contacted

_______/_______
Initials Date

5.4.24 RE-INITIATE Turbine loading to approximately 50% Turbine load.

_______/_______
Initials Date

5.4.25 WHEN Reactor power is >48%,
THEN
VERIFY 1-PCIP, 4.5, RX ≤48% PWR 3-LOOP FLO PERM P-8 is OFF.

_______/_______
Initials Date

5.4.26 VERIFY the 3-Loop flow permissive P-8 status lights are ON:

- ☐ • 1-TSLB-9, 1.7, RX ≥48% PWR NC-41N
- ☐ • 1-TSLB-9, 2.7, RX ≥48% PWR NC-42N
- ☐ • 1-TSLB-9, 3.7, RX ≥48% PWR NC-43N
- ☐ • 1-TSLB-9, 4.7, RX ≥48% PWR NC-44N

_______ / _______
Initials Date

5.4.27 <u>WHEN</u> Reactor power is >50%,
<u>THEN</u>
VERIFY 1-PCIP, 1.7, RX ≤50%
PWR TURB TRIP PERM P-9 is OFF.

_______ / _______
Initials Date

5.4.28 VERIFY the permissive P-9 status lights are ON:

- ☐ • 1-TSLB-3, 1.9, RX >50% PWR NC-41S
- ☐ • 1-TSLB-3, 2.9, RX >50% PWR NC-42S
- ☐ • 1-TSLB-3, 3.9, RX >50% PWR NC-43S
- ☐ • 1-TSLB-3, 4.9, RX >50% PWR NC-44S

_______ / _______
Initials Date

<u>CAUTION</u>:

- Control Rods may be withdrawn at a maximum rate of 3 steps/hr above 50% until fuel conditioning has been performed as directed by Core Performance Engineering.
- OBSERVE Fuel conditioning limits during all Reactor power increases.

<u>NOTE</u>:

- Prior to increasing Reactor power above 50%, reasonable AFD stability needs to exist. Power should not be increased until AFD can be steadily maintained inside the operating limits. Control rod height should be adjusted as necessary to maintain AFD within the administrative limit of ±2% about the target value or as specified by Core Performance Engineering.
- During operation at BOL with a positive moderator temperature coefficient, a reduction in RCS temperature will result in negative reactivity being added to the core. REF Note 4.2.23

|

5.4.29 RAISE Turbine load to approximately 1081 MW (85%) as follows:

CAUTION: Following a Refueling, Power Range Trip Setpoints are reduced to 90% and SHALL NOT be reset to 109% until INC-7018A is completed per NUC-101. (Reference LCO 3.3.1)

NOTE:

- For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the reactivity plan. REF note 4.2.24
- While TSE Influence is off, any INCREASE in Turbine load is limited to 5 MW/min
- While TSE Influence is off, with a TSE fault present, the following limits apply:
  - Turbine speed should be held at warm-up speed (500 RPM) for a minimum of 20 minutes, prior to commencing ramp to 1800 RPM
  - Following initial synchronization, turbine load increases should be limited to a load rate of 2.27 MW/min while $\leq$ 400 MWe, THEN limited to 5 MW/min while greater than 400 MWe
  - Turbine load decreases (excluding runbacks) should be limited to a load rate of 10 MW/min while > 400 MWe, THEN limited to 5MW/min while $\leq$ 400 MWe (during rapid cooldown, a 2-hour HOLD at 400 MWe is required for temperature equalization)

[C] A. WHEN the following are met:
1) Turbine load is greater than 700 MWe.
2) No TSE alarms are active
3) MATCH turbine load/speed with target load/speed
THEN
TURN OFF TSE Influence.

_______/_______
Initials Date

B. IF startup is being conducted following a Refueling Outage,
THEN
ENSURE RCS total flow rate measurement will be performed prior to exceeding 85% power per INC-7018A (TS SR 3.4.1.4).

_______/_______
Initials Date

C. IF desired,
THEN
DETERMINE the amount of dilution required to raise Reactor power to approximately 85% using the appropriate currently approved Reactivity Projection.

_______/_______
Initials Date

5.4.29 D. IF desired,
THEN
DETERMINE the rate of dilution required to allow slow control rod outward motion as the Turbine load increases, using the appropriate currently approved Reactivity Projection.

_______/_______
Initials Date

E. REFER to Attachment 2 for guidance in controlling AFD during power increases.

_______/_______
Initials Date

F. INITIATE RCS boration/dilution using SOP-104A.

_______/_______
Initials Date

NOTE: Primary plant should lead secondary plant during Main Turbine load changes.

G. In the "Load Control" Section, SET in the desired loading rate using the Load Rate Setpoint Controller.

_______/_______
Initials Date

NOTE:
- The load will immediately begin increasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
- It may be necessary to raise Turbine Load in increments to maintain Ramp Rate Restrictions.

H. In the "Load Control" Section, RAISE the Load Target Setpoint Controller as necessary to obtain 1081 MW while controlling the rate of Turbine power increase.

_______/_______
Initials Date

5.4.30 REFER to Attachment 10 for Stator Bar Monitoring temperature information.

_______/_______
Initials Date

5.4.31 WHEN Extraction Steam pressure is >80 psig on 1-PI-2356, MSR A COLD RHT IN PRESS,
THEN
TRANSFER the 50 pound Auxiliary Steam Header from Main Steam to Extraction Steam per SOP-311.

_______/_______
Initials Date

> CAUTION: Instructions to place 5A/6A and 5B/6B heaters in service ensures the heater string is filled and vented. The Main Feedwater Pumps could trip if the heater string is not filled and vented prior to establishing condensate flow through the heaters.

[C] 5.4.32 ESTABLISH condensate flow through 5/6 heaters AND ISOLATE 5/6 heater bypass flow per SOP-303A.

_____/_____ Initials Date

5.4.33 WHEN Reactor Power is approximately 75%, THEN ENSURE the following valves are CLOSED:

- ☐ 1CO-0090, FW HTR 1-5A/1-6A CNDS IN VLV 2611A EQUAL BYP VLV
- ☐ 1CO-0091, FW HTR 1-5B/1-6B CNDS IN VLV 2612A EQUAL BYP VLV
- ☐ 1CO-0110, FW HTR 1-5A/1-6A CNDS OUT VLV 2611B EQUAL BYP VLV
- ☐ 1CO-0111, FW HTR 1-5B/1-6B CNDS OUT VLV 2612B EQUAL BYP VLV

_____/_____ Initials Date

5.4.34 PERFORM the following steps to fully pressurize the Moisture Separator Reheaters:

A. On the MSR Display, VERIFY the MSR HTG STM CTRL VLVs are 100% OPEN:

- ☐ 1-TV-6580A, MSR A HTG STM CTRL VLV
- ☐ 1-TV-6580B, MSR A HTG STM CTRL VLV
- ☐ 1-TV-6580C, MSR A HTG STM CTRL VLV
- ☐ 1-TV-6581A, MSR B HTG STM CTRL VLV
- ☐ 1-TV-6581B, MSR B HTG STM CTRL VLV
- ☐ 1-TV-6581C, MSR B HTG STM CTRL VLV

_____/_____ Initials Date

B. In the “MSR Setpoint” Section, PLACE both MSR Heating Steam Controllers in MANUAL (Green) AND the “Demands” are at 100% for both using the “Osd”.

_____/_____ Initials Date

C. OPEN 1-HS-6582, MSR HTG STM SPLY VLV.

_____/_____ Initials Date

D. OPEN the excess heating steam line isolation valves.

- 1HD-0932, HTR DRN SYS MSR 1-A XS HTG STM ISOL VLV
- 1HD-0936, HTR DRN SYS MSR 1-B XS HTG STM ISOL VLV

_____/_____ Initials Date

5.4.34 E. To close the MSR Heating Steam Control Valves, PERFORM the following:

1) In the “MSR Setpoint” Section, PLACE both MSR Heating Steam Controllers “Output” to 0%.

_______/_______
Initials Date

2) VERIFY the MSR Heating Steam Control Valves close:

- ☐ • 1-TV-6580A, MSR A HTG STM CTRL VLV - CLOSED
- ☐ • 1-TV-6580B, MSR A HTG STM CTRL VLV - CLOSED
- ☐ • 1-TV-6580C, MSR A HTG STM CTRL VLV - CLOSED
- ☐ • 1-TV-6581A, MSR B HTG STM CTRL VLV - CLOSED
- ☐ • 1-TV-6581B, MSR B HTG STM CTRL VLV - CLOSED
- ☐ • 1-TV-6581C, MSR B HTG STM CTRL VLV - CLOSED

_______/_______
Initials Date

F. VERIFY the Hot Reheat Steam temperatures and pressures remain stable as indicated on 1-PR-2357/58, points 5, 6.

_______/_______
Initials Date

G. VERIFY no unexpected or sudden increase in vibration is indicated:

- ☐ • Turbine Display
- ☐ • Generator Display
- ☐ • Alarm Summary Display (Asd)

_______/_______
Initials Date

5.4.35 IF startup is being conducted following a Refueling Outage,
THEN
SET Power Range Trip Setpoints for full power operation:

A. ENSURE RCS total flow rate measurement surveillance of INC-7018A (TS SR 3.4.1.4) has been completed.

_______/_______
Initials Date

B. ENSURE Power Range Trip Setpoints have been reset to 109% per INC-7375A (Reference LCO 3.3.1).

_______/_______
Initials Date

CAUTION:
- Control Rods may be withdrawn at a maximum rate of 3 steps/hr above 50% until fuel conditioning has been performed as directed by Core Performance Engineering.
- Observe Fuel conditioning limits during all Reactor power increases.

NOTE:
- Prior to increasing Reactor power above 50%, reasonable AFD stability needs to exist. Power should not be increased until AFD can be steadily maintained inside the operating limits. Control rod height should be adjusted as necessary to maintain AFD within the administrative limit of ±2% about the target value or as specified by Core Performance Engineering.
- During operation at BOL with a positive moderator temperature coefficient, a reduction in RCS temperature will result in negative reactivity being added to the core. REF Note 4.2.23 |
- For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the reactivity plan. REF note 4.2.24 |

5.4.36 RAISE Turbine load to approximately 1145 MW (90%) as follows:

A. IF the startup is following a Refueling Outage,
THEN
ENSURE the assumptions for power ascension from NUC-101 Attachment 5 have been reviewed prior to ramping to 100% Reactor power.

_______/_______
Initials Date

B. IF desired,
THEN
DETERMINE the amount of dilution required to raise Reactor power to approximately 90% using the currently approved Reactivity Projection.

_______/_______
Initials Date

C. IF desired,
THEN
DETERMINE the rate of dilution required to allow slow control rod outward motion as the Turbine load increases, using the appropriate currently approved Reactivity Projection.

_______/_______
Initials Date

D. REFER to Attachment 2 for guidance in controlling AFD during power increases.

_______/_______
Initials Date

5.4.36 E. INITIATE RCS boration/dilution using SOP-104A. ________/________ Initials Date

> NOTE: Primary plant should lead secondary plant during Main Turbine load changes.

F. In the "Load Control" Section, SET in the desired loading rate using the Load Rate Setpoint Controller. ________/________ Initials Date

> NOTE:
> - The load will immediately begin increasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
> - It may be necessary to raise Turbine Load in increments to maintain Ramp Rate Restrictions.

G. In the "Load Control" Section, RAISE the Load Target Setpoint Controller as necessary to obtain 1145 MW WHILE CONTROLLING the rate of Turbine power increase. ________/________ Initials Date

5.4.37 WHEN Turbine load is approximately 90%,
THEN
PERFORM the following:

A. PERFORM a calorimetric per OPT-309. ________/________ Initials Date

B. IF needed to assist in maintaining HDT level,
THEN
PERFORM the following:

☐ 1) ENSURE 1-FK-2239 toggle switch is in TRIP-TO-AUTO ENABLE.

> CAUTION: FWP Suction pressure should be closely monitored while opening 1-FK-2239. If FWP suction pressure starts to approach 320 psig, 1-FK-2239 should be throttled in the closed direction until suction pressure recovers.

> NOTE: 1-FV-2239, CNDS PMP 1-01/1-02 RECIRC FLO CTRL VLV should NOT be manually opened greater than 75% WHEN two Condensate Pumps are running due to piping vibrations experienced at higher flow. This is an administrative limit and should be removed when the vibration issue is resolved. (AI-CR-2010-000540-03)

2). While closely monitoring FWP suction pressure, slowly OPEN 1-FK-2239, CNDS PMP RECIRC CTRL to establish the desired effects of the following:

- ☐ 1-ZL-2594, HDT ALT DRN VLV - FULL CLOSED
- ☐ 1-LK-2592,HDP DISCH VLV - Less than 100% OPEN ________/________ Initials Date

5.4.38 DETERMINE NIS detector plateau surveillance status:

A. CONTACT maintenance to verify INC-7387A, INC-7388A, INC-7389A and INC-7665A for all detector plateau surveillances are current within the required frequency (18 months). (TS SR 3.3.1.10.6, 3.3.1.10.7, 3.3.1.11.2a, 3.3.1.11.4)

_______/_______
Initials Date

B. IF detector plateau surveillances are required,
THEN
ENSURE surveillances are performed within 72 hours after reaching Reactor power equilibrium $\geq$90%.

_______/_______
Initials Date

5.4.39 ADJUST 1CO-0255 as necessary to maintain <1140 gpm as indicated on 1-FI-2243, TURB GLND STM CNDSR CNDS FLO.

_______/_______
Initials Date

CAUTION: OBSERVE Fuel conditioning limits during all Reactor power increases.

NOTE: For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the reactivity plan. REF note 4.2.24

5.4.40 PERFORM the following steps to raise Turbine load to approximately 100% Reactor Power.

A. IF desired,
THEN
CALCULATE the amount of dilution required to raise Reactor power to approximately 100% using the appropriate curves in the NDR
OR
OBTAIN boration/dilution calculations from Core Performance Engineering.

_______/_______
Initials Date

B. IF desired,
THEN
CALCULATE the rate of dilution required to allow slow control rod outward motion as the turbine load increases, using the appropriate curves in the NDR
OR
OBTAIN boration/dilution calculations from Core Performance Engineering.

_______/_______
Initials Date

5.4.40 C. REFER to Attachment 2 for guidance in controlling AFD during power increases. ________/________ Initials Date

D. INITIATE RCS boration/dilution using SOP-104A. ________/________ Initials Date

> NOTE: Primary plant should lead secondary plant during Main Turbine load changes.

E. In the “Load Control” Section, SET in the desired loading rate using the Load Rate Setpoint Controller. ________/________ Initials Date

> NOTE:
> - The load will immediately begin increasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
> - It may be necessary to raise Turbine Load in increments to maintain Ramp Rate Restrictions.

F. In the “Load Control” Section, RAISE the Load Target Setpoint Controller as necessary to obtain approximately 100% Reactor Power WHILE CONTROLLING the rate of turbine power increase. ________/________ Initials Date

> NOTE:
> - The intent of the following step sequence is to establish 100% power and perform final system adjustments for steady state operations. If steady state is something less than full power, the steps after 5.4.41 may be performed in the order necessary to complete unit startup.

5.4.41 ADJUST Turbine load as necessary to maintain approximately 3612 MWth Reactor power as indicated on the Plant Computer PPP Calorimetric (See flowchart in Section 5.5 for power limitations if PPPC is not available). ________/________ Initials Date

5.4.42 ENSURE 1-PI-6557, GEN H_2 PRESS is 62 to 65 psig (1-CB-11). ________/________ Initials Date

5.4.43 IF power increase is following a Unit startup,
THEN
BLOWDOWN steam traps listed in Attachment 15, Steam Trap Blowdown. ________/________ Initials Date

5.4.44 PERFORM the following steps to adjust the Moisture Separator Reheater excess heating steam flow:

NOTE:	Due to the location of the Temperature Probes on the MSR Tubesheets, the Tubesheet temps on the MSR Display may have a difference of more than 15°F. Therefore, the MSR Tubesheet Temperatures on the EXP #2 MSR Temperatures Display may be used to determine deltaT.

A. VERIFY the difference between MSR Saturation Temp's on the "MSR" Display and MSR tubesheet temperatures are ≤15°F.

MSR 1-A (MSRL)

- ☐ Saturation Temp 1-A
- ☐ MSR 1-A "Tubesheet" Temperature

MSR 1-B (MSRR)

- ☐ Saturation Temp 1-B
- ☐ MSR 1-B "Tubesheet" Temperature

_______/_______
Initials Date

NOTE:	The final position of 1HD-0933 and 1HD-0937 is set to 1/4 to 1/8 turns from FULL SHUT in the following step, ensuring steam flow is present through orifice while preventing line surges for maximum thermal efficiency.

B. IF the temperature difference between MSR Saturation Temp's in the "MSR Setpoint" Section and tubesheet temperatures >15°F,
THEN
PERFORM the following:

1) NOTIFY System Engineering to assist in adjusting MSR excess heating steam flow.

_______/_______
Initials Date

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5.4.44 B. 2) ADJUST excess heating steam orifice isolation valves to establish a difference of <15°F between MSR Saturation Temp's in the "MSR Setpoint" Section and tubesheet temperatures:

MSR 1-A (MSRL)

- ☐ • 1HD-0933, HTR DRN SYS MSR 1-A XS HTG STM ORIF UPSTRM ISOL VLV
- ☐ • Saturation Temp 1-A
- ☐ • MSR 1-A "Tubesheet" Temperature

MSR 1-B (MSRR)

- ☐ • 1HD-0937, HTR DRN SYS MSR 1-B XS HTG STM ORIF UPSTRM ISOL VLV
- ☐ • Saturation Temp 1-B
- ☐ • MSR 1-B "Tubesheet" Temperature

________/________
Initials Date

NOTE: During initial adjustment of the MSR heating steam, the MSRs may experience surges caused by insufficient excess heating steam.

3) IF necessary to increase MSR tubesheet temperatures,
THEN
THROTTLE OPEN the heating steam orifice bypass valve.

- ☐ • 1HD-0935, HTR DRN SYS MSR 1-A XS HTG STM ORIF BYP VLV
- ☐ • 1HD-0939, HTR DRN SYS MSR 1-B XS HTG STM ORIF BYP VLV

________/________
Initials Date

C. IF step 5.4.44.B is N/A,
THEN
ENSURE 1HD-0933 AND 1HD-0937 are 1/4 to 1/8 turns from full shut.

________/________
Initials Date

5.4.45 After reaching full power and fuel conditioning requirements are met, PERFORM the following:

A. NOTIFY QSE Generation Controller by updating GAPS for the change in “Unit Status” to “On-Line and Released (OR)” to show that the unit is released for full power operation.

_______/_______
Initials Date

B. VERIFY Main Generator AVR is in automatic mode of operation

_______/_______
Initials Date

> CAUTION: Control Rods should NOT be placed in automatic until fuel conditioning requirements for Rod Withdrawal Limitation are satisfied.

> NOTE: To ensure NO demand for automatic rod motion, verify the Circuit 1 output LED (outward motion) and the Circuit 2 output LED (inward motion) are OFF. Located in 1-RK-08, CF06, Card 41, labeled 1-SB-0412A and 1-SB-0412B.

5.4.46 IF desired,
THEN
PLACE the Control Rods in automatic as follows:

A. VERIFY 1-PCIP, 2.4, LO TURB PWR ROD WITHDRWL BLK C-5 is OFF.

_______/_______
Initials Date

B. WHEN Tavg is within 1°F of Tref and no automatic rod motion demand,
THEN
PLACE 1/1-RBSS, CONTROL ROD BANK SELECTOR in AUTO.

_______/_______
Initials Date

> NOTE: Standard Clearance #4860 was hung on PDP handswitch by IPO-002A.

5.4.47 ENSURE Standard Clearance #4860 on PDP handswitch has been removed.

_______/_______
Initials Date

5.4.48 ENSURE the following Main Steam line drain valves are CLOSED:

- ☐ • 1MS-0030, MSL 1-01 BEF MSIV D\POT 1-25 DRN ORIF OUT VLV
- ☐ • 1MS-0067, MSL 1-02 BEF MSIV D\POT 1-24 DRN ORIF OUT VLV
- ☐ • 1MS-0102, MSL 1-03 BEF MSIV D\POT 1-23 DRN ORIF OUT VLV
- ☐ • 1MS-0138, MSL 1-04 BEF MSIV D\POT 1-26 DRN ORIF OUT VLV

_______/_______
Initials Date

5.4.49 PERFORM the following to check proper flow:

☐ 1) THROTTLE 1CO-0276, AUX GLND STM CNDSR 1-02 CNDS OUT VLV as necessary to establish approximately 338 gpm (flow limit < 338 gpm) as indicated on 1-FI-2251, AUX GLND STM CNDSR CNDS FLO.

☐ 2) THROTTLE 1CO-0255, TURB GLND STM CNDSR 1-01 CNDS OUT VLV as necessary to establish approximately 1140 gpm (flow limit <1140 gpm) as indicated on 1-FI-2243, TURB GLND STM CNDSR CNDS FLO.

_______/_______
Initials Date

> <u>NOTE</u>: Adjustments to maintain Aux Condensers outlet temperatures within 2°F may be performed at any time in this section after the second MFP is placed in service and MFP flows equalized. Local indication listed below may be used instead of Plant Computer points:
>
> - 1-TI-2825 FWPT 1-A AUX CONDENSER 1-A CWS OUTLET TEMP INDICATOR
> - 1-TI-2833 FWPT 1-B AUX CONDENSER 1-B CWS OUTLET TEMP INDICATOR

> <u>NOTE</u>: For maximum thermal efficiency, the Aux Condenser outlet temperatures should normally be adjusted within 2°F of each other as well as within 2°F of the average of the 4 Main Condenser Water Box Outlets.

5.4.50 BALANCE Aux Condenser circ water outlet temperatures as follows:

A. CHECK Aux Condenser circ water outlet temperatures on Plant Computer:

- ☐ • T2406A, AUX CNDSR A OUT TEMP
- ☐ • T2407A, AUX CNDSR B OUT TEMP

_______/_______
Initials Date

NOTE: Adjustment of the Aux Condenser outlet valves in the OPEN direction will cause differential pressure to rise due to the pressure being monitored across the HX (valve closure causes DP to lower).

5.4.50 B. IF temperature differential is > 2°F,
THEN
ADJUST Aux Condenser outlet valves until outlet temperatures are ≤ 2° F.

- ☐ 1CW-0014, FW PMP TURB 1-A AUX CNDSR 1-A CWS OUT VLV (1-PIS-2885)
- ☐ 1CW-0016, FW PMP TURB 1-B AUX CNDSR 1-B CWS OUT VLV (1-PIS-2886)

_______/_______
Initials Date

5.4.51 NOTIFY Chemistry to return CAG-197 setpoints to the default values after the unit has returned to 100% power per CLI-741.

_______/_______
Initials Date

5.4.52 IF PRZR Spray Valve has been replaced,
THEN
RE-ADJUST the Pressurizer Spray Bypass Valves per Attachment 12 of IPO-001A
AND
PLACE in the throttled position as required by TDM-901A.

- ☐ 1RC-8051, RC Loop 1-01 to PRZR 1-01 SPR VLV BYP VLV
- ☐ 1RC-8052, RC Loop 1-04 to PRZR 1-01 SPR VLV BYP VLV

_______/_______
Initials Date

5.4.53 ADJUST 1-PC-5223 SGBD HX 1-01 CNDS SPLY CTRL VLV for normal operating pressure (210-225 psig)

_______/_______
Initials Date

5.4.54 Have PROMPT ADJUST Heater Drain Pump Seal Water Controllers for 100% power operation.

_______/_______
Initials Date

5.4.55 IF required
THEN
BALANCE SGBD flows per SOP-305A.

_______/_______
Initials Date

5.4.56 WHEN all required steps in the sections to increase power to the desired constant load have been completed, OBTAIN Shift Manager approval,
THEN
PROCEED with Section 5.5 to maintain constant load
OR
Section 5.6 to reduce turbine power
AND
FILE these procedure sections in accordance with ODA-104. ________/________
Initials Date

COMMENTS: ____

____

____

____

____

IPO-003A Satisfactorily completed:____/________
SHIFT MANAGER DATE

5.5 **Operating At Constant Turbine Load**

The following lists conditions and anticipatory responses that should be reviewed while operating at constant Turbine load:

A. Reactor Operation

- N-16 should be MONITORED as an indication of power along with NIS and Calorimetric power. N-16 may be the most accurate indicator of power during a transient since it is temperature compensated. During transient conditions, the highest indication of Reactor power (N-16 and NIS) should always be maintained within limits.

- MAINTAIN the Axial Flux Difference within the AFD administrative band specified in NUC-204 and at or near the target AFD. The AFD administrative band specified by NUC-204 is identified as an administrative limit in this procedure.

- CONTACT Core Performance Engineering to obtain fuel conditioned power restrictions.

- An administrative AFD limit of ±2% about the target value should be MAINTAINED during steady state operation. If AFD deviates outside this limit or if AFD oscillations occur, immediate operator action should be initiated to restore AFD within its administrative limit. This limitation may be modified by Core Performance Engineering based on core operating data.

- If I-131 values increase to more than 25% above its equilibrium value, sample frequency and data collection should be IMPLEMENTED per STA-735. If failed fuel is detected, the Failed Fuel Action Guidelines of STA-735 should be REVIEWED for applicability. These guidelines may place additional restrictions on power level and ramp rates.

- PERFORM minimum control rod motion when operating at constant high power conditions to minimize flux oscillations.

- Control rod use should be minimized. Boration and dilution should be used to assist rod movement to compensate for the following:

  - Maintain T_{avg} within 1°F of T_{ref}.

  - To force the Axial Flux Difference to the target AFD during Reactor power changes.

  - To keep the Axial Flux Difference within the AFD administrative band during reduced power operation.

  - To dampen Xenon Oscillations as described on Attachment 2.

5.5 A. Reactor Operation (continued)

- If there is reason to believe Rods may step when going to Auto from Manual, Rod motion demand for automatic rod motion can be checked. Verify the Circuit 1 output LED (outward motion) and the Circuit 2 output LED (inward motion) are OFF. Located in RK-08, CF06, Card 41, labeled 1-SB-0412A and 1-SB-0412B.

- Alternate dilution may be used to compensate for fuel burnup as long as RCS hydrogen concentration can be maintained within specifications.

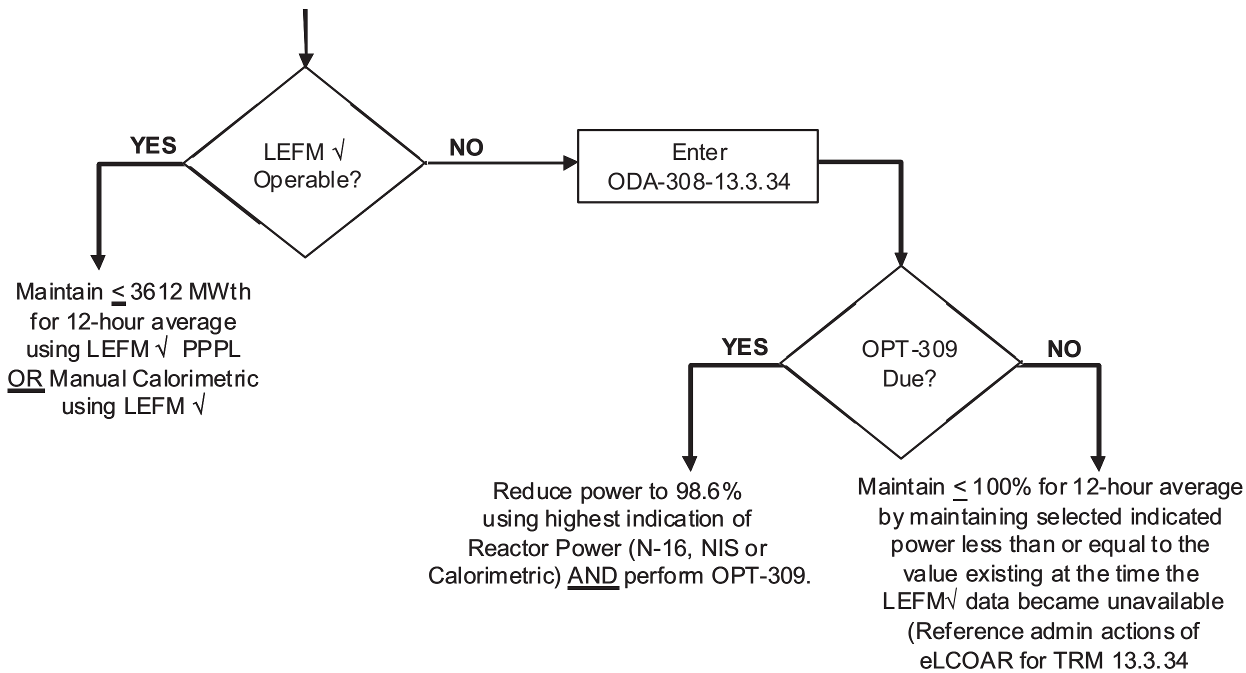
- Steady State implies that temperatures, pressures, and flows are stable such that the nominal value of reactor power remains stable, subject to statistical uncertainties and normal fluctuations (e.g., feedwater oscillations).

- The 2 hour and 12 hour averages are monitored and trended to ensure compliance with the licensed thermal limit. The 1 hour average is used to control/trend thermal power. Utilizing the 1 hour average ensures that the 2 hour and 12 hour averages are maintained < RTP. Other averages (1m, 15m, 30m, 1h, 8h) may be used for trending and anticipatory response to changing plant conditions. Averages < 1 hour are used for trending purposes only due to large variations associated with feedwater oscillations, changes in reactive load, etc.

- The average thermal power level over any 12 hour period shall not exceed:

  - 3612 MWth (100% RTP) when the LEFM✔ has been used to perform last calorimetric per SR 3.3.1.2,
    or
  - 3562 MWth (98.6% RTP) when the Feedwater Venturis (or MCB indication) have been used to perform the last calorimetric per SR 3.3.1.2 (TR 13.3.34).

5.5.A. • The following flowchart provides a simplified guideline for maintaining Unit 1 plant power. A detailed description is given in the subsequent paragraphs.



- The Plant Computer, Primary Plant Performance Calorimetric using the LEFM ✔ is the preferred method for measurement of Thermal Power per OPT-309. Thermal Power may be monitored using the Plant Computer, Primary Plant Performance Calorimetric form LEFM ✔ (POWERL) when this indication is available and LEFM ✔ has been used to perform last calorimetric. Operation at a RTP of 3612 MWth is allowed when the LEFM ✔ is used for feedwater flow in the calorimetric measurement. In this configuration, accident analysis requires a ± 0.6% RTP allowance for the calorimetric uncertainty.

- <u>IF</u> the LEFM ✔ becomes unavailable during the intervals between performance of SR 3.3.1.2 for the OPT-309 calorimetric measurement, <u>THEN</u> operation may continue using highest indication of Reactor power (N-16, NIS or Calorimetric). <u>A preparatory turbine power reduction of ~ 0.5MWe may be taken to ensure that power remains at or below 100%.</u>

- <u>WHEN</u> the LEFM ✔ or POWERL is NOT available, <u>THEN</u> the Plant Computer, Primary Plant Performance Calorimetric using the Corrected Feedwater Venturis (POWERC) provides the next desired method for measurement and monitoring of Thermal Power. Operation is restricted to a Thermal Power of 3562 MWth when the Feedwater Venturis are used for feedwater flow in the calorimetric measurement. In this configuration, the accident analysis requires a ± 2% RTP allowance for the calorimetric uncertainty.

5.5 A. Reactor Operation (continued)

- IF the Plant Computer is NOT available, THEN operation may continue using highest power indication of Reactor power from N-16 or NIS to monitor Thermal Power. OPT-309 manual calculation (using a validated computer program on the Control Room PC) may be used for measurement of Thermal Power if the Plant Computer, Primary Plant Performance Calorimetric is NOT available. Operation is restricted to a Thermal Power of 3562 MWth when the Feedwater Venturis are used for feedwater flow in the calorimetric measurement. In this configuration, the accident analysis requires a ± 2% RTP allowance for the calorimetric uncertainty.

- While maintaining power near the Rated Thermal Power limit, Reactor thermal power should be monitored at least once every thirty (30) minutes. This may be accomplished using the Plant Computer, Primary Plant Performance Calorimetric. IF a planned outage of the Plant Computer or LEFM ✔ is scheduled AND NIS or N16 indicates greater than 100% RTP (3612 MWth), THEN a calorimetric should be performed and the NIS and N16 channels should be adjusted per OPT-309.

- Performance of the calorimetric using venturis (POWERC, POWERV, or MANUAL with venturis) during extended power operation below 55% RTP AND a subsequent reduction in NIS Power Range or N-16 channel output has the potential to place the Unit in a condition outside the safety analysis limit (i.e reactor trip originating from Power Range or N-16 indication may be above that value assumed in the safety analysis). Therefore additional controls exist in ODA-308-13.3.34 for performance of a calorimetric using FW venturis with the Unit operating in extended power operation below 55% RTP.

- A power reduction, such as required by OPT-217A near end of core life requires special consideration for managing reactivity. The amount of boron used to reduce Reactor power must be minimized to limit the amount of dilution and subsequent time requirements for return to power. Utilizing BTRS or an unsaturated CVCS demineralizer should be considered to limit dilution volumes. Core Performance Engineering may be contacted to provide recommendations for ramp rates, ΔI control and a pre-planned core reactivity balance for scheduled power reductions. This information may be used as a job aid to provide general guidelines for conducting power reductions.

- Near end of core life, power coastdown may be initiated to extend the time to Refueling. Approximately 2% power/day will be required to maintain Tavg within 1°F of Tref. Core Performance Engineering may modify existing ΔI administrative controls, as required, to provide for optimal fuel utilization prior to reload.

- WHEN Reactor power will be increased by ≥20%, THEN ODA-308 should be REVIEWED to determine whether additional $F_Q(Z)$ measurements will be required.

5.5 A. Reactor Operation (continued)

- Power Change Log should be INITIATED during UP-POWER evolutions >20% when reactor power is >20% Rated Thermal Power OR during any UP-POWER when ramp rate limit is < 15% per hour (typically for fuel conditioning) when reactor power is >20%.

[C]
- Thermal power changes $\geq$15% of Rated Thermal Power within 1 hour requires NOTIFICATION of Chemistry and Radiation Protection as soon as possible. This allows them to perform required sampling surveillances within the specified time limits (TS SR 3.4.16.2, ODCM 4.11.2.1.1.2 and 4.11.2.1.1.3)

5.5 B. Secondary Operation

- OPERATE the Turbine generator within the limits specified in TDM-401A.

- Attachment 6 may be UTILIZED to reduce power, as required, to perform stroke testing on the Main Turbine Stop and Control Valves.

- Periodically MONITOR Circulating Water inlet temperature and operate CWPs to optimize efficiency per TDM-310A.

- Normal full flow through Turbine Gland Steam Condenser (1140 gpm) is based on erosion of tubes. Short term operation with flow >1140 gpm but <1280 gpm is permitted. 1CO-0255 may be throttled as necessary to maintain <1140 gpm as indicated on 1-FI-2243, TURB GLND STM CNDSR CNDS FLO.

- The Low Pressure Turbine installed during 1RF10 may provide more extraction steam drain flow to the Heater Drain Tanks than the Heater Drain Pumps can forward flow. The inability of the Heater Drain Pumps to maintain Heater Drain Tank level will be indicated by the Heater Drain Pump discharge valve being full open or Heater Drain Tank alternate drain valve opening. The Condensate Pump Recirc valve may be placed in manual and opened to redirect a portion of the Condensate Pump flow back to the condenser. This will reduce the pressure at the discharge of the Heater Drain Pumps and increase Heater Drain Pump flow. Feedwater Pump suction pressure should be closely monitored while throttling 1-FV-2239. During throttling of 1-FV-2239, the following valves should be monitored for the desired effect:

  - 1-ZL-2594, HDT ALT DRN VLV - FULL CLOSED

  - 1-LK-2592,HDP DISCH VLV - Less than 100% OPEN

- When 1-FK-2239, CNDS PMP RECIRC CTRL is throttled for the purpose above, the TRIP-TO-AUTO feature shall be enabled using the Toggle Switch on the controller. With the Switch in the "TRIP-TO-AUTO ENABLE" position the controller will trip to Auto on a low flow condition.

5.5 C. General

- INFORM Core Performance Engineering of any substantial reduction in power (>25%).

- Maximum Generation Verification testing should be PERFORMED upon request from the QSE Generation Controller.

- When an electric grid "Hands Off" Condition has been declared OR QSE Generation Controller or TGM Transmission Grid Controller has informed unit that grid conditions exist such that inadequate voltage may exist on loss of a unit, PERFORM the following:

  - EVALUATE surveillance testing or high risk activities which may jeopardize unit availability can be minimized as much as practical.

  - NOTIFY WCC Work Week Coordinator of declared condition.

  - For potential inadequate voltage, REFER to ABN-601 for potentially degraded off-site power system voltage.

- When an outage is planned within the next eight week period, REVIEW Attachment 5 to determine whether system alignments or other activities should be initiated prior to the outage.

5.5 [L] D. Normal Load adjustments during high power conditions to maintain 100% load.

1) If desired to use the "↑ 0.2MW" or "↓ 0.2MW" load adjustment controllers, PERFORM the following:

a. OPEN the desired OSD

☐ ↑ 0.2MW

☐ ↓ 0.2MW

b. VERIFY the desired OSD is open:

☐ 0.2MW INCREASE

☐ 0.2MW REDUCTION

☐ c. SELECT the"0/1" button

☐ d. EXECUTE

e. CLOSE the selected OSD

☐ 0.2MW INCREASE

☐ 0.2MW REDUCTION

2) Normal Load adjustments during high power conditions to maintain 100% load.

☐ a. OPEN the "LOAD TARGET" OSD.

☐ b. VERIFY the open OSD is the "LOAD TARGET".

☐ c. DETERMINE new Load Target Value desired.

☐ d. SELECT the "Blue" Bar and enter the desired LOAD.

☐ e. ACCEPT

☐ f. VERIFY the value in the "Blue Bar" is the desired Load Target. (correct magnitude and direction)

☐ g. EXECUTE

☐ h. VERIFY "Load Target" changes to desired load.

☐ I. CLOSE the "LOAD TARGET" OSD.

5.5 E. Adjusting Voltage with the Main Generator synchronized to the Grid and Voltage Control in Auto to control MVARs/Grid Voltage.

[L]

NOTE: When directed to adjust generator output voltage, actions to comply shall be performed within 5 minutes or provide an explanation to the entity that requested the change.

- ☐ 1) OPEN "GEN VOLTAGE TARGET" OSD.
- ☐ 2) VERIFY the open OSD is “GEN VOLTAGE TARGET”.

CAUTION: If the other Unit is synchronized to the Grid, coordinate with the other Unit to adjust MVARs.

- ☐ 3) CLICK the appropriate RAISE or LOWER "Blue" Arrow.
- ☐ 4) EXECUTE
- ☐ 5) VERIFY MVARs and SWYD Voltage respond in the correct direction.
- ☐ 6) WHEN the desired value is reached, THEN CLICK the "Stop" Button.
- ☐ 7) CLOSE the "GEN VOLTAGE TARGET" OSD.

NOTE:
- Operation with the LEFM calorimetric out of service is covered by TRM 13.3.34, and is not covered by the following guidance.
- The Plant Computer LEFM calorimetric calculation is calculated roughly once per minute. Due to normal fluctuations in the field instrumentation signals, the calculated value of The Plant Computer LEFM calorimetric calculation will vary slightly from minute to minute. As a result, the one-hour average value should be used as the primary basis for evaluating average Rx power level.
- With restoration of the LEFM Calorimetric Program from a failed condition OR reboot of the Plant Computer from a failed condition, all “POWER LEFM” VALUES (1M, 15M, 30M, 1H, 2H, 8H and 12H) on the POWERL Screen will be updated to the instantaneous value calculated by the LEFM Calorimetric Program. The resulting indication will remain as shown for the duration of the applicable time interval, which will not accurately reflect changes in the actual thermal power for the same duration. ODA-308-13.3.34-S01 provides guidance for the restoration of the LEFM.

F. Operational Guidance for operating above 99.00% RTP (3575.88 MWth).

1) No actions are allowed that would intentionally raise core thermal power above 3612.00. Small, short-term fluctuations in power that are not under the direct control of a license reactor operator (e.g., fluctuations caused by secondary-side control valve oscillations, grid fluctuations) are not considered intentional.

2) At no time shall the twelve-hour average calculated power level be allowed to exceed 3612.00 MWth.

5.5 F. 3) Following Rx power adjustments above 99.00% RTP (3575.88 MWth), the value of the Plant Computer LEFM 30 Minute Averaged calorimetric calculation should be monitored frequently for at least 30 minutes. This assessment is made to give the Unit RO reasonable assurance that the two hour average power level will be less than or equal to 3612.00 MWth.

4) At steady-state conditions, adjustments to keep the plant at 3612.00 MWth will be performed at varying frequencies depending upon plant conditions and time in core life. Positive adjustments to Rx power will be based on the current one-hour average power level.

5) Whenever the one-hour average Plant Computer LEFM calorimetric calculation indicates greater than 3612.00 MWth the Unit RO should assess the current calculated Rx power level and trend. The Unit RO should take action, as necessary, to ensure that avg Rx power is trending to a calculated value that is less than or equal to 3612.00 MWth.

6) Closely monitor thermal power during steady state power operation with the goal of maintaining the two-hour thermal power average at or below 3612.00. If the core thermal power average for a 2-hour period is found to exceed 3612.00, timely action shall be taken to ensure that thermal power is less than or equal to 3612.00. The Shift Operations Manager should be notified.

NOTE: A preparatory power reduction is not necessary for evolutions which results in a relatively slow increase in reactivity (e.g. routine dilution, rod step for ΔI control). During evolutions which may slowly increase reactor power, monitoring and adjustments should be performed as necessary to ensure the one hour average power remains < 3612.00 MWth.

7) For pre-planned evolutions that could affect primary or secondary temperatures, pressures or flows:

a. DETERMINE if the evolution is expected to cause a transient increase in reactor power (e.g., TDAFWP run, cycling drip-pots)

b. If the evolution is expected to cause a transient increase in reactor power that will exceed the 3612.00, prudent action based on prior performance or evaluations should be taken to reduce power prior to performing the evolution (i.e. lowering power prior to starting the TDAFWP when it is anticipated that power may exceed 3612.00 is considered prudent action)

5.5 F. 8) The following performance deficiencies should be documented on a Condition Report per STA-421:

a. <u>Raising power with the intent of exceeding 3612.00 MWth for any period of time.</u>

b. Failure to take timely action to lower thermal power to less than or equal to 3612.00 when the two hour average exceeds 3612.00.

c. Permitting the 12 hour average power to exceed 3612.00.

d. Failure to take action prior to a pre-planned evolution that is expected to cause a power increase that will exceed 3612.00 on the two hour average.

G. Electric Grid Support Activities:

1) Main Generator Voltage (345 KV Switchyard)

- MAINTAIN generator voltage as directed by QSE or ONCOR TGM and in accordance with CPNPP Operating procedures.
- Automatic Voltage Regulator (AVR) should be maintained in “AUTO” when the Unit is online and released. If the AVR is transferred to “MANUAL”, then notify the QSE within 10 minutes and maintain voltage as directed.
- When directed to adjust generator output voltage, actions to comply SHALL BE PERFORMED within 5 minutes or provide an explanation to the entity that requested the change.
- The Unit(s) shall not reduce high reactive loading on individual units during abnormal conditions without the consent of the QSE Generation Controller, unless equipment damage is imminent.

2) Logging activities: (Always INCLUDE names of individuals contacted)

- Any change in real (MW) or reactive (MVAR) capability of the unit.
- Non-routine communications to/from Transmission Grid Controller or QSE Generation Controller.
- Voltage change requests - if the voltage change request cannot be performed, then notify the requesting entity and provide the technical justification for not complying with the request. Log the time of notification, the individual’s name notified, and the reason.

5.5 G. 3) QSE Generation Controller notifications:

- Any failure, degradation, or mis-operation of automatic generator protection systems that resulted in, or could have resulted in:

  a) Loss of $\geq$ 1000 MW of generation.**

  b) Sustained switchyard voltage excursions $\geq$ 34.5 KV.**

  c) Major damage to plant components that changes generation output.**

  d) When a generator protective relay mis-operation occurs or has been identified as defined by Corporate Procedure G-3035.**

- Inability to comply with a voltage request. Provide the technical justification for not complying with the request. Log the time of notification, the individual's name notified, and the reason.

- Any planned shutdown due to Technical Specifications or component problems. Then enter a forecasted condition into Nodal GAPS.

- Any change in real MW (25 MWe or more) or reactive (MVAR) power or capability of the unit. If possible, NOTIFY QSE prior to making load changes of more than 10 MWe*

- High reactive loading or reactive oscillations (as soon as possible)

- When a Unit trips offline due to voltage or reactive problems (as soon as possible)

- Any change in power ramp rate capability.

- Any change in the automatic voltage regulator (AVR) status (manual/auto).*

- Luminant plant personnel shall communicate to the unit specific QSE, as soon as practicable, changes in the status and capabilities of the generating unit including, but not limited to:
  a) Unit availability
  b) Material changes in real and reactive output capabilities such as High Sustainable Limit
  c) Unit ramp rate capability

5.5 G. 3)
- Luminant plant personnel shall record unit status and capability changes into the Generation Availability and Plant Status System (GAPS) as soon as practicable. Luminant plant personnel should record this information in the operator log along with the name of the QSE Dispatcher contacted.

  * Notifications are to be made to the QSE Generation Controller within 10 minutes and give restoration status (if known) and have QSE inform ERCOT Operations, input into Nodal GAPS, and a follow-up notification to the Transmission Grid Controller (for their RTCA model update).

  The new corporate procedure has standard phraseology they recommend using such as:

  ""The Automatic Voltage Regulator for Comanche Peak Unit 1 is not in Automatic and is being operated in the Manual mode. The AVR is expected to return to Automatic mode at (time & date). Please communicate this information to ERCOT operations immediately.""

  ""The Automatic Voltage Regulator for Comanche Peak Unit 1 is now back in normal operation in the Automatic mode as of (time). Please communicate this information to ERCOT operations immediately.""

  ** NOTIFY the Duty Manager of this "grid reportable" event for appropriate notifications To the Plant Manager. (STA-501 NR-41)

4) Testing:

- Maximum Generation/Capacity verification should be PERFORMED when requested by the QSE Generation Controller.
- Maximum Reactive Capacity testing per ETP-110A-1 or 2 should be performed:

  a) Biennially per POD schedule.

  b) When requested by the QSE Generation Controller <u>AND</u> coordinated with Operations Management and Work control.

5) General:

- Notifications, GAPS updates, and its respective logging activities should be done in a timely fashion following stabilization of the plant. Off site grid authorities need pertinent CPNPP information to ensure grid stability.
- Hands Off & Grid Notifications - OPGL 41
- Voltage/Frequency issues - ABN-601
- STA-501 ERCOT/NERC/DOE Report NR-41

5.6 **Reducing Turbine Power from 100% to MODE 3**

[C]

> NOTE: Chemistry will specify Demineralizers to be placed in service based on RCS conditions. BTRS or CVCS demineralizers may be used.

> NOTE: For power reductions to approximately 700 MWE, Attachment 6A may be used.

5.6.1 CONTACT Chemistry AND PLACE the specified demineralizers in service per SOP-103A or SOP-106A prior to starting the power reduction.

_______/_______
Initials Date

5.6.2 NOTIFY QSE Generation Controller prior to reducing load.

_______/_______
Initials Date

> NOTE: For power changes greater than 5%, a reactivity plan should be developed using one of the sources below. (Listed in order of preference)
>
> - IF time and resources support generation of a BEACON projection (for a pre-planned power maneuver), THEN contact Core Performance Engineering for support, and utilize the approved results as the reactivity plan.
> - During operation at BOL with a zero or small negative moderator temperature coefficient, very little reactivity feedback will result from changes in RCS temperature. During a shutdown, significant rod movement can occur when relatively small changes in RCS temperature occurs. This could result in large transients in Pressurizer level and RCS pressure. Care should be taken to ensure changes in steam flow and SG level control are done gradually to minimize RCS transients.
> - IF the power change closely matches one of the down-power scenarios available in the Reactivity Briefing Sheets (printed from CHORE), THEN utilize the appropriate reactivity plan (interpolation between values on the Boration Matrix is allowed).
> - IF the above two options are not available or do not fit the current scenario, THEN perform a NDR based reactivity calculation per Attachment 3 or equivalent CHORE output.

[C] 5.6.3 IF Reactor power will be decreased by $\geq$15% within a one hour period,
THEN
NOTIFY Chemistry and Radiation Protection.
(TS SR 3.4.16.2, ODCM 4.11.2.1.1.2, 4.11.2.1.1.3)

_______/_______
Initials Date

NOTE:

- During the initial reduction in power, a combination of control rod insertion and boration should be used to compensate for changes in reactivity due to power defect. This will allow the control rods to be available to compensate for the reactivity due to Xenon following the power reduction.

- Primary plant should lead secondary plant during Main Turbine load changes.

- During a down power, operators should adjust the pots (1-SK-0509B and 1-SK-0509C) to maintain the difference between the FWPT speeds within the desirable range.

- FWPT speed deviation from commanded speed during a normal shutdown may be an indication of binding in a FWPT control valve, guidance for this event is located in ABN-302 Sect. 9.0, FEEDWATER PUMP CONTROL SYSTEM MALFUNCTION.

- The TSE, within the digital turbine control system, is constantly measuring temperatures at critical sections of the turbine and will limit the ramp up/ramp down as deemed necessary by internal stress calculations performed by TSE. If TSE determines that the allowable temperature margin is being approached or exceeded, alarm annunciation will occur and the ramp up/ ramp down will be limited. The following alarms may be received:

  TSE Lower Temp Margin <0
  TSE Lower Temp Margin <20
  TSE Upper Temp Margin <0
  TSE Upper Temp Margin <60
  TSE Lower Margin HP Shaft <0
  TSE Lower Margin HP Shaft <60
  TSE Upper Margin HP Shaft <0
  TSE Upper Margin HP Shaft <60

- While TSE Influence is off, with a TSE fault present, the following limits apply:

  - Turbine load decreases (excluding runbacks) should be limited to a load rate of 10 MW/min while > 400 MWe, THEN limited to 5MW/min while ≤ 400 MWe (during rapid cooldown, a 2-hour HOLD at 400 MWe is required for temperature equalization)

  - Automatic TSE influence to the EHC should not be switched from OFF to ON if any TSE related faults are active.

5.6.4 PERFORM the following steps to reduce Turbine load to approximately 200MW (16%)
or the desired intermediate load:

A. IF desired,
THEN
DETERMINE the amount of boration required to reduce Reactor power to approximately 200 MW or the desired intermediate load using the appropriate currently approved Reactivity Projection.

_______/_______
Initials Date

B. IF desired,
THEN
DETERMINE the rate of boration required to allow slow control rod inward motion as the turbine load decreases, using the appropriate currently approved Reactivity Projection.

_______/_______
Initials Date

C. REFER to Attachment 2 for guidance in controlling AFD during power ramps.

_______/_______
Initials Date

D. INITIATE RCS boration/dilution using SOP-104A.

_______/_______
Initials Date

E. WHEN the following are met: .
1) No TSE alarms are active
2) ENSURE turbine load/speed is matched with target load/speed
THEN
TURN ON TSE Influence.

_______/_______
Initials Date

F. In the “Load Control” Section, SET in the desired unloading rate using the Load Rate Setpoint Controller

_______/_______
Initials Date

NOTE: The load will immediately begin decreasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.

G. In the “Load Control” Section, LOWER the Load Target Setpoint Controller as necessary to obtain 200 MW or the desired intermediate load to control turbine load.

_______/_______
Initials Date

5.6.4 H. IF 1-FK-2239 was throttled open to assist in maintaining HDT level, THEN PERFORM the following:

☐ 1) VERIFY 1-FI-2239, CNDS PUMP DISCH HDR FLO is >14,000 gpm.

☐ 2) ENSURE the 1-FK-2239 toggle switch in TRIP-TO-AUTO ENABLE.

☐ 3) Slowly CLOSE 1-FK-2239, CNDS PMP RECIRC CTRL.

☐ 4) VERIFY 1-ZL-2239, CNDS PMP RECIRC VLV remains closed.

_______/_______
Initials Date

NOTE: ENSURE maintenance set Unit 2 regulator (2-PV-3222) to lead prior to isolating 1-HS-2035 (should be done by Attachment 5).

5.6.5 ISOLATE Extraction Steam to Auxiliary Steam by performing the following:

A. ENSURE ONE of the following:

☐ • Unit 2 is at power, supplying the 50 psig Auxiliary Steam header.

OR

☐ • The 50 psig Auxiliary Steam header is being supplied per SOP-311.

☐ B. CLOSE 1-HS-2035, AUX STM HDR ES SPLY.

☐ C. ENSURE 1-HS-2026, AUX STM HDR ES SPLY D/POT VLV is OPEN.

_______/_______
Initials Date

5.6.6 IF waterhammer in FW Heaters 3A or 3B occurs, the following may be PERFORMED as necessary to isolate the heaters:

A. CLOSE the Extraction Steam Isolation valves to FW Heater 3A and 3B:

- ☐ • 1-HS-2031, FW HTR 3A ES SPLY VLV
- ☐ • 1-HS-2032, FW HTR 3B ES SPLY VLV

B. CLOSE FW Heater 3A and 3B drain valves to the Heater Drain Tank:

- ☐ • 1HD-0049, HTR DRN SYS FW HTR 1-3A OUT TO HTR DRN TK 1-3-2 ISOL VLV
- ☐ • 1HD-0114, HTR DRN SYS FW HTR 1-3B OUT TO HTR DRN TK 1-3-2 ISOL VLV

C. PLACE caution tags on handswitches for Extraction Steam Isolation valve to FW Heater 3A and 3B:

- ☐ • 1-HS-2031, FW HTR 3A ES SPLY VLV
- ☐ • 1-HS-2032, FW HTR 3B ES SPLY VLV

_______/_______
Initials Date

5.6.7 ENSURE the following Main Steam line drain valves are OPEN:

- ☐ • 1MS-0030, MSL 1-01 BEF MSIV D\POT 1-25 DRN ORIF OUT VLV
- ☐ • 1MS-0067, MSL 1-02 BEF MSIV D\POT 1-24 DRN ORIF OUT VLV
- ☐ • 1MS-0102, MSL 1-03 BEF MSIV D\POT 1-23 DRN ORIF OUT VLV
- ☐ • 1MS-0138, MSL 1-04 BEF MSIV D\POT 1-26 DRN ORIF OUT VLV

_______/_______
Initials Date

5.6.8 VERIFY proper rod bank insertion, overlap and sequencing (TS 3.1.6).

A. DETERMINE current FOP and CBO using TDM-102A.

FOP _____ CBO _____

_______/_______
Initials Date

B. CALCULATE where Control Bank C insertion should occur.

CBO + 107 = _______

_______/_______
Initials Date

C. <u>WHEN</u> Control Bank D rods step inward from the position calculated in Step 5.6.8 B. above,
<u>THEN</u>
VERIFY Control Bank C rods begin to step inward from the FOP position determined in Step 5.6.8 A. above.

_______/_______
Initials Date

5.6.9 <u>WHEN</u> Reactor power is below 50%,
<u>THEN</u>
VERIFY 1-PCIP, 1.7, RX ≤50% PWR TURB TRIP PERM P-9 is ON.

_______/_______
Initials Date

5.6.10 VERIFY the permissive P-9 status lights are OFF:

☐ • 1-TSLB-3, 1.9, RX >50% PWR NC-41S

☐ • 1-TSLB-3, 2.9, RX >50% PWR NC-42S

☐ • 1-TSLB-3, 3.9, RX >50% PWR NC-43S

☐ • 1-TSLB-3, 4.9, RX >50% PWR NC-44S

_______/_______
Initials Date

5.6.11 <u>WHEN</u> Reactor power is below 48%,
<u>THEN</u>
VERIFY 1-PCIP, 4.5, RX ≤48% PWR 3-LOOP FLO PERM P-8 is ON.

_______/_______
Initials Date

5.6.12 VERIFY the 3-loop flow permissive P-8 status lights are OFF:

☐ • 1-TSLB-9, 1.7, RX ≥48% PWR NC-41N

☐ • 1-TSLB-9, 2.7, RX ≥48% PWR NC-42N

☐ • 1-TSLB-9, 3.7, RX ≥48% PWR NC-43N

☐ • 1-TSLB-9, 4.7, RX ≥48% PWR NC-44N

________/________
Initials Date

CAUTION: Turbine runback will occur if Turbine power is greater than 700MW. The Turbine will runback at 35%/min to700MW.

NOTE: VERIFY Total Feedwater Flow is <24,000 gpm prior to stopping One MFP.

5.6.13 STOP one Main Feedwater Pump by PERFORMING the following:

A. PERFORM the following:

☐ • ENSURE Turbine power is less than or equal 700 MW.

☐ • ENSURE Total Feedwater Flow <24,000 gpm.

________/________
Initials Date

B. IF at any time during the shutdown of one MFP, the MFP to be left in service starts to oscillate and it is desired,
THEN
PLACE the MFP Master Controller in Manual
AND
STABILIZE the remaining MFP.

• 1-SK-509A, FWPT MASTER SPD CTRL

________/________
Initials Date

C. PLACE the offgoing pump speed controller in MANUAL:

☐ • 1-SK-509B, FWPT A AUTO SPD CTRL

☐ • 1-SK-509C, FWPT B AUTO SPD CTRL

________/________
Initials Date

<u>NOTE</u>:	Plant Computer DFS display provides indication of FWP SDP DEV. SPD DEV is zero when the FW REF (Westinghouse Controller Signal) matches SPD CMD (GE Controller Signal).

5.6.13 D. VERIFY the offgoing Main Feedwater Pump indicates zero deviation between the FW REF and SPD CMD indicated on the DFS display:

☐ • 1-SC-2111B, FWPT A MAN SPD CTRL - FW REF equals SPD CMD

☐ • 1-SC-2112B, FWPT B MAN SPD CTRL - FW REF equals SPD CMD

_______/_______
Initials Date

E. DEPRESS the offgoing Main Feedwater Pump MANUAL pushbutton.

☐ • 1-HS-2111A, FWPT A SPD CTRL MODE SELECT

☐ • 1-HS-2112A, FWPT B SPD CTRL MODE SELECT

_______/_______
Initials Date

F. PERFORM the following to reduce the offgoing Main Feedwater Pump speed:

<u>NOTE</u>:	In MODE 1 or 2 with only one MFP capable of supplying flow to the SGs <u>AND</u> the offgoing MFP is <u>NOT</u> tripped, TS 3.3.2 Condition J is not met (Trip channels from offgoing MFP to each Motor Driven AFW Pump is inoperable). (Reference Limitation 4.1.17)

☐ 1) INITIATE a LCOAR for TS 3.3.2 Condition J for two inoperable MFP trip channels (one to each MD AFW Pump).

☐ 2) Slowly REDUCE FWPT A/B MAN SPD CTRL (1-SC-2111B or 1-SC-2112B),
<u>WHILE</u> VERIFYING the remaining pump speed and flow increases.

☐ 3) VERIFY FWP A/B RECIRC VLV (1-ZL-2289 or 1-ZL-2290) begins to open when selected Main Feedwater Pump flow is approximately 5000 gpm.

_______/_______
Initials Date

5.6.13 G. WHEN the Plant Computer DFS display, SPD CMD is at zero for the selected FWP,
THEN
TRIP the MFW pump by pushing the FWPT TRIP pushbutton:

- ☐ ● FEED PUMP TURBINE A SPD CMD is zero
- ☐ ● 1-HS-2111C, FWPT A TRIP
- ☐ ● FEED PUMP TURBINE B SPD CMD is zero
- ☐ ● 1-HS-2112C, FWPT B TRIP

_______/_______
Initials Date

H. ENSURE FWP SUCT FLO and FWP SUCT PRESS remain within normal bands on the running pump.

_______/_______
Initials Date

I. VERIFY the following valves for the selected Main Feedwater Pump are CLOSED:

- ☐ ● 1-ZL-2111A, FWPT A LP STOP VLV
- ☐ ● 1-ZL-2111B, FWPT A HP STOP VLV
- ☐ ● 1-ZL-2289, FWP A RECIRC VLV
- ☐ ● 1-HS-2109, FWPT A DISCH VLV
- ☐ ● 1-ZL-2112A, FWPT B LP STOP VLV
- ☐ ● 1-ZL-2112B, FWPT B HP STOP VLV
- ☐ ● 1-ZL-2290, FWP B RECIRC VLV
- ☐ ● 1-HS-2110, FWPT B DISCH VLV

_______/_______
Initials Date

J. ENSURE the tripped Main Feedwater Pump drains (1-CB-08) are OPEN:

- ☐ ● 1-HS-2168, FWPT A HP STOP VLV AFT SEAT DRN VLV
- ☐ ● 1-HS-2170, FWPT A LP STOP VLV AFT SEAT DRN VLV
- ☐ ● 1-HS-2173, FWPT B HP STOP VLV AFT SEAT DRN VLV
- ☐ ● 1-HS-2175, FWPT B LP STOP VLV AFT SEAT DRN VLV

_______/_______
Initials Date

5.6.13 K. EXIT LCOAR for TS 3.3.2 Condition J for two inoperable MFP trip channels (one to each MD AFW Pump).

_______/_______
Initials Date

CAUTION:	It is normally preferred to place the pumps on the turning gear. Windmilling the pumps can damage the seal and wear ring, causing failure of internal components. If it is decided to windmill the pumps, minimize the time on windmill operations and ensure casing ΔT requirements are met. The turning gear rotates at a slow speed which allows any bows in the turbine shaft to be removed. Windmilling rotates at a faster speed and can actually set any bow in the turbine shaft.

L. VERIFY the Main Feedwater Pump turning gear engages (1-ZL-2111I or 1-ZL-2112I)
OR
ALIGN the pump to windmill per SOP-302A.

_______/_______
Initials Date

M. IF this is not a refueling outage
AND
It is desired to keep Heaters 5 and 6 full.
THEN
OPEN the following valves:

- 1CO-0090, FW HTR 1-5A/1-6A CNDS IN VLV 2611A EQUAL BYP VLV
- 1CO-0091, FW HTR 1-5B/1-6B CNDS IN VLV 2612A EQUAL BYP VLV
- 1CO-0110, FW HTR 1-5A/1-6A CNDS OUT VLV 2611B EQUAL BYP VLV
- 1CO-0111, FW HTR 1-5B/1-6B CNDS OUT VLV 2612B EQUAL BYP VLV

_______/_______
Initials Date

NOTE: Operation with Condenser vacuum in the Not Permissible area is limited to ≤ 5 minutes per event and 300 minutes during total working life of the last blade row.

5.6.14 IF during down power Condenser Vacuum falls below 27" Hg,
THEN
MONITOR the Back Pressure Limit Display.

_______/_______
Initials Date

A. IF the cursor is in the NOT PERMISSIBLE Area,
THEN
TAKE one or more actions to reduce stresses on LP turbine blades as follows:

1) MAXIMIZE Condenser vacuum:

☐ • START all available CEVs.

☐ • START all available Circ Water Pumps.

☐ 2) DECREASE turbine load at a rate ≥60 MW/min until vacuum has been restored to the PERMISSIBLE WITHOUT LIMIT area. (no time limit)

☐ 3) REDUCE turbine load until vacuum is restored to the PERMISSIBLE WITHOUT LIMIT area. (5 minutes or less)

_______/_______
Initials Date

5.6.15 WHEN Turbine power is below 40%,
THEN
VERIFY 1-PCIP, 1.3, AMSAC BLK TURB <40% PWR C-20 annunciator is ON.

_______/_______
Initials Date

NOTE: At ≥ 40%, Main Steamline N-16 Radiation monitors satisfy STA-732 primary-to-secondary leakage detection requirements. The Condenser Off-Gas Radiation monitor provides a reliable backup indication for primary-to-secondary leakage. During Unit shutdown when the Condenser Off-Gas Radiation monitor is operable, Main Steamline N-16 Radiation monitor channel alarms may be disabled at a power level convenient to support manpower availability.

5.6.16 DISABLE the channel alarms for all Main Steamline N-16 Radiation monitors per SOP-706:

☐ • N16-174 (1-RE-2325A, MSL 1-01 SG LEAK RATE MONITOR DETECTOR)

☐ • N16-175 (1-RE-2326A, MSL 1-02 SG LEAK RATE MONITOR DETECTOR)

☐ • N16-176 (1-RE-2327A, MSL 1-03 SG LEAK RATE MONITOR DETECTOR)

☐ • N16-177 (1-RE-2328A, MSL 1-04 SG LEAK RATE MONITOR DETECTOR)

_______/_______
Initials Date

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-003A
POWER OPERATIONS	REVISION NO. 30 **CONTINUOUS USE**	PAGE 119 OF 226

NOTE:
- The Main Feedwater Pump is NOT required to be placed on the turning gear for it to be considered secured.
- Excessive condensate flow through the LP heaters may cause a high level in the shell side of heaters and subsequent automatic isolation of extraction steam. Once extraction steam is isolated to the LP Heaters, Condensate cools the LP heaters and shell pressure decreases. As the shell pressure drops, steam from the heater drain tank travels up the pipe toward the LP heater. Meanwhile the condensed steam traveling up the pipe meets the subcooled water resulting in waterhammer in the drain lines from the number 3 FW heaters. Operating experience has shown that initiation of a MFP windmilling at the same time Heater Drain forward flow is being reduced can result in ES isolation to the number 3 FW heaters which will result in counterflow waterhammer between Heater Drain Tanks and LP Heaters. Windmilling the MFP should NOT be performed at the same time as stopping Heater Drain Pumps.

5.6.17 A. IF a short duration downpower is planned,
THEN
PERFORM the following to maintain normal drain lines full.

1). ENSURE the following valves are in AUTO:

- ☐ • 1-LK-2709, MSR A SEP DRN TK ALT LVL CTRL
- ☐ • 1-LK-2713, MSR B SEP DRN TK ALT LVL CTRL

_______/_______
Initials Date

2). PLACE the following valves in MANUAL and CLOSED. (OBSERVE Alternates responding while closing)

- ☐ • 1-LK-2712, MSR B SEP DRN TK NORM LVL CTRL
- ☐ • 1-LK-2708, MSR A SEP DRN TK NORM LVL CTRL

_______/_______
Initials Date

NOTE:
- HDPs may be left running on recirc for a downpower or forced outage.
- IF HDPs will be running on recirc for >24hrs, THEN Plant Reliability should assess pump vibration (Reference EV-CR-2013-007250).

5.6.17 ☐ B. WHEN a Main Feedwater Pump has been secured,
THEN
PERFORM the following:

1) IF desired to STOP HDPs,
THEN
PERFORM SOP-308A for Shutdown of Both HDPs ______/______
Initials Date

2) IF HDPs will be left running on recirc >24hrs,
THEN
NOTIFY Plant Reliability to assess pump vibration . ______/______
Initials Date

☐ C. IF a short duration downpower is planned,
THEN
OPEN 1-HS-2611/12, FW HTR 5A & 6A/5B & 6B BYP VLV. ______/______
Initials Date

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-003A
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CAUTION: Anytime the Condensate Recirc Valve is throttled, MFP Suction Pressure should be monitored and kept above 320 psig to prevent inadvertent opening of the LP Heater Bypass Valve.

NOTE:

- Continued operation of both condensate pumps at low flow may cause the low pressure feedwater heater and drain cooler relief valves to lift. Relief valve set pressures are 600 psig. 1-FK-2239, CNDS PMP RECIRC VLV, should be operated as needed per ALM-0082A to prevent lifting the relief valves.
- Any change in Condensate pump configuration affects operation of the Condensate Polishing System which may need Rad Waste Operator attention.
- A minimum flow rate of 3000 gpm per operating Condensate Pump shall be maintained.
- Prior to stopping one Condensate Pump, verify condensate flow approximately 12,000 gpm. A maximum flow rate of 14,700 gpm per operating Condensate Pump shall NOT be exceeded.

5.6.18 IF it is desired to stop one Condensate Pump
AND
one MFW Pump and both Heater Drain Pumps have been shutdown,
THEN
PERFORM the following:

☐ A. ENSURE 1-FK-2239, CNDS PMP RECIRC CTRL is Throttled as necessary to maintain proper flow and pressure requirements for Cond Pump(s).

☐ B. STOP one Condensate Pump AND ENSURE its associated Discharge Valve goes closed.

_______/_______
Initials Date

5.6.19 ENSURE the 1-FK-2239 toggle switch in TRIP-TO-AUTO ENABLE. _______/_______
Initials Date

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-003A
POWER OPERATIONS	REVISION NO. 30 **CONTINUOUS USE**	PAGE 122 OF 226

NOTE:
- 1-HV-2419A-D and 1-HV-2420A-D open automatically on turbine trip.
- Associated drip pot alarm response not required for the following step.

5.6.20 IF Turbine cooldown is desired,
THEN
OPEN the following valves as needed:

- ☐ • 1-HS-2417, HP CTRL VLV 1●4 BEF SEAT DRN VLV
- ☐ • 1-HS-2418, HP CTRL VLV 3/4 AFT SEAT DRN VLV
- ☐ • 1-HS-2419, TURB SIDE XOVER DRN VLV
- ☐ • 1-HS-2420, MSR SIDE XOVER DRN VLV
- ☐ • 1-HS-2432/5, MSL STRN D/POT VLV
- ☐ • 1-HS-2436/9, MSL TO MSR D/POT VLV
- ☐ • 1-HS-2011, FW HTR 1A ES SPLY D/POT VLV
- ☐ • 1-HS-2013, FW HTR 1B ES SPLY D/POT VLV
- ☐ • 1-HS-2015, FW HTR 2A ES SPLY D/POT VLV
- ☐ • 1-HS-2017, FW HTR 2B ES SPLY D/POT VLV
- ☐ • 1-HS-2019, FW HTR 3A ES SPLY D/POT VLV
- ☐ • 1-HS-2021, FW HTR 3B ES SPLY D/POT VLV
- ☐ • 1-HS-2023, FW HTR 4A ES SPLY D/POT VLV
- ☐ • 1-HS-2025, FW HTR 4B ES SPLY D/POT VLV

/
Initials Date

5.6.21 IF a Reactor trip is planned,
THEN
NOTIFY Chemistry and Radiation Protection to initiate sampling requirements of ODCM 4.11.2.1.1.2 and 4.11.2.1.1.3.

/
Initials Date

5.6.22 CONTACT Prompt Team to ensure a Channel Operational Test on Source Range Channels per INC-7381A and INC-7382A has been performed within the previous 184 days (RT#501485 and RT#500297) (TS SR 3.3.1.7.5).

- ☐ ● INC-7381A performed (RT#501485, Loop N-31 COT)
- ☐ ● INC-7382A performed (RT#500297, Loop N-32 COT)

_______/_______
Initials Date

[C] 5.6.23 ENSURE the Feedwater Isolation Valve heaters are in service as follows:

A. ENSURE the following breakers are ON:

- ☐ ● 1EB2-3/3BL/BKR, SG 1-01 FW ISOL VLV 1-HV-2134 HEAT TRACE CTRL PNL 1-01 SPLY BREAKER
- ☐ ● 1EB2-3/3BR/BKR, SG 1-02 FW ISOL VLV 1-HV-2135 HEAT TRACE CTRL PNL 1-02 SUPPLY BREAKER
- ☐ ● 1EB2-3/3DR/BKR, SG 1-03 FW ISOL VLV 1-HV-2136 HEAT TRACE CTRL PNL 1-03 SUPPLY BREAKER
- ☐ ● 1EB2-3/3FL/BKR, SG 1-04 FW ISOL VLV 1-HV-2137 HEAT TRACE CTRL PNL 1-04 SUPPLY BREAKER

_______/_______
Initials Date

> <u>NOTE</u>: Temperature is controlled on one side of the valves while temperature readings from opposite side of valves are recorded. Experience has shown that a Heater Control setting of 160°F will maintain valve temperature at the surveilled temperature indicator approximately 110°F.

B. ENSURE Heater Control is set at >160°F <u>OR</u> as necessary to maintain recorded
temperature above 110°F. (SFGD 852, FWIV ROOM):

- ☐ ● CP1-HTCPLV-01, SG 1-01 FW ISOLATION VALVE 2134 HEAT TRACE CONTROL PANEL 1-01
- ☐ ● CP1-HTCPLV-02, SG 1-02 FW ISOLATION VALVE 2135 HEAT TRACE CONTROL PANEL 1-02
- ☐ ● CP1-HTCPLV-03, SG 1-03 FW ISOLATION VALVE 2136 HEAT TRACE CONTROL PANEL 1-03
- ☐ ● CP1-HTCPLV-04, SG 1-04 FW ISOLATION VALVE 2137 HEAT TRACE CONTROL PANEL 1-04

_______/_______
Initials Date

5.6.24 NOTIFY Prompt Team of the estimated time for Reactor Trip to allow performance of the following:

☐ • INC-4015A, to set IR compensating voltage (20 to 60 minutes after trip), if scheduled.

☐ • INC-7669A, to take N-16 background measurements (4 to 8 hours after Trip) if required (TS SR 3.3.1.7.6 and 3.3.1.7.7).

☐ • Vent 1-FT-0183, UNIT 1 CVCS EMERGENCY BORIC ACID TO CHARGING PUMP FLOW TRANSMITTER.

_______/_______
Initials Date

5.6.25 IF RCS will be opened for maintenance
OR
degassing is required,
THEN
PERFORM the following:

A. IF RCS activity (Xe 133) is NOT within the specifications required by Chemistry and Radwaste,
THEN
ENSURE RCS purge via the VCT to gas decay tanks per RWS-201 is in progress.

_______/_______
Initials Date

B. ENSURE Chemistry has ALIGNED Pressurizer vapor (steam) space sample to continuously purge to the VCT per COP-101A.

_______/_______
Initials Date

> NOTE: When Pressurizer vapor (steam) space sample is aligned to purge to the VCT, Vent Stack radiation indication may be used to detect primary sample relief actuation.

C. MONITOR Vent Stack radiation indication during purge of the Pressurizer vapor (steam) space sample to the VCT.

_______/_______
Initials Date

> NOTE: Using 1-HS-4165A, PSS ISOL VLV to isolate Pressurizer vapor (steam) space purge to the VCT also isolates other sample paths that may be aligned (Reference 1-MLB-1A2: 1-HV-4165, 4166, 4168, 4169, 4171, 4172, 4173, 4174, 4182, 7312, 5556, 5558, 5560).

5.6.25 D. IF an unexplained increase in Vent Stack radiation is observed and it is suspected that the primary sample relief has actuated, THEN PERFORM one of the following:

☐ • PLACE 1-HS-4165A, PSS ISOL VLV in CLOSE
AND
NOTIFY Chemistry,

OR

☐ • CONTACT Chemistry to STOP Pressurizer vapor (steam) space purge to VCT.

_______/_______
Initials Date

> NOTE: Verification of adequate Shutdown Margin prior to MODE 3 entry will be satisfied by the following step. Following MODE 3 entry, RCS boron concentration shall NOT be intentionally decreased and an RCS cooldown shall NOT be intentionally initiated until adequate Shutdown Margin has been verified.

5.6.26 Within 12 hours prior to entering MODE 3, DOCUMENT Control Bank Insertion Limits have been verified per OPT-102A (TS 3.1.6).

_______/_______
Initials Date

> NOTE:
> - The transfer of the 6.9 KV normal buses from 1UT to 1ST will occur when the main generator output breakers trip following the Rx trip if not performed in the following step. This is the preferred method.
> - The transfer of the 6.9 KV normal buses from 1UT to 1ST can be performed at or below 90% RTP during a rapid downpower (transition to mode 3 in one hour or less) with Operations Management approval.

5.6.27 IF desired,
THEN
TRANSFER the 6.9 KV normal buses from 1UT to 1ST per SOP-603A.

_______/_______
Initials Date

5.6.28 BLOCK the HIGH FLUX AT SHUTDOWN alarm on both Source Range drawers.

- ☐ • N-31, HIGH FLUX AT SHUTDOWN
- ☐ • N-32, HIGH FLUX AT SHUTDOWN

_______/_______
Initials Date

5.6.29 IF desired to resume Turbine Load increase,
THEN
GO TO Attachment 13.

_______/_______
Initials Date

5.6.30 IF desired to reduce Turbine power to approximately 5%,
THEN
GO TO Section 5.7.

_______/_______
Initials Date

5.6.31 IF desired to cooldown the Turbine WHILE maintaining Reactor power approximately 16%,
THEN
GO TO Section 5.8.

_______/_______
Initials Date

NOTE: The Main Generator should be disconnected within 1 hour of the trip when practical.

5.6.32 NOTIFY Transmission Grid Management (TGM) of the planned trip AND that Glen Rose Transmission personnel will be required for Switching and Tagging.

_______/_______
Initials Date

5.6.33 PERFORM pre-evolution brief for reactor trip using Attachment 9. _______/_______
Initials Date

CAUTION: Anytime the Condensate Recirc Valve is throttled, MFP Suction Pressure should be monitored to prevent inadvertent opening of the LP Heater Bypass Valve.

NOTE: The next Step will provide added protection for the Condensate pump when the Rx is tripped.

5.6.34 ENSURE 1-FK-2239, CNDS PMP RECIRC CTRL is OPEN.

_______/_______
Initials Date

NOTE:
- Plant Computer point P5446A, FW STM FLOW SETPOINT is the calculated DP setpoint for FW Header and MS Header for 1-SK-509A, FWPT MASTER SPD CTRL.
- Plant Computer point U5002A, FW - MS HEADER DP is the actual DP value for FW Header and MS Header.
- Plant Computer point U5003A, DELTA PROGRAM - ACTUAL DP provides indication of the difference between the programmed differential pressure and actual differential pressure.
- Plant Computer DFS Screen can be used to determine if MFP speed matches Speed Command prior to placing Master Speed Controller in AUTO.

5.6.35 IF 1-SK-509A, FWPT MASTER SPD CTRL is in MANUAL,
THEN
PERFORM the following:

A. IF the running MFP Speed Controller in Manual (1-SK-509B or 1-SK-509C),
THEN
PERFORM the following:

☐ 1) PLACE 1-SK-509A, FWPT MASTER SPD CTRL in AUTO

2) ADJUST Feedwater Pump speed in MANUAL using the running MFP Speed Controller to maintain Programed FW - MS Header D/P.

☐ • 1-SK-509B FWPT A AUTO SPD CTRL

☐ • 1-SK-509C FWPT B AUTO SPD CTRL

3) WHEN FWP DISCH HDR D/P is near the Programed FW - MS Header D/P,
THEN
PLACE the running FWPT (A or B) AUTO SPD CTRL in AUTO:

☐ • 1-SK-509B FWPT A AUTO SPD CTRL

☐ • 1-SK-509C FWPT B AUTO SPD CTRL

☐ 4) GO TO Step 5.6.35 C.

_______ / _______
Initials Date

5.6.35 B. IF the running MFP Speed Controller is in Auto (1-SK-509B or 1-SK-509C),
THEN
PERFORM the following:

☐ 1) ADJUST Feedwater Pump speed in MANUAL using 1-SK-509A, FWPT MASTER SPD CTRL to maintain Programed FW - MS Header D/P.

☐ 2) WHEN FWP DISCH HDR D/P is near the Programed FW - MS Header D/P,
THEN
PLACE 1-SK-509A, FWPT MASTER SPD CTRL in AUTO.

_______/_______
Initials Date

C. VERIFY the following parameters:

☐ • Program differential pressure is maintained between 1-PI-508, FWP DISCH HDR PRESS and 1-PI-507, MS HDR PRESS. CTRL

☐ • FWP SUCT FLOW AND FWP SUCT PRESS remains within normal bands.

_______/_______
Initials Date

NOTE:
- Performance of ODA-108, Post RPS/ESF Actuation Evaluation, is NOT required following a planned trip performed in accordance with this procedure. However, the person performing the evaluation of the Planned Trip Data Collection shall be Shift Technical Advisor (STA) qualified or an Engineer trained in Transient Analysis.
- The loss of Reactive Load (MVAR) on the Main Generator at the time of turbine trip will affect Reactive Load (MVAR) on the opposite Unit.

5.6.36 ESTABLISH Planned Trip Data Collection as required per Attachment 8.

_______/_______
Initials Date

5.6.37 WHEN all steps in the section have been initiated or completed, as required, THEN PERFORM the following steps:

☐ A. OBTAIN the Shift Manager approval, AND

☐ B. MANUALLY trip the reactor, AND

☐ C. PROCEED to EOP-0.0A THEN TRANSITION to IPO-005A OR IPO-007A AND IPO-009A, when directed.

NOTE:
- The following step will initiate Emergency Boration in preps for Cooldown per IPO-005A. The Emergency Boration will be reverified and completed in IPO-005A.
- Step 5.6.37D should be performed by an operator not associated with EOP-0.0A response.

D. IF desired to initiate Emergency Boration, THEN PERFORM the following:

☐ 1) ENSURE a charging pump is running.

CAUTION: If two boric acid transfer pumps are used in the following steps, Unit 2 boric acid transfer pumps are placed in PULL OUT and auto makeup to the VCT is turned off. This is because two pumps shall not be run on one boric acid storage tank. If blended flow or boration becomes necessary for Unit 2, then one of the Unit 1 pumps is stopped to make the like pump available on Unit 2.

2) IF desired to run two boric acid transfer for boration, THEN NOTIFY **Unit 2** to perform the following:

☐ a. PLACE 43/2-MU, RCS MU MODE SELECT in OFF.

b. PLACE the boric acid transfer pumps in PULL OUT.

☐ • 1/2-APBA1, BA XFER PMP 1

☐ • 1/2-APBA2, BA XFER PMP 2

3) START the desired boric acid transfer pump(s)

☐ • 1/1-APBA1, BA XFER PMP 1

☐ • 1/1-APBA2, BA XFER PMP 2

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5.6.37 D.

☐ 4) OPEN 1/1-8104, EMER BORATE VLV AND RECORD flow & time

Time______ 1-FI-183A, EMER BORATE FLO_____ gpm

☐ 5) CYCLE 1/1-LCV-112A, VCT LVL CTRL OR PLACE in AUTO as necessary to maintain desired VCT level. ________/________ Initials Date

. E. VERIFY EITHER of the following:

☐ RCS Boration rate greater than 30 GPM
OR
☐ Shutdown margin shows at least 30 ppm excess boron. ________/________ Initials Date

F. IF CVCS Demins have been previously prepared by SOP-103A,
THEN
ENSURE 1/1-TCV-0129 is in the DEMIN position. ________/________ Initials Date

G. 1) IF RCS boration is secured prior to CVCS Mixed Bed outlet boron being verified greater than the NDR required value,
THEN
BYPASS the demins by placing 1/1-TCV-0129, LTDN DIVERT VLV, in the VCT position. ________/________ Initials Date

2) WHEN RCS boration is resumed,
THEN
PLACE 1/1-TCV-0129, LTDN DIVERT VLV, in the DEMIN position. ________/________ Initials Date

☐ H. FILE this procedure per ODA-104. ________/________ Initials Date

COMMENTS: ____

____

____

____

IPO-003A Power Reduction satisfactorily completed:____________________/__________
SHIFT MANAGER DATE

5.7 **Plant Shutdown To 5% Turbine Power**

5.7.1 PERFORM the following steps to reduce Turbine load to approximately 160 MW (14%):

A. IF Reactor power will be decreased by $\geq$15% within a one hour period,
THEN
NOTIFY Chemistry and Radiation Protection.
(TS SR 3.4.16.2, ODCM 4.11.2.1.1.2, 4.11.2.1.1.3).

_______/_______
Initials Date

B. IF desired,
THEN
CALCULATE the amount of boration/dilution required to reduce Reactor power to approximately 14%.

_______/_______
Initials Date

C. IF desired,
THEN
CALCULATE the rate of boration/dilution required to allow slow control rod inward motion as the turbine load decreases.

_______/_______
Initials Date

D. REFER to Attachment 2 for controlling AFD during power decreases.

_______/_______
Initials Date

E. NOTIFY the QSE Generation Controller of intent to decrease turbine load.

_______/_______
Initials Date

F. INITIATE RCS boration using SOP-104A.

_______/_______
Initials Date

G. In the "Load Control" Section, SET in the desired unloading rate using the Load Rate Setpoint Controller.

_______/_______
Initials Date

H. WHEN the following are met:
.
1) No TSE alarms are active

2) ENSURE turbine load/speed is matched with target load/speed
THEN
TURN ON TSE Influence.

_______/_______
Initials Date

NOTE:

- The Rod Control System may remain in AUTO as Turbine load continues to decrease. If rod withdrawal is required below 15% Turbine power, MANUAL rod control should be utilized to maintain Tave approximately equal to Tref.
- The load will immediately begin decreasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
- The LOAD Target may be incrementally lowered to control rate of Turbine power decrease.
- During operation at BOL with a zero or small negative moderator temperature coefficient, very little reactivity feedback will result from changes in RCS temperature. During a shutdown, significant rod movement can occur when relatively small changes in RCS temperature occurs. This could result in large transients in Pressurizer level and RCS pressure. Care should be taken to ensure changes in steam flow and SG level control are done gradually to minimize RCS transients.

5.7.1 I. In the “Load Control” Section, LOWER the Load Target Setpoint Controller as necessary to obtain 160 MW or the desired intermediate load to control turbine load.

_______/_______
Initials Date

J. IF flow control issues occur,
THEN
PLACE SG FW BYP CTRL VLVs in service per Step 5.7.3

_______/_______
Initials Date

K. IF desired to raise turbine load,
THEN
PERFORM the following:

a) IF SG FW BYP CTRL VLVs are in service,
THEN
PLACE SG FW FLO CTRL VLVs in service per Step 5.1.37.

_______/_______
Initials Date

b) GO TO Section 5.3, Step 5.3.1

_______/_______
Initials Date

5.7.2 WHEN Turbine load is approximately 170 MW (15%),
THEN
TRANSFER the Steam Dump System to the Steam Pressure mode as follows:

☐ A. ENSURE 1-PK-507, STM DMP PRESS CTRL is in MANUAL.

☐ B. MATCH 1-PK-507, STM DUMP PRESS CTRL demand to 1-UI-500, STM DMP DEMAND.

☐ C. VERIFY 1-PCIP, 1.4, CNDSR AVAIL STM DMP ARMED C-9 is ON.

☐ D. ENSURE BOTH STM DMP INTLK SELECT switches are ON.

☐ E. PLACE 43/1-SD, STM DMP MODE SELECT in STM PRESS AND VERIFY proper response of steam dump valves.

☐ F. ENSURE 1-PK-507, STM DMP PRESS CTRL set to 6.86.

☐ G. PLACE 1-PK-507, STM DMP PRESS CTRL in AUTO.

☐ H. VERIFY 1-PI-507, MS HDR PRESS is approximately 1092 psig.

_________ / _________
Initials Date

5.7.3 PERFORM the following steps to place the FW BYP CTRL VLVs in service:

☐ A. OPERATE the SG FW BYP CTRL valves in MANUAL as required.

☐ B. OPERATE the SG FW FLO CTRL valves in MANUAL as required.

> NOTE: Manipulations of the Feedwater Bypass Control Valves and Feedwater Control Valves should be performed on one feedwater line at a time. SG levels should be continuously monitored while transferring control to the Feedwater Bypass Control Valves.

☐ C. Slowly OPEN the FW BYP CTRL Valve WHILE CLOSING the FW FLO CTRL Valve.

☐ D. IF desired,
THEN
PLACE the SG FW BYP CTRL in AUTO.

☐ E. REPEAT Steps 5.7.3 C and D to close each FW FLO CTRL valve.

☐ F. ENSURE ALL FW FLO CTRL VLVs are in MANUAL AND CLOSED.

☐ G. MAINTAIN SG levels between 60% and 75%.

_________ / _________
Initials Date

5.7.4 Using manual Rod Control or RCS boration, MAINTAIN Tave within 1°F of Tref.

_______/_______
Initials Date

> <u>NOTE</u>:
> - The load will immediately begin decreasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
> - The LOAD Target may be incrementally lowered to control rate of Turbine power decrease.

5.7.5 In the “Load Control” Section, LOWER the Load Target Setpoint Controller as necessary to obtain 60 MW (5%).

_______/_______
Initials Date

> <u>NOTE</u>: Rod shadowing may cause IR NIS to read significantly higher than PR NIS. This may result in unblocking the IR Overpower Trips, with the trips NOT reset, as PR NIS lowers below the P-10 reset point. If this condition is anticipated, based on the mismatch between PR and IR indications, boration may be required to cause rods to move outward to eliminate rod shadowing.

5.7.6 <u>WHEN</u> Reactor power is below 25%,
<u>THEN</u>
VERIFY the following are OFF:

- ☐ 1-TSLB-6, 1.2, "IR FLUX HI NC-35F"
- ☐ 1-TSLB-6, 2.2, "IR FLUX HI NC-36F"
- ☐ 1-TSLB-6, 1.6, "PR FLUX SETPT LO NC-41P"
- ☐ 1-TSLB-6, 2.6, "PR FLUX SETPT LO NC-42P"
- ☐ 1-TSLB-6, 3.6, "PR FLUX SETPT LO NC-43P"
- ☐ 1-TSLB-6, 4.6, "PR FLUX SETPT LO NC-44P"

_______/_______
Initials Date

5.7.7 <u>WHEN</u> Turbine load has decreased below 115 MW (10%),
<u>THEN</u>
VERIFY 1-PCIP, 4.6, "TURB $\leq$10% PWR P-13" is ON.

_______/_______
Initials Date

5.7.8 WHEN Reactor power is below 10% (3/4 PR channels),
THEN
ENSURE the following:

A. The following annunciators and monitor lights are as indicated:

- ☐ • 1-PCIP, 1.6, "RX ≥10% PWR P-10" is OFF
- ☐ • 1-ALB-6D, 1.1, "SR HI VOLT FAIL" is ON
- ☐ • 1-PCIP, 1.2, "IR TRN A RX TRIP BLK" is OFF
- ☐ • 1-PCIP, 2.2, "IR TRN B RX TRIP BLK" is OFF
- ☐ • 1-PCIP, 3.2, "PR TRN A LO SETPT RX TRIP BLK" is OFF
- ☐ • 1-PCIP, 4.2, "PR TRN B LO SETPT RX TRIP BLK" is OFF
- ☐ • 1-TSLB-9, 1.8, "RX ≥10% PWR NC-41M" is OFF
- ☐ • 1-TSLB-9, 2.8, "RX ≥10% PWR NC-42M" is OFF
- ☐ • 1-TSLB-9, 3.8, "RX ≥10% PWR NC-43M" is OFF
- ☐ • 1-TSLB-9, 4.8, "RX ≥10% PWR NC-44M" is OFF

/
Initials Date

B. ENSURE 1-PCIP, 2.4, "LO TURB PWR ROD WTHDRWL BLK C-5" is ON.

/
Initials Date

C. IF all bistable lights are NOT OFF,
THEN
REFER to ABN-703.

/
Initials Date

5.7.9 WHEN the P-10 annunciator is OFF and P-13 annunciator is ON,
THEN
ENSURE 1-PCIP, 3.5, "RX & TURB $\leq$10% PWR P-7" is ON. ________/________
Initials Date

5.7.10 IF desired to trip the reactor from this power level,
THEN
GO TO Step 5.6.32. ________/________
Initials Date

5.7.11 IF desired to raise plant power,
THEN
GO TO Step 5.1.35. ________/________
Initials Date

COMMENTS: ____

____

____

IPO-003A Power Reduction satisfactorily completed:________________/________
SHIFT MANAGER DATE

5.8 **TURBINE COOLDOWN**

This section performs a cooldown of the turbine by reducing turbine load while maintaining Reactor power at approximately 15% and constant steam flow. Reducing turbine temperatures allows turbine work to begin sooner in the outage. The following considerations apply during the use of this section.

NOTE:
- The T_{AVE} Deviation meter will be unreliable due to the Reactor power - Turbine power mismatch. T_{AVE} should be maintained using T_{AVE} meters and TDM-301A.
- Reduced feedwater temperatures at lower turbine loads results in lower RCS Tcold temperatures which introduces added inaccuracies to NIS indications. N16 should be monitored for accurate power indication.
- Control Rod withdrawal in MANUAL will be required to maintain constant RCS temperature, Reactor power and Feedwater flow.

NOTE: Turbine cooldown termination criteria:
- Turbine Casing ΔT approaching 50°F absolute (Plant Computer Group Display LPTDIFF)
- Approximately 90 minutes at 60 MW Turbine power
- Turbine cooldown rate slows (TSE Margin Display: Casing Temperature)
- Per Shift Manager direction

NOTE: Experience indicates that Turbine Casing differential temperature may increase while Turbine is at 60 MW. Plant Computer Group Display LPTDIFF should be closely monitored.

5.8.1 Operations Management has approved the use of this section. ________/________
Initials Date

5.8.2 PERFORM pre-evolution brief for reactor trip using Attachment 9.________/________
Initials Date

NOTE: Performance of ODA-108, Post RPS/ESF Actuation Evaluation, is NOT required following a planned trip performed per this procedure. However, the person performing the evaluation of the Planned Trip Data Collection shall be Shift Technical Advisor (STA) qualified or an Engineer trained in Transient Analysis.

5.8.3 ESTABLISH Planned Trip Data Collection as required per Attachment 8. ________/________
Initials Date

NOTE: The Main Generator should be disconnected within 1 hour of the trip when practical.

5.8.4 NOTIFY Transmission Grid Management (TGM) of the planned trip AND that Glen Rose Transmission personnel will be required for Switching and Tagging.

_______ / _______
Initials Date

5.8.5 WHEN Reactor power is approximately 15%,
THEN
ENSURE Rod Control in MANUAL.

_______ / _______
Initials Date

5.8.6 ENSURE T_{AVE} is correct for current Reactor power per TDM-301A.

_______ / _______
Initials Date

5.8.7 To set Steam Dumps up in Steam Pressure Mode and ready to actuate for a Load Reject, PERFORM Step 1 of Attachment 14, Steam Dump Operation for Load Reject Testing

_______ / _______
Initials Date

5.8.8 PERFORM the following during Turbine cooldown as necessary to maintained Turbine Casing ΔT limit < 50°F:

CAUTION: Exhaust hood spray valves should NOT be used as a method of differential temperature control when Turbine speed is less than rated speed (1800 rpm).

A. CYCLE exhaust hood spray valves 1-HS-6556, EXH HOOD SPR VLV and 1-HS-6555, EXH HOOD SPR BYP VLV as necessary to control differential temperature.

_______ / _______
Initials Date

B. PRIOR to initiating turbine trip (reactor trip) OR immediately following turbine trip, ENSURE 1-HS-6556, EXH HOOD SPR VLV and 1-HS-6555, EXH HOOD SPR BYP VLV are closed.

_______ / _______
Initials Date

5.8.9 WHEN Reactor power is below 25%,
THEN
VERIFY the following are OFF:

- ☐ 1-TSLB-6, 1.2, "IR FLUX HI NC-35F"
- ☐ 1-TSLB-6, 2.2, "IR FLUX HI NC-36F"
- ☐ 1-TSLB-6, 1.6, "PR FLUX SETPT LO NC-41P"
- ☐ 1-TSLB-6, 2.6, "PR FLUX SETPT LO NC-42P"
- ☐ 1-TSLB-6, 3.6, "PR FLUX SETPT LO NC-43P"
- ☐ 1-TSLB-6, 4.6, "PR FLUX SETPT LO NC-44P"

_______/_______
Initials Date

CAUTION:
- If plant conditions occur such that a Reactor trip is initiated prior to Step 5.8.16, performance of ODA-108, Post RPS/ESF Actuation Evaluation is required.
- An operator should be available to perform Step 5.8.16 C. at all times in the event a Reactor trip is initiated for optimum steam dump performance.

5.8.10 IF continued turbine cooldown is NOT desired during the performance of Steps 5.8.11 through 5.8.14, PROCEED to Step 5.8.15.

_______/_______
Initials Date

5.8.11 PERFORM the following to lower Turbine load to 60 MW (5%):

A. Using MANUAL Rod Control, MAINTAIN RCS Tave per TDM-301A during Turbine load reduction.

_______/_______
Initials Date

B. MONITOR Steam Dump System operation and Feedwater flow to ensure constant flows during Turbine load reduction.

_______/_______
Initials Date

NOTE: When the cooldown rate at which the monitored temperature starts to slow and continued cooling is no longer needed, then Turbine load reduction may be stopped.

C. On TSE Margin Display in the HP Shaft Section, MONITOR turbine cooldown using Simulated Shaft Temperature during turbine load reduction.

_______/_______
Initials Date

5.8.11 D. In the “Load Control” Section, SET in the desired unloading rate using the Load Rate Setpoint Controller.

_______/_______
Initials Date

> NOTE: The load will immediately begin decreasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.

E. In the “Load Control” Section, LOWER the Load Target Setpoint Controller as necessary to obtain 60 MW or the desired intermediate load to control turbine load.

_______/_______
Initials Date

F. MONITOR Reactor power, RCS T_{AVE}, Steam Dump System operation and Steam Generator level control during turbine load reduction.

_______/_______
Initials Date

5.8.12 WHEN turbine load has decreased below 115 MW (10%), THEN
VERIFY 1-PCIP, 4.6, "TURB $\leq$10% PWR P-13" is ON.

_______/_______
Initials Date

5.8.13 WHEN turbine power has been at 60 MW for approximately 90 minutes OR any other turbine cooldown termination criteria is met, PROCEED to next step.

_______/_______
Initials Date

NOTE:

- Plant Computer point P5446A, FW STM FLOW SETPOINT is the calculated DP setpoint for FW Header and MS Header for 1-SK-509A, FWPT MASTER SPD CTRL.
- Plant Computer point U5002A, FW - MS HEADER DP is the actual DP value for FW Header and MS Header.
- Plant Computer point U5003A, DELTA PROGRAM - ACTUAL DP provides indication of the difference between the programmed differential pressure and actual differential pressure.
- Plant Computer DFS Screen can be used to determine if MFP speed matches Speed Command prior to placing Master Speed Controller in AUTO.

5.8.14 IF 1-SK-509A, FWPT MASTER SPD CTRL is in MANUAL,
THEN
PERFORM the following:

A. IF the running MFP Speed Controller in Manual (1-SK-509B or 1-SK-509C),
THEN
PERFORM the following:

☐ 1) PLACE 1-SK-509A, FWPT MASTER SPD CTRL in AUTO

2) ADJUST Feedwater Pump speed in MANUAL using the running MFP Speed Controller to maintain Programed FW - MS Header D/P.

☐ • 1-SK-509B FWPT A AUTO SPD CTRL

☐ • 1-SK-509C FWPT B AUTO SPD CTRL

3) WHEN FWP DISCH HDR D/P is near the Programed FW - MS Header D/P,
THEN
PLACE the running FWPT (A or B) AUTO SPD CTRL in AUTO:

☐ • 1-SK-509B FWPT A AUTO SPD CTRL

☐ • 1-SK-509C FWPT B AUTO SPD CTRL

☐ 4) GO TO Step 5.8.14 C.

________/________
Initials Date

5.8.14 B. IF the running MFP Speed Controller is in AUTO (1-SK-509B or 1-SK-509C),
THEN
PERFORM the following:

☐ 1) ADJUST Feedwater Pump speed in MANUAL using 1-SK-509A, FWPT MASTER SPD CTRL to maintain Programed FW - MS Header D/P.

☐ 2) WHEN FWP DISCH HDR D/P is near the Programed FW - MS Header D/P,
THEN
PLACE 1-SK-509A, FWPT MASTER SPD CTRL in AUTO.

_______/_______
Initials Date

C. VERIFY the following parameters:

☐ • Program differential pressure is maintained between 1-PI-508, FWP DISCH HDR PRESS and 1-PI-507, MS HDR PRESS. CTRL

☐ • FWP SUCT FLOW AND FWP SUCT PRESS remains within normal bands.

_______/_______
Initials Date

5.8.15 IF desired,
THEN
TRANSFER the 6.9 KV normal buses from 1UT to 1ST per SOP-603A.

_______/_______
Initials Date

5.8.16 WHEN all steps in the section have been initiated or completed, as required,
THEN
PERFORM the following:

A. ENSURE exhaust hood spray valves 1-HS-6556, EXH HOOD SPR VLV and 1-HS-6555, EXH HOOD SPR BYP VLV are CLOSED.

_______/_______
Initials Date

NOTE:
- To ensure optimum steam dump response, Steps 5.8.16 E should be done without delay.
- Step 5.8.16 E should be performed by an operator not associated with EOP-0.0A response.

B. ENSURE 1-PK-507, STM DMP PRESS CTRL in MANUAL. _______/_______
Initials Date

C. ENSURE 1-PK-507, STM DMP PRESS CTRL adjusted to 6.86. _______/_______
Initials Date

NOTE: The loss of Reactive Load (MVAR) on the Main Generator at the time of turbine trip will affect Reactive Load (MVAR) on the opposite Unit.

5.8.16 D. Manually TRIP the reactor.

_______/_______
Initials Date

E. ENSURE 1-PK-507, STM DMP PRESS CTRL in AUTO.

_______/_______
Initials Date

F. PROCEED to EOP-0.0A THEN TRANSITION to IPO-005A
OR
IPO-007A
AND
IPO-009A, when directed.

_______/_______
Initials Date

G. PLACE the following hand switches to CLOSE:

1) 1-HS-2432/5, MSL STRN D\POT VLV

2) 1-HS-2436/9, MSL TO MSR D\POT VLV

_______/_______
Initials Date

NOTE: The following step will initiate Emergency Boration in preps for Cooldown per IPO-005A. The Emergency Boration will be re-verified and completed in IPO-005A.

5.8.16 H. IF desired to initiate Emergency Boration,
THEN
PERFORM the following:

☐ 1) ENSURE a charging pump is running.

CAUTION: If two boric acid transfer pumps are used in the following steps, Unit 2 boric acid transfer pumps are placed in PULL OUT and auto makeup to the VCT is turned off. This is because two pumps shall not be run on one boric acid storage tank. If blended flow or boration becomes necessary for Unit 2, then one of the Unit 1 pumps is stopped to make the like pump available on Unit 2.

NOTE: 5.8.16 H2) may be performed at any time with the Unit 2 Unit Supervisor concurrence.

2) IF desired to run two boric acid transfer pumps for the boration,
THEN
NOTIFY **Unit 2** to perform the following:

☐ a. PLACE 43/2-MU, RCS MU MODE SELECT in OFF

b. PLACE the boric acid transfer pumps in PULL OUT.

☐ • 1/2-APBA1, BA XFER PMP 1

☐ • 1/2-APBA2, BA XFER PMP 2

NOTE:
- Normally boration should start with BAT X-01. When BAT X-01 is approximately 60%, boration should be shifted to BAT X-02. If using two boric acid transfer pumps, both tanks will be in use.
- If Boric Acid flow reduces, the Boric Acid filter may be clogging.
- The normal sample point for RCS boron is the CVCS Mixed Bed Demin inlet sample point. Until the CVCS Demins are saturated, this sample will not be indicative of actual RCS boron concentration.

3) START the desired boric acid transfer pump(s).

☐ • 1/1-APBA1, BA XFER PMP 1

☐ • 1/1-APBA2, BA XFER PMP 2

5.8.16.H

☐ 4) OPEN 1/1-8104, EMER BORATE VLV AND RECORD flow & time.

Time______ 1-FI-183A, EMER BORATE FLO_____ gpm

☐ 5) CYCLE 1/1-LCV-112A, VCT LVL CTRL OR PLACE in AUTO as necessary to maintain desired VCT level.

_______/_______
Initials Date

I. VERIFY EITHER of the following:

☐ RCS Boration rate greater than 30 GPM
OR
☐ Shutdown margin shows at least 30 ppm excess boron. _______/_______
Initials Date

J. IF Demins have been previously prepared by SOP-103A,
THEN
ENSURE 1/1-TCV-0129 is in the DEMIN position. _______/_______
Initials Date

K. 1) IF RCS boration is secured prior to CVCS Mixed Bed outlet boron being verified greater than the NDR required value,
THEN
BYPASS the demins by PLACING 1/1-TCV-0129, LTDN DIVERT VLV, in the VCT position. _______/_______
Initials Date

2) WHEN RCS boration is resumed,
THEN
PLACE 1/1-TCV-0129, LTDN DIVERT VLV, in the DEMIN position. _______/_______
Initials Date

L. FILE this procedure per ODA-104. _______/_______
Initials Date

COMMENTS:____

____

____

IPO-003A Satisfactorily Completed____________________________/____________________
Shift Manager Date

6.0 REFERENCE

6.1 Performance References

Technical Specifications/TRM/ODCM

- TS 3.1.3, Moderator Temperature Coefficient (MTC)
- TS 3.1.6, Control Bank Insertion Limits
- TS 3.2.3, Axial Flux Difference (AFD)
- TS 3.3.1, Reactor Trip System (RTS) Instrumentation
- TS 3.4.1, RCS Pressure, Temperature, and Flow Departure From Nucleate Boiling (DNB) Limits
- TS 3.4.16, RCS Specific Activity
- TS 3.7.3, Feedwater Isolation Valves (FIVs) and Feedwater Control Valves (FCVs) and Associated Bypass Valves
- TS 3.7.5, Auxiliary Feedwater (AFW) System
- TRM 13.2.32, Axial Flux Difference
- TRM 13.3.33, Turbine Overspeed Protection
- TRM 13.7.38, Main Feedwater Isolation Valve Pressure/Temperature Limit
- ODCM 3/4.11.2, Gaseous Effluents

6.1 CPNPP Procedures

- ABN-302, Feedwater, Condensate, Heater Drain System Malfunction
- ABN-305, Auxiliary Feedwater System Malfunctions
- CHM-120, Primary Chemistry
- CHM-130, Secondary Chemistry
- CLI-741, Setpoint Modification and DRMS Pre-Release Surveillance
- COP-101A, Reactor Coolant System
- ETP-908, Sound Powered Phones and Evacuation Alarm System Periodic Testing
- INC-4909, Channel Calibration ATWS Mitigation System Actuation Circuitry (AMSAC)
- INC-7018A, Reactor Coolant System Flow Measurement
- INC-7376A, Channel Calibration Neutron Flux Power Range Channels
- INC-7379A, Analog Channel Operational Test and Channel Calibration Neutron Flux Intermediate Range Channel N35
- INC-7380A, Analog Channel Operational Test and Channel Calibration Neutron Flux Intermediate Range Channel N36
- INC-7387A, Channel Calibration Neutron Flux Intermediate Range High Voltage and Detector Plateau, Channel N35
- INC-7388A, Channel Calibration Neutron Flux Intermediate Range High Voltage and Detector Plateau, Channel N36
- INC-7389A, Channel Calibration Neutron Flux Power Range High Voltage and Detector Plateau
- INC-7393A, Channel Calibration Neutron Flux Power Range Channel Ion Current Gain and Summing Level Amplifier
- IPO-002A, Plant Startup from Hot Standby
- MSM-CO-6860, Borg-Warner Pneumatic Hydraulic Actuator Maintenance
- NUC-114, Core Performance Engineering Periodic Duties
- NUC-116, Rod Withdrawal Limits
- NUC-204, Target Axial Flux Difference

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6.1 CPNPP Procedures (Continued)

- NUC-101, Zero Power and Power Ascension Tests Sequence
- NUC-118, Xenon Oscillation Dampening
- ODA-104, Operations Department Document Control
- ODA-308, LCO Tracking Program
- OPT-102A, Operations Shiftly Routine Tests
- OPT-104A, Operations Weekly Routine Tests
- OPT-206A, AFW System
- OPT-217A, Turbine Overspeed Protection System Test
- OPT-302, Calculating Power Tilt Ratio
- OPT-309, Unit Calorimetric
- OPT-410A, Pre-startup Turbine Trip Checks
- OWI-104-17, U1 Turbine
- OWI-104-55, Power Change Log
- OWI-107, Operations Department Turnover and Briefing Instructions
- OWI-409, Equipment Rotation
- RWS-201, Gaseous Waste Processing System
- SOP-102A, Residual Heat Removal System
- SOP-103A, Chemical and Volume Control System
- SOP-104A, Reactor Makeup and Chemical Control System
- SOP-106A, Boron Thermal Regeneration System
- SOP-301A, Main Steam System
- SOP-302A, Feedwater System
- SOP-303A, Condensate System
- SOP-308A, Heater Drains System

6.1 CPNPP Procedures (Continued)

- SOP-311, Auxiliary Steam System
- SOP-401A, Turbine Control Fluid System
- SOP-404A, Turbine Lube Oil System
- SOP-405A, Main Generator System
- SOP-406A, Generator Hydrogen System
- SOP-407A, Generator Seal Oil System
- SOP-408A, Generator Primary Water System
- SOP-506, Spent Fuel Pool Cooling and Cleanup System
- SOP-601A, Unit 1 Main and Auxiliary Transformers
- SOP-603A, 6900 V Switchgear
- SOP-611A, Isolated Phase Bus Duct Cooling System
- SOP-906, Plant Process Computer System Guidelines
- STA-125, Luminant Corporate Compliance Procedure Control
- STA-421, Initiation of Condition Reports
- STA-501, Nonroutine Reporting
- STA-603, Control of Station Radioactive Effluents
- STA-609, Reactor Coolant Water Chemistry Control Program
- STA-610, Secondary Water Chemistry Control Program
- STA-617, High Voltage Switching and Clearance
- STA-732, Primary-to-Secondary Leakage
- STA-735, Nuclear Fuel Integrity Program
- TDM-101A, Reactor Core & Power Data
- TDM-102A, Reactor Control Rod Data
- TDM-310A, Circulating Water System Data
- TDM-401A, Turbine/Generator Limit Curves
- TDM-501A, SG-Feedwater Controller Data

6.2 Development References

- Core Operating Limit Report (COLR)
- Nuclear Design Report (NDR)
- Westinghouse document 83TB-6-056
- Limiting Conditions for Westinghouse Fuel Operation TIM-81353
- Technical Evaluation SE-90-1380, AFW Pressure
- Technical Evaluation SE-90-1398, FWIV
- Technical Evaluation SE-90-1401, FW Penetrations
- Technical Evaluation SE-91-0387, Nuclear Fuel
- CPSES Letter 9014252, Main Feedwater Isolation Valves
- CPSES Letter 9022196, Auxiliary Feedwater System Temperature
- WPT-14869, ET-NSL-OPL-II-92-488, Boration Technical Specifications
- SER 24-91, Inadequate Control of Reactivity Changes During a Plant Shutdown Results in an Unplanned Plant Transient
- SOER 94-01, Nonconservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections, and Water-Solid Conditions
- SOER 03-2, “Managing Core Design Changes”, July 2003
- SEN 156, Recurring Event, Unrecognized Reactivity Mismanagement While Performing a Reactor Shutdown
- SER 15-96, Inappropriate Operator Actions During Low-Power Operations
- DM 98-004, Supplemental Cooling for Unit 1 HP Turbine Transmitter Rack (1-SA11Z031)
- CPES-I-1115, Turbine-Generator Digital Controls Specification
- NRC Inspection Manual, Inspection Procedure 61706, Core Thermal Power Evaluation
- WCAP-16840-P, Comanche Peak Nuclear Power Plant Stretch Power Uprate Licensing Report

6.2 Development References (Continued)

- Commitment 3667655, Reactivity Management-Standards & expectations(SOER 07-01 REC 1)
- Commitment 3667657, Reactivity Management-Supervision (SOER 07-01 REC 2)
- Commitment 26982, Nonconservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections, and Water-Solid Conditions (SOER 94-1 REC 2)
- Commitment 4356433, CAPR for turbine generator failure
- Commitment 27393, Address Limitations in Core Performance Tools (SOER 03-2), Rec 4
- Commitment 4872850, Revise Mode Change Checklists
- Commitment 3691286, Conduct Operator or Maintenance Rounds on Major Station Transformers

7.0 ATTACHMENTS

- Attachment 1, Checklist Signoff Required Prior to Entry Into MODE 1
- Attachment 2, Delta I Control/Dampening Xenon Oscillations
- Attachment 3, Power Change Worksheet
- Attachment 4, Turbine Overspeed Test
- Attachment 5, Preplanned Outage Activities
- Attachment 5A, Preplanned Equipment Alignment Activities
- Attachment 6, OPT-217 Power Reduction
- Attachment 6A, Down Power to approximately 700 MWE
- Attachment 6B, MSR Excess Heating Steam Valve Restoration
- Attachment 7, Establishing Separator Drain Tank Normal Drain Flow
- Attachment 8, Planned Trip Data Collection
- Attachment 9, Planned Trip Operations Briefing
- Attachment 10, Stator Bar Monitoring Data
- Attachment 11, Shutdown To MODE 3 From MODE 2
- Attachment 12, Instructions for Single Condensate Pump Operation
- Attachment 13, Steps to Ready the Unit for Turbine Load Increase Following Power Reduction per Section 5.6
- Attachment 14, Steam Dump Operation for Load Reject Testing
- Attachment 15, Steam Trap Blowdown
- Attachment 16, Extended Operation with Turbine at 1800 RPM for Testing
- Attachment 17, MODE 1 Bubble Chart
- Attachment 18, Pressurizer Spray Valve Bypass Adjustment
- Attachment 19, Pre-staging AME Pump |

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ATTACHMENT 1
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CHECKLIST SIGNOFF REQUIRED PRIOR TO ENTRY INTO MODE 1

When the MODE 1 surveillances were completed and signed as REVIEW VALID THRU MODE 1 per IPO-002A, the Shift Manager may N/A the signoffs required by this attachment. Note that the Review and signoffs were completed by IPO-002A in the Comments Section.

Review the following, checking for conditions which may affect operation in MODE 2 or MODE 1.

	INITIALS	REVIEW VALID THROUGH DATE		
			1.0	All required surveillances for MODE 1 have been performed within their respective cycles and have met their respective criteria. Any procedure changes for MODE 1 entry required due to amendments to Technical Specifications, Design Modifications or commitments to regulatory agencies have been implemented. Any other department specific items (e.g., work, testing, corrective action, configuration control item) which would prevent entry into MODE 1 have been completed. The following items are to be signed by a designee in each department.
*	______	__________		• System Engineering (ZS)
*	______	__________		• Chemistry (PCHM)
*	______	__________		• Radiation Protection (PRP)
*	______	__________		• Fire Protection (PFP)
*	______	__________		• Core Performance (ZRC)
*	______	__________		• Operations (POS)
*	______	__________		• Engineering Technical Support (ZT)
*	______	__________		• Operations Support (POSP)
*	______	__________		• Work Control Online Scheduling (ISCO)/Scheduling Support (IIPM) includes Maintenance (PM)
*	______	__________		• Outage Management (IWCM)
*	______	__________		• Design Mod Team (SZ)
*	______	__________		• External Affairs (LCPC)
*	______	__________		• Plant Reliability (ZST)

ATTACHMENT 1
PAGE 2 OF 3

CHECKLIST SIGNOFF REQUIRED PRIOR TO ENTRY INTO MODE 1

INITIALS / DATE

*______/____2. Ensure all OPT-102A surveillances have been performed within the previous 12 hours before MODE 1 entry, as follows:

a. Perform all OPT-102A MODE 1 surveillances listed under the MID shift heading, except for OPT-309.

b. Perform all OPT-102A daily (once per 24 hr.) surveillances listed under the DAY shift headings, except for OPT-309.

c. N/A the remaining DAY shiftly (once per 12 hr.) surveillances since they were completed under the MID shift heading.

d. Enter MODE change into the Comments section and complete OPT-102A reviews.

______/_____ 3. OPT-104A has been performed within the last 7 days for MODE 1.

______/_____ 4. ODA-308 has been reviewed for any LCOARs that may affect entry into MODE 1. If any LCOAR affects entry into Mode 1, that LCOAR must be evaluated for TS 3.0.4 criteria per ODA-308.

______/_____ 5. The temporary modification log has been reviewed for any that may affect entry into MODE 1. Any temporary modifications which will remain open following the MODE change shall have the 50.59 screenings and evaluations reviewed to ensure they remain valid for MODE 1 entry.

______/_____ 6. The clearance report index has been reviewed for any that may affect entry into MODE 1.

______/_____ 7. The Annunciator/Instrument Out-of-Service log has been reviewed for any that may affect entry into MODE 1.

______/_____ 8. The locked component deviation log has been reviewed for any that may affect entry into MODE 1.

______/_____ 9. Standing orders have been reviewed for any that may affect entry into MODE 1.

______/_____10. Shift orders have been reviewed for any that may affect entry into MODE 1.

______/_____11. The system status file deviations have been reviewed for any that affect entry into MODE 1.

ATTACHMENT 1
PAGE 3 OF 3

CHECKLIST SIGNOFF REQUIRED PRIOR TO ENTRY INTO MODE 1

INITIALS / DATE

______/_____ 12. Review all CRs identified as MODE 1 restraints.

______/_____ 13. Plant Computer points that have been removed from alarm limit checking have been reviewed for affect on MODE 1 operation.

______/_____ 14. All surveillance requirements for the Mode to be entered have been verified to be met utilizing the Surveillance Mode Change Report provided by the Scheduling Coordinators for each specific Mode change. This report SHALL be vaulted with the completed IPO.

______/_____ 15. All post work testing required has been accomplished as listed on the Work Orders With Post Work Test Steps Report.

______/_____ 16. The Director, Operations has reviewed open SORC action items which may affect entry into MODE 1.

*______/_____ 17. The Director, Operations or Shift Operations Manager has granted permission to change MODE.

______/_____ 18. Engineering ENSURE NRC Inspection Manual Chapter 0326 issues have been properly evaluated, including issues identified during the current outage, prior to exiting the outage.

* IF shutdown has been $\leq$24 hours, THEN these are the only items required to be signed off prior to entry into MODE 1.

COMMENTS: ____

____

____

____

____

Approved by: ____/______________
SHIFT MANAGER DATE

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ATTACHMENT 2
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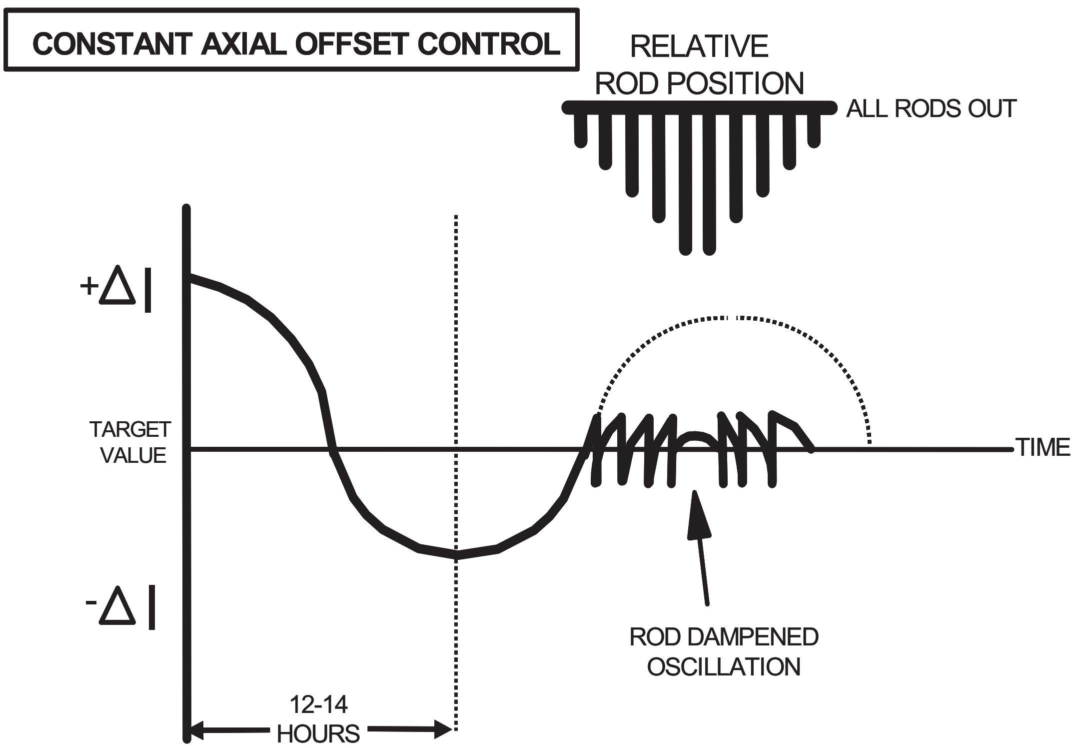
DELTA I CONTROL/DAMPENING XENON OSCILLATIONS

If a ΔI swing is greater than ±1.5%, or uncontrollable due to size or unavailability of rods, or the operator has any questions about controlling the ΔI swing, contact Core Performance Engineering for guidance in controlling ΔI. This attachment should be used as a general guideline during slow, controlled power changes.
Xenon oscillations should be dampened out. The method discussed in this attachment is only applicable to ΔI swings less than 1.5%. Xe swings are controlled by continually forcing ΔI to the



target value. This method will usually dampen small Xe swings in approximately 12 hours or through one peak.

ΔI can be maintained using a combination of the following:

- With ΔI more negative than the target, initiate boration and use rod withdrawal to bring ΔI to the target and then maintain the target value.

- With ΔI more positive than the target, initiate dilution and use rod insertion to bring ΔI to the target and then maintain the target value.

IF THERE ARE ANY QUESTIONS OR THE ΔI SWING is >1.5%, CONTACT CORE PERFORMANCE ENGINEERING FOR GUIDANCE.

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POWER CHANGE WORKSHEET

Power Change Reactivity Calculation

Unit ____ Cycle ____ Date __________ Time ______ Page 1 of 3

A. Obtain Current Plant Conditions

A.1 RCS Boron __________ ppm
A.2 Power Level __________ % RTP
A.3 CBD Position __________ steps
A.4 Core Burnup __________ MWD/MTU
A.5 Burnup Range ___BOL ___MOL ___EOL
[Reference NDR Section 5.1 for Burnup Range]

Note: Core Burnup should be obtained from CHORE. If CHORE is not available, estimate Core Burnup using the following formula.

Burnup Estimate = [Number of Days the Cycle has Operated] x 44

B. Estimate Target CBD Position

B.1 Target Power Level (or Target MWe / HFP MWe x 100%) __________ % RTP

IF planning a Power DECREASE (B.1 < A.2), **THEN** B.2 =

$$\underset{\text{Current CBD Position [A.3]}}{\underline{\qquad}} + \left[\underset{\text{Target Power Level [B.1]}}{\underline{\qquad}} - \underset{\text{Current Power Level [A.2]}}{\underline{\qquad}}\right] \times \left[\underset{\text{Core Burnup [A.4]}}{\underline{\qquad}} + 8{,}000\right] / 12{,}000$$

IF planning a Power INCREASE (B.1 $\geq$ A.2), **THEN** B.2 =

$$\underset{\text{Current CBD Position [A.3]}}{\underline{\qquad}} + \left[\frac{\left(215 - \underset{\text{Current CBD Position [A.3]}}{\underline{\qquad}}\right) \times \left(\underset{\text{Target Power Level [B.1]}}{\underline{\qquad}} - \underset{\text{Current Power Level [A.2]}}{\underline{\qquad}}\right)}{\left(100 - \underset{\text{Current Power Level [A.2]}}{\underline{\qquad}}\right)}\right]$$

B.2 Target CBD Position = __________ steps

C. Power Defect Reactivity Change

Determine change in Reactivity due to Power Defect, based on current RCS Boron, using:

NDR Table 5.1 for BOL   *NDR Table 5.2 for MOL*   *NDR Table 5.3 for EOL*

C.1 Absolute Value of Power Defect at Current Power Level [A.2] = __________ pcm
C.2 Absolute Value of Power Defect at Target Power Level [B.1] = __________ pcm
C.3 Δ Power Defect = [C.1] - [C.2] = __________ pcm

NOTE: [C.1] and [C.2] should always be positive (+) values. [C.3], Δ Power Defect, will be positive (+) for a power DECREASE, negative (-) for a power INCREASE.

If desired, use pages 4-6 of Att 3 as a guide for NDR Table Interpolation.

ATTACHMENT 3
PAGE 2 OF 6

POWER CHANGE WORKSHEET

Power Change Reactivity Calculation

Unit ____ Cycle ____ Date __________ Time ______ Page 2 of 3

D. Control Rod Motion Reactivity Change

Determine change in Reactivity due to Control Rod Motion, using:

NDR Figure 5.16 for BOL	*NDR Figure 5.17 for MOL*	*NDR Figure 5.18 for EOL*

D.1 Absolute Value of CBD Integral Worth at Current CBD Position [A.3] = __________ pcm

D.2 Absolute Value of CBD Integral Worth at Target CBD Position [B.2] = __________ pcm

D.3 Δ Control Rod Worth = [D.1] - [D.2] = __________ pcm

NOTE: [D.1] and [D.2] should always be positive (+) values. [D.3], Δ CR worth, will be negative (-) for Rod INSERTION, and positive (+) for a Rod WITHDRAWAL.

E. Determine Reactivity Worth Required from Boron Adjustment

E.1 Δ Boron Worth = [__________ + __________] x [-1] = __________ pcm
(Δ CR Worth [D.3]) (Δ Power Defect [C.3])

NOTE: [E.1], Δ Boron Worth, will be negative (-) when BORATION is needed, and positive (+) when DILUTION is needed.

F. Determine Integral Boron Worth at Current Conditions

For this section, utilize the following NDR tables.

NDR Table 5.10 for BOL	*NDR Table 5.11 for MOL*	*NDR Table 5.12 for EOL*

Utilize a CORE AVERAGE TEMPERATURE value of 557 degrees F to determine the worth.

F.1 Integral Boron Worth at __________ ppm = __________ pcm
(Current RCS Boron [A.1])

NOTE: [F.1] will always be a negative (-) reactivity value.

If desired, use pages 4-6 of Att 3 as a guide for NDR Table Interpolation.

G. Determine Target RCS Boron Value

G.1 Target Integral Boron Worth = [__________ + __________] = __________ pcm
([F.1]) ([E.1])

G.2 Target RCS Boron value (using Tables from F above, at 557 deg F) = __________ ppm

NOTE: If desired, use pages 4-6 of Att 3 as a guide for NDR Table Interpolation.

H. Determine RCS Boration / Dilution Volume

Determine appropriate Boration OR Dilution volume using CHORE or TDM-201A/B, to change RCS Boron from [A.1] to [G.2]

H.1 Check appropriate method for RCS Boron change:
☐ Boration Volume
☐ Dilution Volume

H.2 Volume Required: = __________ gallons

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POWER CHANGE WORKSHEET

Power Change Reactivity Calculation

Unit ____ Cycle ____ Date __________ Time ______ Page 3 of 3

NOTE: This calculation does **NOT** include any adjustments for changes in Xenon worth from the equilibrium value at a power level of [A.1].

If Power is being **DECREASED** from steady state, Xenon will initially build in due to the decrease in flux, adding negative reactivity. Therefore boration should be reduced for a slower power change.

If Power is being **INCREASED** from steady state, the higher flux will result in an initial reduction in Xenon, adding positive reactivity. Therefore the dilution volume should be reduced from the estimate for a slower power change.

If possible, discuss Xenon impacts, AFD control strategies, and schedule with Core Performance Engineering prior to the power change.

I. Summary of Results

To change power immediately from ____________ (Current Power Level [A.2]) to ____________ (Target Power Level [B.1]), it is estimated that

__________ (Volume [H.2]) gallons of __________ (Bor or Dil [H.1]) will be required, and CBD final position will

be approximately __________ (Target CBD Position [B.2]) steps.

Comments: ____

____

____

____

____

____

____

Performed By (RO): ______________________ Date: __________

Reactor Operator Review: ______________________ Date: __________

Unit Supervisor: ______________________ Date: __________

ATTACHMENT 3
PAGE 4 OF 6

POWER CHANGE WORKSHEET

Interpolation Guide for Power Change NDR Reactivity Calculation

This attachment provides guidance for interpolation of values on Attachement 3 Pages 1-3, using the NDR Tables as referenced in the applicable step.

Value [C.1] - Power Defect at Current Conditions

X = Current Boron (ppm) [value A.1]	X = ________	ppm
Y = Current Power Level (% RTP) [value A.2]	Y = ________	% RTP
X_1 = First Boron on NDR Table LESS than or equal to X	X_1 = ________	ppm
X_2 = First Boron on NDR Table HIGHER than X	X_2 = ________	ppm
Y_1 = First Power on NDR Table LESS than or equal to Y	Y_1 = ________	% RTP
Y_2 = First Power on NDR Table HIGHER than Y	Y_2 = ________	% RTP

Step 1

$$(\underset{\text{Power Defect }(X_1, Y_1)}{\underline{\qquad\qquad}}) + ([\underset{X}{\underline{\qquad}} - \underset{X_1}{\underline{\qquad}}] / [\underset{X_2}{\underline{\qquad}} - \underset{X_1}{\underline{\qquad}}] \times [\underset{\text{Power Defect }(X_2, Y_1)}{\underline{\qquad}} - \underset{\text{Power Defect }(X_1, Y_1)}{\underline{\qquad}}])$$

$$= \underset{\text{Power Defect }(X, Y_1)}{\underline{\qquad\qquad}}$$

Step 2

$$(\underset{\text{Power Defect }(X_1, Y_2)}{\underline{\qquad\qquad}}) + ([\underset{X}{\underline{\qquad}} - \underset{X_1}{\underline{\qquad}}] / [\underset{X_2}{\underline{\qquad}} - \underset{X_1}{\underline{\qquad}}] \times [\underset{\text{Power Defect }(X_2, Y_2)}{\underline{\qquad}} - \underset{\text{Power Defect }(X_1, Y_2)}{\underline{\qquad}}])$$

$$= \underset{\text{Power Defect }(X, Y_2)}{\underline{\qquad\qquad}}$$

Step 3

$$(\underset{\text{Power Defect }(X, Y_1)}{\underline{\qquad\qquad}}) + ([\underset{Y}{\underline{\qquad}} - \underset{Y_1}{\underline{\qquad}}] / [\underset{Y_2}{\underline{\qquad}} - \underset{Y_1}{\underline{\qquad}}] \times [\underset{\text{Power Defect }(X, Y_2)}{\underline{\qquad}} - \underset{\text{Power Defect }(X, Y_1)}{\underline{\qquad}}])$$

$$[C.1] = \underset{\text{Power Defect }(X, Y)}{\underline{\qquad\qquad}}$$

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POWER CHANGE WORKSHEET

Value [C.2] - Power Defect at Target Conditions

X = Current Boron (ppm) [value A.1]	X = ________ ppm
Y = Target Power Level (% RTP)	Y = ________ % RTP
X_1 = First Boron on NDR Table LESS than or equal to X	X_1 = ________ ppm
X_2 = First Boron on NDR Table HIGHER than X	X_2 = ________ ppm
Y_1 = First Power on NDR Table LESS than or equal to Y	Y_1 = ________ % RTP
Y_2 = First Power on NDR Table HIGHER than Y	Y_2 = ________ % RTP

Step 1

(________) +
Power Defect (X_1, Y_1)

([________ - ________] / [________ - ________] x [________ - ________])
X, X_1, X_2, X_1, Power Defect (X_2, Y_1), Power Defect (X_1, Y_1)

= ________
Power Defect (X, Y_1)

Step 2

(________) +
Power Defect (X_1, Y_2)

([________ - ________] / [________ - ________] x [________ - ________])
X, X_1, X_2, X_1, Power Defect (X_2, Y_2), Power Defect (X_1, Y_2)

= ________
Power Defect (X, Y_2)

Step 3

(________) +
Power Defect (X, Y_1)

([________ - ________] / [________ - ________] x [________ - ________])
Y, Y_1, Y_2, Y_1, Power Defect (X, Y_2), Power Defect (X, Y_1)

[C.2] = ________
Power Defect (X, Y)

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Value [F.1]

X = Current Boron (ppm) [value A.1] X = ____________ ppm
X_1 = First Boron on NDR Table LESS than or equal to X X_1 = ____________ ppm
X_2 = First Boron on NDR Table HIGHER than X X_2 = ____________ ppm

Integral Boron Worth (X, 557) = ____________
Int Boron Worth (X_1, 557)

+ ([________ - ________] / [________ - ________] x [________ - ________])
X, X_1, X_2, X_1, Int Boron Worth (X_2, 557), Int Boron Worth (X_1, 557)

[F.1] = ____________
Int Boron Worth (X, 557)

Value [G.2]

Y = Target Int Boron Worth [Value G.1] Y = ____________ pcm
Y_1 = First Int Boron Worth at 557 degrees on NDR Table which is MORE POSITIVE than, or equal to, Y Y_1 = ____________ pcm
Y_2 = First Int Boron Worth at 557 degrees on NDR Table which is MORE NEGATIVE than Y Y_2 = ____________ pcm
X_1 = Boron on NDR Table which corresponds to Y_1 X_1 = ____________ ppm
X_2 = Boron on NDR Table which corresponds to Y_2 X_2 = ____________ ppm

Target RCS Boron = ____________
X_1

+ ([________ - ________] / [________ - ________] x [________ - ________])
Y, Y_1, Y_2, Y_1, X_2, X_1

[G.2] = ____________
Target RCS Boron

COMMENTS:____

____

ATTACHMENT 4
PAGE 1 OF 10

[C] TURBINE OVERSPEED TEST

CAUTION: The turbine should be tripped if any of the following limits are exceeded:

- Turbine bearing vibration $\geq$7 mils (Turbine Display)
- Generator bearing vibration $\geq$8 mils (Generator Display)
- Shaft vibration $\geq$14 mils (Turbine Display and Generator Display)

NOTE: This test is considered an INFREQUENT EVOLUTION.

1. ENSURE a Turbine Vendor Representative is available for consultation during performance of this test.

   ________/________
   Initials Date

NOTE: 1-ALB-10A, 2.11, GEN CORE MONITOR ALARM may be on during Main Turbine speed increase to 1800 RPM and should clear after the Generator Core Monitor is placed in service by the subsequent steps.

2. VERIFY the Relative Expansions and Casing Differential Temperature are less than allowable limits by verifying Turbine Display.

   ________/________
   Initials Date

NOTE: The TSE Margin Display has 2 Bar Graphs. Each of the 2 Bar Graphs has a positive and a negative temperature scale which represent Upper and Lower TSE Margins. At this point the upper bar graphs should be green and above 60°F.

3. VERIFY upper TSE Margin is above 60°F and Upper Admission Bar is green on the “TSE Margin” Display.

   ________/________
   Initials Date

ATTACHMENT 4
PAGE 2 OF 10

[C] TURBINE OVERSPEED TEST

CAUTION: If the Upper TSE Margin stops the Main Turbine rollup prior to attaining at least 1765 RPM, Main Turbine speed should immediately be reduced to approximately 500 RPM to allow the Main Turbine to continue soaking.

NOTE:
- Hold Setpoint Function on the “TG Control” Display may be used at anytime during the Turbine Roll-up if problems occur.
- Initiating the Hold Setpoint Function with Turbine Speed below 1700 RPM will automatically reduce (ramp down) the turbine speed to 500 rpm. The turbine then remains at warm-up speed until the Operator resumes startup.

4. In the “Speed Control” Section, ROLL the Main Turbine to 1800 RPM by raising the “Speed Target” to 1800 RPM.

   ______/______
   Initials Date

5. VERIFY 1-ALB-9B Window 3.9, "EHC Fluid Temp Hi" DARK.

   ______/______
   Initials Date

6. VERIFY Lube Oil Temperature is maintained at approximately 113°F as indicated on the TURB BRG TEMP RCDR 1 recorder (1-SB10T010.G01 recorder point 12 on 1-CB-10) while Main Turbine speed is increased.

   ______/______
   Initials Date

7. VERIFY 1-HS-6579, TURB SHAFT LIFT OIL PMP automatically stops at a Main Turbine speed of approximately 540 RPM.

   ______/______
   Initials Date

8. WHEN turbine speed is approximately 1400 rpm,
   THEN
   PLACE the EXCITER AIR DRIER and EXCITER HEATER in OFF at the Unit 1 GENERATOR AUXILIARIES CABINET JC91.

   ______/______
   Initials Date

NOTE: Past OE indicates that low lube oil pump discharge pressure may be caused by a stuck open check valve on one of the operating auxiliary lube oil pumps. Stopping the auxiliary oil pumps in this condition may cause a turbine trip. (CR-2015-011038)

9. VERIFY 1-PI-6558, TURB L/O PMP DISCH PRESS is between 155 and 175 psig.

   ______/______
   Initials Date

ATTACHMENT 4
PAGE 3 OF 10

[C] TURBINE OVERSPEED TEST

10. WHEN Main Turbine speed increases above 1765 RPM,
THEN
STOP all running Auxiliary Oil Pumps AND PLACE in AUTO:

☐ • 1-HS-3287, TURB AUX L/O PMP A

☐ • 1-HS-3288, TURB AUX L/O PMP B

☐ • 1-HS-3289, TURB AUX L/O PMP C

_______/_______
Initials Date

11. VERIFY no unexpected or sudden increase in vibration is indicated:

☐ • Turbine Display

☐ • Generator Display

☐ • Alarm Summary Display (Asd)

_______/_______
Initials Date

> NOTE:
> - OPT-217A shall be performed within 24 hours after reaching 1800 RPM if it has not been performed within it's surveillance frequency (RT# 500472).
> - The turbine should be allowed to soak at rated speed until temperatures and expansions have stabilized. The Turbine Vendor representative may determine when this requirement is satisfied.

12. VERIFY actual turbine speed is at approx. 1800 RPM and stable.

_______/_______
Initials Date

ATTACHMENT 4
PAGE 4 OF 10

[C] TURBINE OVERSPEED TEST

13. PERFORM the following to lower overspeed trip setpoints on two E1553 Braun Speed Modules located at **EA043** and **EA083** (numbers are on rail at rear of rack behind top of modules) in the Protection System Cabinet 1-JC41 (The Braun modules will also be monitored for the overspeed):

1st 2nd

☐ ☐ a. PRESS E and P keys simultaneously (starts programming phase; display P00.00, first set of zeroes flashing).
☐ ☐ b. SET group number (first set of zeroes) to 02 using ⇑ key or ⇓ key, as necessary.
☐ ☐ c. TOGGLE to step (2nd two numbers) with ⇐ key.
☐ ☐ d. ENSURE step number remains at "00".
☐ ☐ e. OPERATE E key to call parameter (ensure setpoint displayed).
☐ ☐ f. SET overspeed to 01840 using⇐ key for number entry point (flashes) and ⇑ key or ⇓ key to change values.
☐ ☐ g. SAVE setpoint with E key.
☐ ☐ h. USE P key to return to operation.
☐ ☐ I. VERIFY setpoint with ⇑ key
☐ ☐ j. If the High/Low speed capture mode is required, PERFORM the following:
PRESS keys P and ⇐ simultaneously.
- Activated mode is shown by flashing of LED4
- From this moment the max/min-values are stored.

☐ k. REPEAT steps for second module.

Overspeed setpoint reduced ________ / ________
Initials Date

14. On "TG Control" Display in the "Speed Control" Section, RAISE the "Speed Target" to approximately 1850 RPM AND verify the turbine trips at approx. 1840 RPM.

________ / ________
Initials Date

NOTE:	While the turbine is rolling up OBSERVE the highest actual turbine speed obtained on the overspeed trip.

15. On the Braun Speed Modules OBSERVE AND RECORD the following data AND VERIFY the turbine tripped between 1830 - 1845 RPM.

- Overspeed trip speed ___________ RPM ________ / ________
Initials Date

ATTACHMENT 4
PAGE 5 OF 10

[C] TURBINE OVERSPEED TEST

[CV]
16. PERFORM the following to reset overspeed trip setpoints lowered on the TWO of the Braun Speed Modules **EA043** and **EA083** selected in Step 13:

1st 2nd

☐ ☐ a. If the High/Low speed capture mode was used, PERFORM the following:
1. PRESS key ⇑ To display and record the maximum measured speed value.
2. PRESS key ⇓ To display and record the minimum measured speed value.
3. Exit mode by PRESSING P and Ü again simultaneously (LED4 does not blink)

☐ ☐ b. PRESS E and P keys simultaneously (starts programming phase; display P00.00, first set of zeroes flashing).

☐ ☐ c. SET group number (first set of zeroes) to 02 using ⇑ key or ⇓ key, as necessary.

☐ ☐ d. TOGGLE to step (2nd two numbers) with ⇐ key.

☐ ☐ e. ENSURE step number remains at “00”.

☐ ☐ f. OPERATE E key to call parameter (ensure setpoint displayed).

☐ ☐ g. SET overspeed to 01980 using ⇐ key for number entry point (flashes) and ⇑ key or ⇓ key to change values.

☐ ☐ h. SAVE setpoint with E key.

☐ ☐ I. USE P key to return to operation.

☐ ☐ j. VERIFY setpoint with ⇑ key

☐ k. REPEAT steps for second module.

Overspeed setpoint reset

Performed: ________/________
Initials Date

Verified: ________/________
Initials Date

17. RESET the Hardware O/S Trip by performing the following:

☐ a. In the Overspeed Protection Cabinet, momentarily TOGGLE switch S31.

☐ b. VERIFY that the module lights illuminate AND that the O/S Trip condition clears.

________/________
Initials Date

18. On the TG Control Display, VERIFY Turbine Trip Bar RED.

________/________
Initials Date

ATTACHMENT 4
PAGE 6 OF 10

[C] TURBINE OVERSPEED TEST

19. VERIFY the following valves indicate CLOSED:

- ☐ • 1-ZL-2429A, HPT STOP VLV 1
- ☐ • 1-ZL-2431A, HPT STOP VLV 2
- ☐ • 1-ZL-2430A, HPT STOP VLV 3
- ☐ • 1-ZL-2428A, HPT STOP VLV 4
- ☐ • 1-ZL-2414A, MSR B TO LPT 1 LP STOP VLV 1
- ☐ • 1-ZL-2413A, MSR A TO LPT 1 LP STOP VLV 2
- ☐ • 1-ZL-2415A, MSR B TO LPT 2 LP STOP VLV 1
- ☐ • 1-ZL-2416A, MSR A TO LPT 2 LP STOP VLV 2

_______ / _______
Initials Date

20. IF turbine is to be relatched,
THEN
PERFORM the following to ensure the Turbine is reset:

A. On the TG Control Display, RESET as follows:

"TG Overview" Display

1) ENSURE the main turbine HP stop valves are closed.

- ☐ • HPT STOP VLV 1 (SV1)
- ☐ • HPT STOP VLV 2 (SV2)
- ☐ • HPT STOP VLV 3 (SV3)
- ☐ • HPT STOP VLV 4 (SV4)

_______ / _______
Initials Date

[C] TURBINE OVERSPEED TEST

20 A. 2) VERIFY EH Converter position indicates CLOSED.

“Load Detail” Display

a) VERIFY EHC CH #1 OR EHC CH #2 at least NEGATIVE 80% OR more negative:

☐ • EHC CH #1
OR

☐ • EHC CH #2

☐ b) IF at least one converter is NOT at least NEGATIVE 80% OR more negative, THEN
NOTIFY Prompt Team to investigate.

_______/_______
Initials Date

> NOTE: When the Turbine is latched above 550 rpm, a run time exceeded step 9 (Release Speed Control Reset) alarm may come in due to the Abort Rollup holding out Speed control.

On the "TG Control" Display in the “Start-up” Section

3) LATCH the Turbine as follows:

☐ a) CLICK the Turbine Latch Subgroup Controller to bring up the “Osd”

☐ b) CLICK “0/1" then Execute to turn on the Controller.

> NOTE: The Subgroup Controller should start to blink when the following step is complete. It will continue to blink until the Stop Valves are open.

☐ c) In the “Osd” CLICK “1" then Execute to start the Latching of the Turbine.

_______/_______
Initials Date

B. On the TG Control Display, VERIFY the turbine trip is reset (“Turbine Trip” Bar white).

_______/_______
Initials Date

ATTACHMENT 4
PAGE 8 OF 10

[C] TURBINE OVERSPEED TEST

20.

C. VERIFY the following parameters:

Main Control Board

- ☐ ● 1-PI-6559, TURB L/O PRESS - >25 psig.
- ☐ ● 1-PI-6561, EHC FLUID PRESS - Minimum 114 psig.
- ☐ ● 1-PI-6566, HP EHC FLUID PRESS -Approximately 455 psig.

TG Overview Display

- ☐ ● HPT CTRL VLV 1 POSN - 0%
- ☐ ● HPT CTRL VLV 2 POSN - 0%
- ☐ ● HPT CTRL VLV 3 POSN - 0%
- ☐ ● HPT CTRL VLV 4 POSN - 0%
- ☐ ● HPT STOP VLV 1 - CLOSED
- ☐ ● HPT STOP VLV 2 - CLOSED
- ☐ ● HPT STOP VLV 3 - CLOSED
- ☐ ● HPT STOP VLV 4 - CLOSED
- ☐ ● LPT 1 LP CTRL VLV 1 POSN - 0%
- ☐ ● LPT 1 LP CTRL VLV 2 POSN - 0%
- ☐ ● LPT 2 LP CTRL VLV 1 POSN - 0%
- ☐ ● LPT 2 LP CTRL VLV 2 POSN - 0%
- ☐ ● LPT 1 LP STOP VLV 1 - CLOSED
- ☐ ● LPT 1 LP STOP VLV 2 - CLOSED
- ☐ ● LPT 2 LP STOP VLV 1 - CLOSED
- ☐ ● LPT 2 LP STOP VLV 2 - CLOSED

_______ / _______
Initials Date

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[C] TURBINE OVERSPEED TEST

20. D. PERFORM the following steps to open the high pressure and low pressure stop valves:

☐ 1) CLOSE 1-HS-2417, HP CTRL VLV 1●4 BEF SEAT DRN VLV (1-CB-10)

☐ 2) On the “TG Control” Display in the “Start-Up” Section, TURN ON the “Open Stop Valves” Subloop Controller.

3) On the TG Overview Display, VERIFY HP and LP Stop Valves are OPEN:

☐ • LPT 1 LP STOP VLV 1

☐ • LPT 2 LP STOP VLV 1

☐ • LPT 1 LP STOP VLV 2

☐ • LPT 2 LP STOP VLV 2

☐ • HPT STOP VLV 1 (SV1)

☐ • HPT STOP VLV 3 (SV2)

☐ • HPT STOP VLV 2 (SV3)

☐ • HPT STOP VLV 4 (SV4)

☐ 4) OPEN 1-HS-2417, HP CTRL VLV 1.4 BEF SEAT DRN VLV (1-CB-10)

_______ / _______
Initials Date

> NOTE: Speed Target can not be reset until actual Turbine Speed is less than 550 rpm. (Abort Roll up is clear)

E. On the “TG Control” Display in the “Speed Control” Section, ROLL the Main Turbine to approximately 500 RPM by ensuring the“Speed Target” Controller to 500 RPM.

_______ / _______
Initials Date

F. RETURN TO Step 5.1.21.

_______ / _______
Initials Date

ATTACHMENT 4
PAGE 10 OF 10

[C] TURBINE OVERSPEED TEST

21. IF turbine is to be allowed to coast down to turning gear,
THEN
PERFORM the following:

A. WHEN 1-PI-6558 TURB L/O PMP DISCH PRESS is approximately 100 psig,
THEN
ENSURE at least two Auxiliary Oil Pumps start:

☐ • 1-HS-3287, TURB AUX L/O PMP A

☐ • 1-HS-3288, TURB AUX L/O PMP B

☐ • 1-HS-3289, TURB AUX L/O PMP C

_______/_______
Initials Date

B. WHEN turbine speed is approximately 1400 RPM,
THEN
PLACE the EXCITER AIR DRIER and EXCITER HEATER in ON at the Unit 1 GENERATOR AUXILIARIES CABINET JC91.

_______/_______
Initials Date

C. WHEN turbine speed is approximately 510 RPM,
THEN
ENSURE 1-HS-6579, TURB SHAFT LIFT OIL PMP starts.

_______/_______
Initials Date

D. On the “TG Lube Oil” Display, WHEN turbine speed is approximately 230 RPM,
THEN
ENSURE Turning Gear Valve #1 is OPEN.

_______/_______
Initials Date

CAUTION: The turbine generator should not be synchronized until the turbine overspeed trip devices have been satisfactorily tested.

E. RETURN TO Step 5.1.15 of IPO-003A to reset the turbine and resume turbine generator startup.

_______/_______
Initials Date

COMMENTS: ____

____

____

ATTACHMENT 5
PAGE 1 OF 5

PREPLANNED OUTAGE ACTIVITIES

NOTE: Integrated training with the Refueling Team, including Westinghouse personnel, should be completed prior to each set of back-to-back outages. An entry has been made in the Daily Activities database to trigger performance of this activity at **approximately 6 to 8 weeks** prior to the first refueling outage of a pair of outages.

A. WHEN an outage is planned for refueling operation,
THEN
PERFORM the following actions prior to the scheduled shutdown:

- Approximately 6 to 8 weeks prior to the outage, CONTACT Core Performance Engineering to determine the estimated end of cycle boron concentration. This determination will inform whether or not PM-327454 is desired per SOP-106A section 5.1.
IF the PM will be required (use of BTRS)
THEN
Notify the Work Week Coordinator. ________/________
Initials Date

At four weeks prior:

- NOTIFY Chemistry to verify RWST chemistry parameters are within specification per CHM-120. ________/________
Initials Date
- IF RWST chemistry parameters are not within specification,
THEN
INITIATE purification of Unit 1 RWST per SOP-506. ________/________
Initials Date
- ENSURE adequate RCS filters, seal injection filters and SFP Demin filters will be available for replacement during RCS cleanup activities which occur following boration to Refueling conditions. ________/________
Initials Date
- ENSURE Argon trailer has been ordered/delivered. ________/________
Initials Date
- ENSURE OPT-205A, section 8.4.2 or 8.4.4 is scheduled with RWPP in service and available for RWST cleanup, Post Testing in response to OE 18013 for sediment concerns in the RWST.
(REF: EV-CR-2011-4532-4, corrective action) ________/________
Initials Date
- IF SFP average temperature is >10°F above SSI temperature,
THEN
PLACE the second train of SFP cooling in service to both SFPs per SOP-506. ________/________
Initials Date

ATTACHMENT 5
PAGE 2 OF 5

PREPLANNED OUTAGE ACTIVITIES

NOTE:
- Normally all CCW, CW, TPCW, and CHS supplied equipment will be aligned to the non-outage unit. Exceptions should be explained by the responsible WWM and the reason.
- Notify Chemistry prior to beginning CCW unit shifts to allow additional Hydrazine monitoring as dead legs are valved in.

- Begin alignment of common equipment to the non-outage unit.:
  1. Use Attachment 5A to document all common equipment realignment.
  2. Circle the Unit which will supply that equipment.
  3. Initial and date for each equipment realignment.
  4. Contact the Work Window Managers to determine any equipment that will not be realigned. Any equipment that will need to be aligned to the outage for testing or other reasons, prior to the associated work window starting; will need to be explained in the comments section.

_______/_______
Initials Date

B. **Approximately 21 days** prior to the outage, ENSURE RHR has been borated to the desired concentration per SOP-102A.

- RHR TRAIN A _______/_______ Initials Date

- RHR TRAIN B _______/_______ Initials Date

C. **Approximately 14 days** prior to the outage PERFORM the following:

- REVIEW the Demineralizer and Filter Status with Chemistry. _______/_______ Initials Date

- IF work is planned in the letdown orifice room,
  THEN
  COMMENCE alternating the 75 gpm orifices to eliminate the crud trap and lower the associated dose rates for the scheduled work. _______/_______ Initials Date

ATTACHMENT 5
PAGE 3 OF 5

PREPLANNED OUTAGE ACTIVITIES

D.. WHEN an outage is planned, which will result in opening the RCS (i.e., RCP seal maintenance, SG tube plugging),
THEN
PERFORM the following action **approximately one week** prior to the scheduled shutdown:

- COMMENCE purging the VCT gas space per the startup section of RWS-201 to reduce RCS radioactive gas inventory. ______/______ Initials Date

E. WHEN an outage is planned which will result in MODE 5 entry OR require the Steam Generators to be drained,
THEN
PERFORM the following actions **approximately one week** prior to the scheduled shutdown:

- PERFORM both OPT-210 and OPT-213 fan and charcoal bed runs for both trains during the week before a scheduled outage such that painting and the use of chemicals will not conflict with normal outage activities. ______/______ Initials Date
- ENSURE work activities are completed on the water treatment plant so that water production capability will be maximized. ______/______ Initials Date
- ENSURE the DWST and CST water inventories are maintained at the maximum practical level. ______/______ Initials Date
- NOTIFY Chemistry to verify CST chemistry parameters are within specification per CHM-130 OR initiate actions to restore CST chemistry parameters within specification. ______/______ Initials Date
- HAVE Chemistry add Hydrazine to both trains of RHR ______/______ Initials Date
- NOTIFY the Day Shift Supervisor to schedule (per the Shift Order) a safety OMOP Blitz during the outage ______/______ Initials Date
- ENSURE BAT X-01 approximately 95%. ______/______ Initials Date
- ENSURE BAT X-02 approximately 95%. ______/______ Initials Date
- INITIATE actions to pre-stage AME Pump per Attachment 19 prior to MODE 5 entry. ______/______ Initials Date |

ATTACHMENT 5
PAGE 4 OF 5

PREPLANNED OUTAGE ACTIVITIES

F. **Approximately one week** prior to a refueling outage:

- ENSURE both trains of SFP cooling are in service per SOP-506. Contact the Operations Fuel Handling Coordinator to determine preferred lineup.

  ________/________
  Initials Date

G. WHEN an outage is planned which will result in MODE 5 entry and the RCS will be opened for maintenance activities,
THEN
PERFORM the following actions approximately 24 hours prior to MODE 3 entry:

- CONTACT Chemistry to increase monitoring of RCS hydrogen concentration.

  ________/________
  Initials Date

- REDUCE VCT hydrogen overpressure to 15 psig (or the pressure required Chemistry or Rad Waste) per SOP-103A.

  ________/________
  Initials Date

- ESTABLISH AND MAINTAIN RCS hydrogen concentration as required by Chemistry.

  ________/________
  Initials Date

- PLACE BAT X-01 in recirc

  ________/________
  Initials Date

H. **Approximately 72 hours** prior to the outage, CONTACT Chemistry, Radwaste Supervisor and NSSS WWM to sample the PRT to ensure Oxygen content is less than 2%.

  ________/________
  Initials Date

I. **Approximately 36 hours** prior to the outage, ENSURE that ALL required common equipment has been swapped to the non-outage unit. Any equipment that has been excepted by the responsible WWM should be noted in the comments section. A Unit log entry should be made to note that the system alignments are complete.

  ________/________
  Initials Date

- REMOVE the Protective Train signs from both Units

  ________/________
  Initials Date

- PROVIDE a copy of the equipment alignment list to the non-outage Unit Supervisor and the OCC WWMs.

  ________/________
  Initials Date

J. **Approximately 24 hours** prior to the outage, ESTABLISH a nitrogen atmosphere on the RCDT per SOP-110A. This activity will require pre-staging a nitrogen bottle (SOP-512).

  ________/________
  Initials Date

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PREPLANNED OUTAGE ACTIVITIES

K. **Approximately 24 hours** prior to the outage, or **sooner**, HAVE Maintenance swap lead regulators for the 150 psig and 50 psig Auxiliary Steam System to Unit 2.

_______/_______
Initials Date

L. **Day Shift** just prior to outage - PERFORM the following:

- After transitoning to Super Crews, the Dayshift EWWM PERFORM a detailed procedural walkdown with all involved NEO's of placing the APDG's in service.
- ETP-908 IRC Outside Bioshield (IPO-010 Requirement)
- OWI-409 Equipment Rotations (early vice wasting manpower Sunday)

_______/_______
Initials Date

M. **Night Shift** just prior to outage - PERFORM the following:

- ALIGN SGBD as directed by Operations and Chemistry Management. Circle Effluent flowpath:

  CST Main Condenser Heater Drain Tank

- START 2nd CCP and CCW pump
- PERFORM OPT-104 Operations Weekly Surveillances
- HAVE Chemistry do Tech Spec Sample on Unit 1 RWST (in case don't have an easy way to recirc and sample the RWST)
- After transitioning to Super Crews, the Nightshift EWWM PERFORM a detailed procedural walkdown with all involved NEO's of placing the APDG's in service.
- ALIGN Demin Water to Unit 1 Cntmt IAW SOP-507, section 5.1.4
- HAVE Chemistry sample BAT X-01

_______/_______
Initials Date

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PREPLANNED EQUIPMENT ALIGNMENT ACTIVITIES

NOTE: This Attachment is for TRACKING PURPOSES ONLY and is NOT to be used for configuration control. Any component manipulations are performed using the applicable procedures. (*) Signifies normal alignment. Those components that do not contain an (*) have no preferred alignment. Components with no preferred alignment are typically aligned just prior to an outage to the non-outage unit. If no other problems are encountered after the outage is complete, the alignment is normally left in this condition until the next outage.

MCC/PANEL	LOCATION	SUPPLIED FROM		Init/Date
XA1	SWGR 810	UNIT1 (1ST)	UNIT 2 (2ST)	
XEB1-1	AB 852	UNIT 1	UNIT 2	
XEB1-2	AB 852	UNIT 1	UNIT 2	
XEB1-3	AB 810	UNIT 1	UNIT 2	
XEB2-1	ECB 854	UNIT 1	UNIT 2	
XEB2-2	AB 852	UNIT 1	UNIT 2	
XEB3-1	FB 838	UNIT 1	UNIT 2	
XEB3-2	AB 852	UNIT 1	UNIT 2	
XEB3-3	SWIS 796	UNIT 1	UNIT 2	
XEB4-1	FB 810	UNIT 1	UNIT 2	
XEB4-2	AB 852	UNIT 1	UNIT 2	
XEB4-3	SWIS 796	UNIT 1	UNIT 2	
XB1-1	TB 803	UNIT 1	UNIT 2	
XB1-2	AB 810	UNIT 1	UNIT 2	
XB1-3	AB 873	UNIT 1	UNIT 2	
XB2-1	TB 803	UNIT 1	UNIT 2	
XB2-2	AB 810	UNIT 1	UNIT 2	
XB2-3	ECB 854	UNIT 1	UNIT 2	
XB3-1	ECB 854	UNIT 1	UNIT 2	
XB3-2	CWIS	UNIT 1	UNIT 2	
XB3-3	ECB 854	UNIT 1	UNIT 2	
XB3-4	AB 873	UNIT 1	UNIT 2	
XB3-5A	TB 778	UNIT 1	UNIT 2	
XB3-5B	TB 778	UNIT 1	UNIT 2	
XB4-1	ECB 854	UNIT 1	UNIT 2	
XB4-4	AB 873	UNIT 1	UNIT 2	
XEC1-1	ECB 807	UNIT 1	UNIT 2	
XEC2-1	ECB 807	UNIT 1	UNIT 2	
XC2-1	ECB 807	UNIT 1	UNIT 2	
XC3-1	AB 810	UNIT 1	UNIT 2	
XC5-1	ECB 807	UNIT 1	UNIT 2	
XC6-1	ECB 807	UNIT 1	UNIT 2	
XED1-1	ECB 792	UNIT 1	UNIT 2	

ATTACHMENT 5A
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PREPLANNED EQUIPMENT ALIGNMENT ACTIVITIES

MCC/PANEL	LOCATION	SUPPLIED FROM		Init/Date
XED2-1	ECB 792	UNIT 1	UNIT 2	
XD2-1	ECB 778	UNIT 1	UNIT 2	
XD2-2	TB 778	UNIT 1	UNIT 2	
XD2-3	ECB 792	UNIT 1	UNIT 2	
SAFETY CHILLED WATER				**Init/Date**
SFP X-01 RM CLG FN CHS FROM		U1 TRN A (*)	U2 TRN A	
SFP X-02 RM CLG FN CHS FROM		U1 TRN B	U2 TRN B (*)	
COMPONENT COOLING WATER				**Init/Date**
UPS X-01 CCW FROM		U1 TRN A (*)	U2 TRN A	
UPS X-02 CCW FROM		U1 TRN B	U2 TRN B (*)	
CR HVAC X-01 CCW FROM		U1 TRN A (*)	U2 TRN A	
CR HVAC X-02 CCW FROM		U1 TRN A	U2 TRN A (*)	
CR HVAC X-03 CCW FROM		U1 TRN B (*)	U2 TRN B	
CR HVAC X-04 CCW FROM		U1 TRN B	U2 TRN B (*)	
BRS EVAP CCW FROM		U1	U2 (*)	
FD WASTE EVAP CCW FROM		U1 (*)	U2	
WASTE EVAP CCW FROM		U1	U2 (*)	
VENT CHLR X-01 CCW FROM (NOTE 2)		U1(*)	U2	
VENT CHLR X-02 CCW FROM (NOTE 2)		U1(*)	U2	
VENT CHLR X-03 CCW FROM (NOTE 2)		U1	U2(*)	
VENT CHLR X-04 CCW FROM (NOTE 2)		U1	U2(*)	
WGC X-01 CCW FROM		U1	U2	
WGC X-02 CCW FROM		U1	U2	
H2 RECOMBINER X-01 CCW FROM		U1	U2	
H2 RECOMBINER X-02 CCW FROM		U1	U2	

ATTACHMENT 5A
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PREPLANNED EQUIPMENT ALIGNMENT ACTIVITIES

CIRCULATING WATER					**Init/Date**
VENT CHLR X-05 & X-06 CW FROM (NOTE 1)	U1(*)		U2		
VENT CHLR X-07, X-08 & X-09 CW FROM (NOTE 1)	U1		U2(*)		
STATION SERVICE WATER					**Init/Date**
SSW SCRNWSH PMP X-01 SPLY FROM	U1 TRN A		U2 TRN A		
SSW SCRNWSH PMP X-02 SPLY FROM	U1 TRN B		U2 TRN B		
SSW CORROSION INHIBITOR, DISPERSANT & CLAMICIDE DILUTION SPLY FROM SSW	U1 TRN A	U1 TRN B	U2 TRN A	U2 TRN B	
TURBINE PLANT COOLING WATER					**Init/Date**
SOP-313A Section 5.8 or 5.9 complete	U1		U2(*)		
TPCW FILTER DEMIN SKID	U1		U2		
INSTRUMENT AIR COMPRESSOR X-01 POWER SUPPLY					**Init/Date**
INST AIR COMP X-01	1B4		2B4		

DATE	**COMMENTS**	**Initial**

ATTACHMENT 5A
PAGE 4 OF 4

PREPLANNED EQUIPMENT ALIGNMENT ACTIVITIES

NOTE 1: Circ Water to Vent Chillers X-05 thru X-09 should NOT be swapped until 36 hours prior to the outage due to the low suction pressure seen by the pumps when they are realigned.
NOTE 2: Vent Chiller X-01 thru X-04 CCW supply should remain the normal configuration. This will allow the u-HV-4650A/B valves to be stroked.

ATTACHMENT 6
PAGE 1 OF 3

OPT-217A POWER REDUCTION

CAUTION: During OPT-217A, steam pressure fluctuations may occur during valve strokes.

NOTE:
- Core Performance Engineering should be informed of any substantial reduction in power (>25%).
- Turbine power should be 875 (870-880) MWE or as directed by Operations Management prior to cycling control valves.

1. NOTIFY QSE Generation Controller AND UPDATE GAPS to “Create Current” from the “Forecasted Condition” prior to reducing load.
   ______/______ Initials Date

[C]
2. IF Reactor power will be decreased by $\geq$15% within a one hour period, THEN NOTIFY Chemistry and Radiation Protection. (TS SR 3.4.16.2, ODCM 4.11.2.1.1.2, 4.11.2.1.1.3)
   ______/______ Initials Date

NOTE:
- For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the reactivity plan. |
- Primary plant should lead secondary plant during Main Turbine load changes.

3. CALCULATE the amount of boration required to reduce Reactor power.
   ______/______ Initials Date
4. REFER to Attachment 2 for guidance in controlling AFD during power reductions.
   ______/______ Initials Date
5. INITIATE RCS boration/dilution using SOP-104A.
   ______/______ Initials Date
6. IF desired to enhance boron mixing, ENERGIZE additional Pressurizer Backup heaters.
   ______/______ Initials Date
7. On the TG Display in the “Load Control” Section, SET in the desired unloading rate using the Load Rate Setpoint Controller.
   ______/______ Initials Date

ATTACHMENT 6
PAGE 2 OF 3

OPT-217A POWER REDUCTION

NOTE: The load will immediately begin decreasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.

8. In the "Load Control" Section, LOWER the Load Target Setpoint Controller as necessary to obtain 875 MW or the desired intermediate load to control turbine load.

   ______/______
   Initials Date

CAUTION: Control Rods should NOT be placed in automatic until the fuel is fully conditioned to 100% power.

9. WHEN Turbine load is stable at the desired power level,
   THEN
   PERFORM OPT-217A.

   ______/______
   Initials Date

CAUTION:
- Control Rods may be withdrawn at a maximum rate of 3 steps/hr above 50% until fuel conditioning has been performed as directed by Core Performance Engineering.
- Observe Fuel conditioning limits during all Reactor power increases.

NOTE:
- For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the reactivity plan.
- Primary plant should lead secondary plant during Main Turbine load changes.

10. CALCULATE the amount of dilution required to raise Reactor power to 98%.

    ______/______
    Initials Date

11. REFER to Attachment 2 for guidance in controlling AFD during the power increase.

    ______/______
    Initials Date

12. INITIATE RCS boration/dilution using SOP-104A.

    ______/______
    Initials Date

13. On the "TG" Display in the "Load Control" Section, SET in the desired loading rate using the Load Rate Setpoint Controller.

    ______/______
    Initials Date

ATTACHMENT 6
PAGE 3 OF 3

OPT-217A POWER REDUCTION

NOTE:
- The load will immediately begin increasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
- It may be necessary to raise Turbine Load in increments to maintain Ramp Rate Restrictions.

14. In the "Load Control" Section, RAISE the Load Target Setpoint Controller as necessary to obtain a Turbine Load that corresponds to 98% Rx Power while controlling the rate of Turbine power increase. ______/______ Initials Date

15. WHEN Reactor power is approximately 98%,
THEN
PERFORM a calorimetric per OPT-309. ______/______ Initials Date

CAUTION: Reactor power shall be closely monitored to avoid exceeding 100% Reactor power.

16. In the "Load Control" Section, RAISE the Load Target Setpoint Controller as necessary to maintain 3612 MWth Reactor power as indicated on the Plant Computer PPP Calorimetric (See flowchart in Section 5.5 for power limitations if PPPC is not available). ______/______ Initials Date

17. When Reactor power is at 100% or desired power level:
    - ENSURE 1/1-RBSS, CONTROL ROD BANK SELECTOR in AUTO. ______/______ Initials Date
    - NOTIFY QSE Generation Controller and update GAPS to "End Current Condition" to show that this power limitation is no longer applicable. ______/______ Initials Date

18. When improved boron mixing is no longer required, DEENERGIZE those additional Pressurizer Backup Heaters energized at Step 6. ______/______ Initials Date

19. REFER to Section 5.5 to maintain constant Turbine load. ______/______ Initials Date

COMMENTS:____

____

ATTACHMENT 6A
PAGE 1 OF 5

DOWN POWER TO APPROXIMATELY 700 MWE

NOTE:
- This section may be used for NODAL MARKET BACKDOWN or for other reasons requiring a power reduction to an intermediate value or minimum of approximately 700 MWE.
- Core Performance Engineering should be informed of any substantial reduction in power (>25%).
- Primary plant should lead secondary plant during Main Turbine load changes.

1. NOTIFY QSE Generation Controller AND UPDATE GAPS to "Create Current" from the "Forecasted Condition" prior to reducing load.

_______/_______
Initials Date

NOTE: For power changes greater than 5%, a reactivity plan should be developed using one of the sources below. (Listed in order of preference)

- IF time and resources support generation of a BEACON projection (for a pre-planned power maneuver), THEN contact Core Performance Engineering for support, and utilize the approved results as the reactivity plan.
- IF the power change closely matches one of the down-power scenarios available in the Reactivity Briefing Sheets (printed from CHORE), THEN utilize the appropriate currently approved reactivity plan (interpolation between values on the Boration Matrix is allowed).
- IF the above two options are not available or do not fit the current scenario, THEN perform a NDR based reactivity calculation per Attachment 3 or equivalent CHORE output

[C]
2. IF Reactor power will be decreased by $\geq$15% within a one hour period,
THEN
NOTIFY Chemistry and Radiation Protection.
(TS SR 3.4.16.2, ODCM 4.11.2.1.1.2, 4.11.2.1.1.3)

_______/_______
Initials Date

ATTACHMENT 6A
PAGE 2 OF 5

DOWN POWER TO APPROXIMATELY 700 MWE

NOTE:
- During the initial reduction in power, a combination of control rod insertion and boration should be used to compensate for changes in reactivity due to power defect. This will allow the control rods to be available to compensate for the reactivity due to Xenon following the power reduction.
- During a down power, operators should adjust the pots (1-SK-0509B and 1-SK-0509C) to maintain the difference between the FWPT speeds within the desirable range.
- FWPT speed deviation from commanded speed during a normal downpower may be an indication of binding in a FWPT control valve, guidance for this event is located in ABN-302 Sect. 9.0, FEEDWATER PUMP CONTROL SYSTEM MALFUNCTION.

3. PERFORM the following to reduce Turbine load to approximately 60% (700 MWE) OR the desired intermediate load:

   A. IF desired,
   THEN
   DETERMINE the amount of boration required to reduce Reactor power to approximately 60% (700 MWE) or the desired intermediate load using the appropriate currently approved Reactivity Projection.
   ________ / ________
   Initials Date

   B. IF desired,
   THEN
   DETERMINE the rate of boration required to allow slow control rod inward motion as the turbine load decreases, using the appropriate currently approved Reactivity Projection.
   ________ / ________
   Initials Date

   C. REFER to Attachment 2 for guidance in controlling AFD during power ramps.
   ________ / ________
   Initials Date

   D. INITIATE RCS boration/dilution using SOP-104A.
   ________ / ________
   Initials Date

   E. IF desired to enhance boron mixing, ENERGIZE additional Pressurizer Backup heaters.
   ________ / ________
   Initials Date

   F. On the TG Display in the “Load Control” Section, SET in the desired unloading rate using the Load Rate Setpoint Controller
   ________ / ________
   Initials Date

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DOWN POWER TO APPROXIMATELY 700 MWE

NOTE: The load will immediately begin decreasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.

3. G. In the "Load Control" Section, LOWER the Load Target Setpoint Controller as necessary to obtain 700 MWE or the desired intermediate load to control turbine load.

   ________/________
   Initials Date

   H. IF MSR's are to be removed from service,
   THEN
   OPEN:

   - 1HD-0933, HTR DRN SYS MSR 1-A XS HTG STM ORIF UPSTRM ISOL VLV
   - 1HD-0937, HTR DRN SYS MSR 1-B XS HTG STM ORIF UPSTRM ISOL VLV

   ________/________
   Initials Date

   I. STABILIZE Turbine load at desired power level UNTIL released to return to 100%.

   ________/________
   Initials Date

CAUTION:
- Observe Fuel conditioning limits during all Reactor power increases.
- Control Rods should NOT be placed in automatic until the fuel is fully conditioned to 100% power.

NOTE:
- For power changes greater than 5%, a reactivity plan should be developed (BEACON, CHORE or NDR reactivity calculation). When calculating the boration/dilution volume refer to note 4.2.24 to determine the source of the reactivity plan.
- Primary plant should lead secondary plant during Main Turbine load changes.

4. PERFORM the following to raise Reactor power to 98%:

   A. IF desired,
   THEN
   DETERMINE the amount of dilution required to raise Reactor power to approximately 98% using the appropriate currently approved Reactivity Projection.

   ________/________
   Initials Date

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DOWN POWER TO APPROXIMATELY 700 MWE

4. B. IF desired,
THEN
DETERMINE the rate of dilution required to allow slow control rod outward motion as the Turbine load increases, using the appropriate currently approved Reactivity Projection.

_______/_______
Initials Date

C. REFER to Attachment 2 for guidance in controlling AFD during power increases.

_______/_______
Initials Date

D. INITIATE RCS boration/dilution using SOP-104A.

_______/_______
Initials Date

E. In the “Load Control” Section, SET in the desired loading rate using the Load Rate Setpoint Controller.

_______/_______
Initials Date

NOTE:
- The load will immediately begin increasing to the setpoint value at the rate set on the Load Rate Setpoint Controller. The LOAD RATE may be readjusted as necessary.
- It may be necessary to raise Turbine Load in increments to maintain Ramp Rate Restrictions.

F. In the “Load Control” Section, RAISE the Load Target Setpoint Controller as necessary to obtain a Turbine Load that corresponds to 98% Rx Power while CONTROLLING the rate of Turbine power increase.

_______/_______
Initials Date

G. WHEN Reactor power is approximately 98%,
THEN
PERFORM a calorimetric per OPT-309.

_______/_______
Initials Date

ATTACHMENT 6A
PAGE 5 OF 5

DOWN POWER TO APPROXIMATELY 700 MWE

> CAUTION: Reactor power shall be closely monitored to avoid exceeding 100% Reactor power.

4. H. In the "Load Control" Section, RAISE the Load Target Setpoint Controller as necessary to maintain 3612 MWth Reactor power as indicated on the Plant Computer PPP Calorimetric (See flowchart in Section 5.5 for power limitations if PPPC is not available).

_______/_______
Initials Date

I. IF step 3.H was performed,
THEN
PERFORM Attachment 6B to adjust MSR excess heating steam flow.

_______/_______
Initials Date

> CAUTION: Control Rods should NOT be placed in automatic until the fuel is fully conditioned to 100% power.

J. WHEN Reactor power is at 100% or desired power level:

- ENSURE 1/1-RBSS, CONTROL ROD BANK SELECTOR in AUTO.

_______/_______
Initials Date

- NOTIFY QSE Generation Controller AND UPDATE GAPS to "End Current Condition" to show that this power limitation is no longer applicable.

_______/_______
Initials Date

K. WHEN improved boron mixing is no longer required, DEENERGIZE those additional Pressurizer Backup Heaters energized at Step 3.E.

_______/_______
Initials Date

L. REFER TO Section 5.5 to maintain constant Turbine load.

_______/_______
Initials Date

ATTACHMENT 6B
PAGE 1 OF 2

MSR EXCESS HEATING STEAM VALVE RESTORATION

> NOTE: This attachment should be used following removal from service both MSR's

1. PERFORM the following steps to adjust the Moisture Separator Reheater excess heating steam flow:

> NOTE: Due to the location of the Temperature Probes on the MSR Tubesheets, the Tubesheet temps on the MSR Display may have a difference of more than 15°F. Therefore, the MSR Tubesheet Temperatures on the EXP #2 MSR Temperatures Display may be used to determine deltaT.

A. VERIFY the difference between MSR Saturation Temp's on the "MSR" Display and MSR tubesheet temperatures are ≤15°F.

MSR 1-A (MSRL)

☐ • Saturation Temp 1-A

☐ • MSR 1-A "Tubesheet" Temperature

MSR 1-B (MSRR)

☐ • Saturation Temp 1-B

☐ • MSR 1-B "Tubesheet" Temperature

_______/_______
Initials Date

> NOTE: The final position of 1HD-0933 and 1HD-0937 is set to 1/4 to 1/8 turns from FULL SHUT in the following step, ensuring steam flow is present through orifice while preventing line surges for maximum thermal efficiency.

B. IF the temperature difference between MSR Saturation Temp's in the "MSR Setpoint" Section and tubesheet temperatures >15°F,
THEN
PERFORM the following:

1) NOTIFY System Engineering to assist in adjusting MSR excess heating steam flow.

_______/_______
Initials Date

ATTACHMENT 6B
PAGE 2 OF 2

MSR EXCESS HEATING STEAM VALVE RESTORATION

1. B. 2) ADJUST excess heating steam orifice isolation valves to establish a difference of <15°F between MSR Saturation Temp's in the "MSR Setpoint" Section and tubesheet temperatures:

MSR 1-A (MSRL)

- ☐ • 1HD-0933, HTR DRN SYS MSR 1-A XS HTG STM ORIF UPSTRM ISOL VLV
- ☐ • Saturation Temp 1-A
- ☐ • MSR 1-A "Tubesheet" Temperature

MSR 1-B (MSRR)

- ☐ • 1HD-0937, HTR DRN SYS MSR 1-B XS HTG STM ORIF UPSTRM ISOL VLV
- ☐ • Saturation Temp 1-B
- ☐ • MSR 1-B "Tubesheet" Temperature

_______/_______
Initials Date

NOTE: During initial adjustment of the MSR heating steam, the MSRs may experience surges caused by insufficient excess heating steam.

3) IF necessary to increase MSR tubesheet temperatures,
THEN
THROTTLE OPEN the heating steam orifice bypass valve.

- ☐ • 1HD-0935, HTR DRN SYS MSR 1-A XS HTG STM ORIF BYP VLV
- ☐ • 1HD-0939, HTR DRN SYS MSR 1-B XS HTG STM ORIF BYP VLV

_______/_______
Initials Date

COMMENTS: ____

____

ATTACHMENT 7
PAGE 1 OF 3

ESTABLISHING SEPARATOR DRAIN TANK NORMAL DRAIN FLOW

NOTE:
- This attachment provides a method to isolate, refill and cool separator drain tank normal drain lines to establish forward flow.
- The separator drain tanks affect pressure in the associated Heater Drain Tank. It is desired, where practical, to perform actions simultaneously when establishing flow from BOTH Separator Drain tanks.

1. ENSURE the MSR SEP DRN TK ALT LVL CTRL for the separator is in AUTO and controlling level:

   ☐ • 1-LK-2709, MSR A SEP DRN TK ALT LVL CTRL

   ☐ • 1-LK-2713, MSR B SEP DRN TK ALT LVL CTRL

   ________/________
   Initials Date

2. PERFORM the following to isolate the MSR SEP DRN TK and establish flow to fill the normal drain line:

   MSR SEPARATOR DRAIN TANK 1-A

   ☐ a) PLACE 1-LK-2708, MSR A SEP DRN TK NORM LVL CTRL in MANUAL and CLOSE.

   ☐ b) CLOSE 1HD-0721, HTR DRN SYS MSR SEP DRN TK 1-A NORM DRN LCV 2708 DNSTRM ISOL VLV.

   ☐ c) OPEN 1HD-0985, HTR DRN SYS MSR SEP DRN TK 1-A NORM DRN LN CHK VLV BYP VLV.

   ________/________
   Initials Date

   MSR SEPARATOR DRAIN TANK 1-B

   ☐ a) PLACE 1-LK-2712, MSR B SEP DRN TK NORM LVL CTRL in MANUAL and CLOSE.

   ☐ b) CLOSE 1HD-0637, HTR DRN SYS MSR SEP DRN TK 1-B NORM DRN LCV 2712 DNSTRM ISOL VLV.

   ☐ c) OPEN 1HD-0984, HTR DRN SYS MSR SEP DRN TK 1-B NORM DRN LN CHK VLV BYP VLV

   ________/________
   Initials Date

3. RECORD time normal drain line isolated.

   ________/________/________
   Initials Date Time

ATTACHMENT 7
PAGE 2 OF 3

ESTABLISHING SEPARATOR DRAIN TANK NORMAL DRAIN FLOW

4. IF two attempts have been made to establish flow AND flow is still NOT established,
   THEN
   CONTACT System Engineer for direction.

   ______/______
   Initials Date

5. WHEN the line has been isolated for 12 - 24 hours,
   THEN
   PERFORM the following to establish forward flow from the Separator Drain Tank:

   MSR SEPARATOR DRAIN TANK 1-A

☐ a) CLOSE 1HD-0985, HTR DRN SYS MSR SEP DRN TK 1-A NORM DRN LN CHK VLV BYP VLV.

☐ b) OPEN 1HD-0721, HTR DRN SYS MSR SEP DRN TK 1-A NORM DRN LCV 2708 DNSTRM ISOL VLV.

☐ c) Slowly OPEN 1-LK-2708, MSR SEP DRN TK NORM LVL CTRL VLV to approximately 20% open in 4 equal steps of approximately 5% with a 30 second delay between each step.

NOTE:	Per EV-CR-2013-011413, the previous time of ~ 30 minutes was based on operator experience. At 20% demand a longer time will likely be required. There is no time requirement in the analysis. Twelve hours is arbitrarily chosen; operator discretion is allowed for reperforming steps 2-5 earlier if desired or later than twelve hours if necessary. Alternate level control valve response should be closely monitored.

☐ d) IF 1-LK-2709, MSR A SEP DRN TK ALT LVL CTRL does not begin closing after a reasonable time (up to 12 hours)
   AND
   1-LK-2708, MSR A SEP DRN TK NORM LVL CTRL is still approximately 20% open
   THEN
   REPERFORM Steps 2 through 5.

   ______/______
   Initials Date

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ESTABLISHING SEPARATOR DRAIN TANK NORMAL DRAIN FLOW

5. MSR SEPARATOR DRAIN TANK 1-B

☐ a) CLOSE 1HD-0984, HTR DRN SYS MSR SEP DRN TK 1-B NORM DRN LN CHK VLV BYP VLV.

☐ b) OPEN 1HD-0637, HTR DRN SYS MSR SEP DRN TK 1-B NORM DRN LCV 2712 DNSTRM ISOL VLV

☐ c) Slowly OPEN 1-LK-2712, MSR SEP DRN TK NORM LVL CTRL VLV to approximately 20% open in 4 equal steps of approximately 5% with a 30 second delay between each step.

> NOTE: Per EV-CR-2013-011413, the previous time of ~ 30 minutes was based on operator experience. At 20% demand a longer time will likely be required. There is no time requirement in the analysis. Twelve hours is arbitrarily chosen; operator discretion is allowed for reperforming steps 2-5 earlier if desired or later than twelve hours if necessary. Alternate level control valve response should be closely monitored.

☐ d) IF 1-LK-2713, MSR B SEP DRN TK ALT LVL CTRL does not begin closing after a reasonable time (up to 12 hours)
AND
1-LK-2712, MSR A SEP DRN TK NORM LVL CTRL is still approximately 20% open
THEN
REPERFORM Steps 2 through 5.

________/________
Initials Date

6. WHEN level is stable AND the MSR SEP DRN TK ALT LVL CTRL valve is closed,
THEN ZERO the controller deviation
AND
PLACE the MSR SEP DRN TK NORM LVL CTRL in AUTO
AND
ENSURE level is maintained

☐ • 1-LK-2708, MSR A SEP DRN TK NORM LVL CTRL

☐ • 1-LK-2712, MSR B SEP DRN TK NORM LVL CTRL

________/________
Initials Date

COMMENTS:____

____

ATTACHMENT 8
PAGE 1 OF 4

PLANNED TRIP DATA COLLECTION

NOTE: Data is to be collected for review from any source which provides adequate information to allow assessment of the performance of the following equipment.

Using applicable Informational Sources listed below, verify the capability to determine the performance of each of the following:

1. Reactor Trip Breakers
2. Feed Water Isolation Valves
3. Main Turbine Trip
4. Main Generator Output Breakers
5. Auxiliary Feed Water
6. Steam Dumps/Atmospheric Relief Valves

INFORMATIONAL SOURCES

NOTE:
- Computer printouts and hard copies of PCS Group Display plots may be used in place of MCB recorders. I&C should be consulted to generate and obtain computer history files, if required.
- Only the Alarm Printout, Post Trip Review, and Sequence of Events Printout are required. Other printouts and data are only required to be collected as needed to evaluate unexpected plant responses.
- The Post Trip Review printout will NOT automatically initiate if the Unit is tripped from MODE 2 conditions. SOP-906 provides instructions which allows the Post Trip Review trigger conditions to be modified or the printout to be manually initiated.

Collect the following printouts, recorder traces, and documentation, as applicable, to complete the evaluation of plant performance during the planned trip.

1. Plant Computer
   - Alarm Printout
   - Post Trip Review
   - Applicable Logs

ATTACHMENT 8
PAGE 2 OF 4

PLANNED TRIP DATA COLLECTION

2. Sequence of Events Recorder
3. 1-NR-45 Power Range & ΔI recorder
4. 1-PR-437 RCS Wide Range Pressure recorder
5. 1-TR-412 Tave/Tref recorder
6. 1-TR-413A/23A & 433A/43A RCS HL Temperature recorders
7. 1-TR-413B/23B & 433B/43B RCS CL Temperature recorders
8. 1-FR-510 SG #1 Lvl, Steam Flow, & Feed Flow recorder
9. 1-FR-520 SG #2 Lvl, Steam Flow, & Feed Flow recorder
10. 1-FR-530 SG #3 Lvl, Steam Flow, & Feed Flow recorder
11. 1-FR-540 SG #4 Lvl, Steam Flow, & Feed Flow recorder
12. 1-FR-157 RCP #1 Seal Injection & Leakoff recorder
13. 1-FR-156 RCP #2 Seal Injection & Leakoff recorder
14. 1-FR-155 RCP #3 Seal Injection & Leakoff recorder
15. 1-FR-154 RCP #4 Seal Injection & Leakoff recorder
16. 1-LR-459 Przr Level recorder
17. Step Counters
18. Computer TREND file
19. PC-11 Alarm Printers
20. Gen 1/2 Gross MW Turbine load recorder
21. 1-UDR-760/761 Plant Computer analog trend recorders
22. 1-TR-612/613 RHR Flow/Temperature recorder
23. 1-TR-411 N16/OPSP/OTSP recorder
24. X-FR-1 Power Station Frequency

ATTACHMENT 8
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PLANNED TRIP DATA COLLECTION

COMPUTER HISTORY FILE

NOTE: The Prompt Team should be consulted to setup and generate computer history files for the listed points as needed to evaluate any unexpected plant response.

Description	Plant Computer Point ID Train A	Train B
Reactor Trip	Y6506D	Y6825D
CCP In Service	Y6522D	Y6523D

Description	Plant Computer Point ID
Reactor Power- S.R.	N6101A, N6201A
- I.R.	N6033A, N6036A
- P.R.	N6049A, N6050A, N6051A, N6052A
RCS Pressure- PRZR	P6480A, P6483A, P0481A, P0482A
- RCS Loop	P6499A, P6498A, P6487A
PRZR Safeties	Y6460D, Y6775D, Y6461D
PRZR Level	L6480A, L6481A, L6482A, L6468A
PRZR PORVs	Y6469D, Y6780D
Subcooling Margin	T6611A, T6612A
PRT Pressure	P6485A
PRT Level	L6485A

RCS LOOP	1	2	3	4
T_{cold}	T0402A	T0422A	T0442A	T0462A
T_{hot}	T6419A	T6439A	T6459A	T6479A
Tave	T0400A	T0420A	T0440A	T0460A
SG Level	L6403A	L6423A	L6443A	L6463A
Steam Flow	F6406A	F6426A	F6446A	F6466A
Feed Flow	F6404A	F6424A	F6444A	F6464A
AFW Flow	F6407A	F6427A	F6447A	F6467A
SG Atmospherics	Y6703D	Y6845D	Y6704D	Y6846D
MSL Pressure	P6400A	P6420A	P6440A	P6460A
N16 PWR Channel	T6503A	T6523A	T6543A	T6563A

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PLANNED TRIP DATA COLLECTION

COMPUTER HISTORY FILE (Continued)

SAFEGUARD BUS VOLTAGE

Description	Plant Computer Point ID
1EB1 Voltage	V6301A
1EB2 Voltage	V6302A
1EB3 Voltage	V6303A
1EB4 Voltage	V6304A

CALORIMETRIC

Description		Plant Computer Point ID
REACTOR TOTAL THERMAL C30M Q	(MW)	U3452
REACTOR TOTAL THERMAL C8H Q	(MW)	U3453
REACTOR TOTAL THERMAL C15M Q	% - VENTURI	U3454
REACTOR TOTAL THERMAL C30M Q	% - VENTURI	U3455
REACTOR TOTAL THERMAL C8H Q	% - VENTURI	U3456
RX TOTAL THERMAL (LEFM) C15M Q	(MW) - LEFM	U3465
RX TOTAL THERMAL (LEFM) C30M Q	(MW) - LEFM	U3466
RX TOTAL THERMAL (LEFM) C8H Q	(MW) - LEFM	U3467
RX TOTAL THERMAL (LEFM) C15M Q	% - VENTURI CORRECTED FOR LEFM	U3468
RX TOTAL THERMAL (LEFM) C30M Q	% - VENTURI CORRECTED FOR LEFM	U3469
RX TOTAL THERMAL (LEFM) C8H Q	% - VENTURI CORRECTED FOR LEFM	U3470

FEEDWATER ISOLATION & VALVE CLOSURE

Description Plant Computer Point ID

Description	Train A	Train B
Feedwater Isolation Signal	Y6486D	Y6908D
1-HV-2134	Y6434D	Y6747D
1-HV-2135	Y6435D	Y6750D
1-HV-2136	Y6941D	Y6754D
1-HV-2137	Y6438D	Y6756D

ATTACHMENT 9
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PLANNED TRIP OPERATIONS BRIEFING

- The expected basic flowpath following the trip will be as follows:

  1) ENTER into EOP-0.0A and perform immediate operator actions.

  2) TRANSITION to EOS-0.1A.

     - STABILIZE the RCS temperature at no-load conditions
     - ESTABLISH AFW control
     - ESTABLISH no-load pressurizer pressure and level
     - ESTABLISH steam pressure mode for steam dumps (Instructions for establishing steam pressure mode are available in IPO-009A)
     - TRANSITION to IPO-005A or IPO-007A while performing IPO-009A concurrently

  3) PERFORM IPO-009A.

     - ADJUST AFW flow to establish normal SG level
     - MONITOR AND SHUTDOWN the running MFW pump
     - MONITOR the turbine during coastdown
     - SHUTDOWN AND ALIGN main generator/transformer systems
     - VERIFY TSLB, ALB, and PCIP indications
     - TRANSITION to IPO-005A or IPO-007A

- DISCUSS expected plant response following the opening of the Reactor Trip Breakers. Include automatic actions expected to occur, such as turbine trip, generator trip, and feed water isolation.

- DISCUSS the Generator Output breakers should trip following a pre-set time delay of approximately 12 seconds. If the Generator Output breakers do not open following a trip, the Generator Output breakers should be opened.

- DISCUSS expected actions and responsibilities of individual operators. Include a discussion of those local operator actions which will be required during the shutdown and subsequent reactor trip.

- REVIEW EOP-0.0A immediate operator actions and Foldout Page items. Emphasize that although this is a planned trip, EOP rules of usage apply as soon as entry is made to EOP-0.0A and continue to apply until EOPs are declared to be no longer in effect.

ATTACHMENT 9
PAGE 2 OF 2

PLANNED TRIP OPERATIONS BRIEFING

- DISCUSS change in SG level control band following transition to the EOP network from this procedure. Emphasize establishing required level control band of 43% - 60% in a controlled, deliberate manner. Consider manually establishing AFW flow at the minimum flow required to remove heat and make up for SG Blowdown flow following the completion of the immediate operator actions of EOP-0.0A (per ODA-407) to allow maintaining SG level in the high end of the control band.

- DISCUSS change in SG level control band following transition to IPO-005A and IPO-009A from the EOP network. Emphasize establishing required level control band of 60% - 75% in a controlled, deliberate manner due to the potential for an excessive feed rate causing a drop in RCS temperature. A drop in RCS temperature will cause a drop in RCS pressure and potential low pressure Safety Injection.

- CONSIDER the status of SG Blowdown when establishing AFW flow rates. AFW flow rate must be adjusted to makeup for blowdown flow and provide adequate RCS heat removal.

- AFW cannot be started per SOP-304A with Reactor power greater than 10% without entering an LCO.

- IF an AFW automatic actuation occurs, CONTACT Licensing to determine if it should be considered a reportable ESF actuation.

- Steam dumps should be MONITORED to ensure RCS temperature is being maintained at no-load temperature following the reactor trip.

- Although SG shrink and swell effects will not be as severe as following a trip from full power, these effects should still be considered and any changes in feed and/or steaming rate following the trip should be made in a slow, deliberate manner.

- REVIEW applicable portions of Operations Guideline No. 3, Attachment 1 for expectations regarding Reactivity Management issues.

ATTACHMENT 10
PAGE 1 OF 1

STATOR BAR MONITORING DATA

NOTES:

- The Stator Bar Monitoring fingerprint data previously taken by Shift Operations will now be taken by Engineering personnel per PPT-P1-5004, Stator Bar Monitoring Fingerprint Test. Baseline data will be collected at 4 different power levels after steady state Main Generator conditions are established per PPT-P1-5004.

- The Stator Bar Monitor Generator Temperature Analyzer (GTA) has two modes of operation which are Continuous and Fingerprint.

- During steady state operation, the GTA provides continuous monitoring of 168 stator bar outlet temperatures. The continuous monitoring entails automatic initiation of a measuring cycle every 30 minutes.

- Steady state conditions are defined by the GTA as follows:

  - Stator current ± 200 amps
  - Reactive power ± 10 MVAR
  - Generator Voltage ± 150 volts
  - Cold water temperature ± 0.9°F
  - Cold gas temperature ± 1.8°F
  - Differential pressure ± 5%

- To initiate a Fingerprint function, Continuous Monitoring must be stopped. To resume Continuous Monitoring, the Fingerprint function must be stopped.

- Initiating a Fingerprint function requires Admin or Superuser access.

- If the GTA detects an inadmissible temperature change, a warning or alarm is initiated and sent to the Plant Computer then to 1-ALB-10A, Window 4.12.

ATTACHMENT 11
PAGE 1 OF 1

SHUTDOWN TO MODE 3 FROM MODE 2

These instructions provide the actions to shutdown the reactor and place the Unit in MODE 3, while the Unit is operating in MODE 2 conditions.

> NOTE: Verification of adequate Shutdown Margin prior to MODE 3 entry will be satisfied by the following step. Following MODE 3 entry, RCS boron concentration shall NOT be intentionally decreased and an RCS cooldown shall NOT be intentionally initiated until adequate Shutdown Margin has been verified.

1. Within 12 hours prior to entering MODE 3, DOCUMENT Control Bank Insertion Limits have been verified per OPT-102A (TS 3.1.6). ________/________ Initials Date

2. ENSURE HIGH FLUX AT SHUTDOWN alarm blocked on both Source Range drawers.

☐ • N31, HIGH FLUX AT SHUTDOWN

☐ • N32, HIGH FLUX AT SHUTDOWN ________/________ Initials Date

3. ESTABLISH Planned Trip Data Collection as required per Attachment 8. ________/________ Initials Date

4. PERFORM pre-evolution brief for reactor trip using Attachment 9. ________/________ Initials Date

5. WHEN it is desired to trip the reactor,
THEN
PERFORM the following:

   A. OBTAIN the Shift Manager approval, AND: ________/________ Initials Date

   B. Manually TRIP the reactor, AND: ________/________ Initials Date

   C. PROCEED to EOP-0.0A
   THEN
   TRANSITION to IPO-005A OR IPO-007A AND IPO-009A, when directed. ________/________ Initials Date

   D. FILE this procedure per ODA-104. ________/________ Initials Date

COMMENTS: ____

____

IPO-003A satisfactorily completed: ____________________/__________
SHIFT MANAGER DATE

ATTACHMENT 12
PAGE 1 OF 2

INSTRUCTIONS FOR SINGLE CONDENSATE PUMP OPERATION

1. Operating experience has demonstrated that the Unit can be expected to achieve approximately 650 MW to 700 MW with a single Condensate Pump, single Main Feedwater Pump and two Heater Drain Pumps in service WHILE implementing the following operating restrictions:

   - Feedwater Pump suction pressure is limited to a minimum of 350 psig during steady state operation (administrative limit). The 350 psig limit is established to prevent bypassing the Condensate Polishing Unit and Low Pressure Heaters in the event of a trip of one of the operating Heater Drain Pumps.

   - Main Feedwater Pump discharge flow is limited to a maximum of 24,000 gpm as specified in SOP-302A.

2. Startup of the second Main Feedwater Pump during steady-state operation at 650 MW to 700 MW with a single Condensate Pump could result in low Main Feedwater Pump suction pressure and a resulting trip of the feedwater pumps.

3. If conditions require alternating Main Feedwater Pumps during Unit operation with a single Condensate Pump, the following limitations apply:

   - Unit load should be lowered to approximately 400 MW (~ 35%) in order to raise Feedwater Pump suction pressure so that the startup of the second Main Feedwater Pump will not result in a loss of Feedwater Pump suction pressure.

   - Feedwater Pump suction pressure should be maintained greater than 350 psig while alternating Main Feedwater Pumps. During the evolution, incremental reduction of Turbine load may be performed as necessary to maintain Feedwater Pump suction pressure greater than 350 psig.

   - Condensate Pump Recirculation Valve position should be monitored during the evolution to alternate Main Feedwater Pumps. If the recirc valve automatically opens during the evolution, Feedwater Pump suction pressure will decrease. If Condensate System flow decreases to less than 6000 gpm, the minimum flow for Condensate Pump protection is not available and the recirc valve should be open.

     The Condensate Pump Recirculation Valve (1-FK-2239) should be in Trip to Auto enable (to ensure minimum flow protection) AND closed (to minimize reduction of Feedwater Pumps suction pressure) during the evolution. A minimum Condensate System flow of approximately 7500 gpm should be obtained prior to opening the recirculation valve on the idle Main Feedwater Pump. As the Main Feedwater Pump forward flow to the Steam Generators increases above the feedwater flow setpoint (6000 gpm), the Feedwater Pump Recirculation valve will close and Condensate System flow will be reduced. An initial flow of 7500 gpm will prevent Condensate System flow from being reduced below the opening setpoint of the Condensate Pump Recirculation Valve (6000 gpm) as the Feedwater Pump Recirculation valve closes.

ATTACHMENT 12
PAGE 2 OF 2

INSTRUCTIONS FOR SINGLE CONDENSATE PUMP OPERATION

3. • SOP-302A, Section 5.1.5 provides action necessary to alternate feedwater pumps at power. The additional limitations above apply since only one Condensate Pump is in operation.

4. The following considerations apply for starting the second Condensate Pump/Main Feedwater Pump:

   - Starting the second Condensate Pump at higher power levels may result in a more pronounced FWP suction pressure drop as the Condensate Pump discharge valve opens in preparation for pump start. The drop in FWP suction pressure is caused as flow from the running Condensate pump seats the discharge check valve of the pump being started. Experience has shown that starting a second Condensate Pump at 43% power could cause a momentary drop in FWP suction pressure of approximately 70 psig.

   - It may be desired to test the idle Condensate Pump's check valve for back-leakage prior to prior to starting the pump. Leakage through the discharge check could result in a lower feedwater pump suction pressure than normally experienced.

   - Start of the second Condensate Pump may result in an increase of total Condensate System flow, which could reduce the amount of Heater Drain flow being supplied to Main Feedwater Pumps. Main Feedwater Pump speed may gradually decrease as result of increased suction pressure supplied to the feedwater pump. The increase in condensate flow and reduction in heater drain flow may affect the balance of the secondary system (extraction steam pressure, heater drain levels, heater drain tank level, etc.) and cause an efficiency loss.

   - Maintaining Condensate System flow above the opening setpoint of the Condensate Pump Recirculation Valve (6000 gpm) will maintain the recirc valve closed so feedwater pump suction pressure is not affected.

   - Following startup of the second Condensate Pump, adequate Feedwater Pump suction pressure should be available to allow a normal startup of the second Main Feedwater Pump without a power reduction.

ATTACHMENT 13
PAGE 1 OF 2

Steps to Ready Unit for Turbine Load Increase Following Section 5.6 Power Reduction

This attachment provides steps to reconcile equipment alignment between the end of Section 5.6 and the beginning of Section 5.4. The actions of Section 5.6 may be performed to reduce Turbine and Reactor power to a power level of approximately 18% to support maintenance activities. Following completion of the activity which necessitates power to be reduced, it may be desired to re-enter Section 5.4 to increase Turbine and Reactor power. The steps on this attachment are those performed as part of the Section 5.6 power decrease, but are not part of the normal Section 5.4 power increase sequence. Ensuring equipment is aligned per the following steps confirms that equipment is aligned the same as if entry into Section 5.4 was from Section 5.3.

1. CONTACT Chemistry AND ENSURE the specified demineralizers are in service per SOP-103A or SOP-106A prior to starting the power increase.

   _______/_______
   Initials Date

2. IF FW Heaters 3A and 3B have been isolated due to waterhammer, THEN PERFORM the following:

   A. IF Extraction Steam Isolation valves to FW Heater 3A and 3B are caution tagged due to the drain valves being closed, THEN ENSURE caution tags are removed:

   ☐ • 1-HS-2031, FW HTR 3A ES SPLY VLV

   ☐ • 1-HS-2032, FW HTR 3B ES SPLY VLV

   _______/_______
   Initials Date

   B. IF valves are closed, THEN slowly OPEN FW Heater 3A and 3B drain valves:

   ☐ • 1HD-0049, HTR DRN SYS FW HTR 1-3A TO HTR DRN TK 2-3-2 ISOL VLV

   ☐ • 1HD-0114, HTR DRN SYS FW HTR 1-3B OUT TO HTR DRN TK 2-3-2 ISOL VLV

   _______/_______
   Initials Date

   C. OPEN the Extraction Steam Isolation valves to the heaters:

   ☐ • 1-HS-2031, FW HTR 3A ES SPLY VLV

   ☐ • 1-HS-2032, FW HTR 3B ES SPLY VLV

   _______/_______
   Initials Date

ATTACHMENT 13
PAGE 2 OF 2

Steps to Ready Unit for Turbine Load Increase Following Section 5.6 Power Reduction

3. IF Pressurizer vapor (steam) space aligned for a continuous purge to the VCT (1-MLB-1A2 Window 1.1, PRZR STM SMPL ISOL OPEN 1-HV-4165 - Light Lit),
THEN
PERFORM the following:

   A. NOTIFY Chemistry to secure purge per COP-101A. ________/________ Initials Date

   B. STOP RCS purge via the VCT to gas decay tanks per RWS-201. ________/________ Initials Date

4. ENSURE 6.9KV normal buses are supplied from Unit 1 Auxiliary Transformer 1UT OR TRANSFER the 6.9KV normal buses from the Station Service Transformer 1ST to 1UT per SOP-603A. ________/________ Initials Date

5. ENSURE BOTH HIGH FLUX AT SHUTDOWN block switches on the NIS Source Range Drawers in the NORMAL. ________/________ Initials Date

> NOTE: Control Banks shall be within the insertion, sequence and overlap limits specified in the COLR per TS 3.1.6.

6. GO TO Section 5.4. ________/________ Initials Date

COMMENTS:____

____

____

ATTACHMENT 14
PAGE 1 OF 2

Steam Dump Operation for Load Reject Testing

CAUTION: IF at any time during this test a Turbine Runback or Reactor Trip occurs, THEN PLACE Steam Dumps back in the Tave Mode.

NOTE: The T_{AVE} Deviation meter will be unreliable due to the Reactor power - Turbine power mismatch. T_{AVE} should be maintained using T_{AVE} meters and TDM-301A.

1. To set Steam Dumps up in Steam Pressure Mode and ready to actuate for a Load Reject, PERFORM the following:

☐ A. ENSURE 1-PK-507, STM DMP PRESS CTRL is in MANUAL and 0%.

☐ B. SWEEP pot on 1-PK-507, STM DMP PRESS CTRL to ensure proper operation.

☐ C. VERIFY 1-PCIP, 1.4, CNDSR AVAIL STM DMP ARMED C-9 is ON.

☐ D. ENSURE BOTH STM DMP INTLK SELECT switches are ON.

☐ E. PLACE 43/1-SD, STM DMP MODE SELECT in STM PRESS AND VERIFY steam dump valves stay closed.

NOTE: PWR OPS Screen on Plant Computer may be useful in tracking Main Steam Pressure.

☐ F. RECORD current pressure on 1-PI-507, MS HDR PRESS. _________

☐ G. ENSURE 1-PK-507, STM DMP PRESS CTRL pot set 30 psig above current pressure on 1-PI-507, MS HDR PRESS per TDM-501A.

☐ H. PLACE 1-PK-507, STM DMP PRESS CTRL in AUTO AND VERIFY steam dump valves stay closed.

☐ I. ADJUST 1-PK-507, STM DMP PRESS CTRL pot to current pressure on 1-PI-507, MS HDR PRESS per TDM-501A.

☐ J. PERFORM Turbine Load Reject per Test procedure OR this IPO.

NOTE: With the Steam Pressure at previous value before load reject, it should be at the proper T_{AVE} using T_{AVE} meters and TDM-301A.

☐ K. If necessary, ADJUST 1-PK-507, STM DMP PRESS CTRL pot to pressure recorded in Step F. on 1-PI-507, MS HDR PRESS.

ATTACHMENT 14
PAGE 2 OF 2

Steam Dump Operation for Load Reject Testing

> NOTE: The intention of the next step is to return Steam Dumps to the Tave Mode when not needed to support load reject testing and load has been restored. All the testing of the Digital Control System may not be complete when Steam Dumps are restored to Tave Mode.

2. When Load Reject Testing is complete and Turbine Load has been returned to pretest value, return Steam Dumps to Tave Mode by PERFORMING the following:

☐ A. VERIFY ALL Steam Dump valves are CLOSED.

☐ B. PLACE 1-PK-507, STM DMP PRESS CTRL in MANUAL AND REDUCE demand to 0%.

☐ C. VERIFY the 1-PCIP, 3.6, TAVE LO LO P-12 is OFF.

☐ D. PLACE 43/1-SD, STM DMP MODE SELECT to RESET THEN PLACE in TAVE.

☐ E. VERIFY 1-PCIP, 3.4, TURB LOAD REJ STM DMP ARMED C-7 is OFF.

☐ F. VERIFY ALL Steam Dump valves remain CLOSED.

☐ G. ENSURE 1-PK-507, STM DMP PRESS CTRL is set per TDM-501A.

COMMENTS: ______________________________

____

____

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Steam Trap Blowdown

OPEN the following trap bypass valves for approximately two minutes to clear the strainers AND then CLOSE the associated valve.

(East Side of the Main Condenser)		OPEN	CLOSE
• 1MS-0743,	MSL 1-03 AFT MSIV D\POT 1-01 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0744,	MSL 1-02 AFT MSIV D\POT 1-02 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0745,	MSL 1-04 AFT MSIV D\POT 1-03 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0746,	MSL 1-01 AFT MSIV D\POT 1-04 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0747,	MSL 1-03 TO MSR 1-A D\POT 1-05 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0748,	MSL 1-02 TO MSR 1-A D\POT 1-06 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0749,	MSL 1-01 TO MSR 1-B D\POT 1-07 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0750,	MSL 1-04 TO MSR 1-B D\POT 1-08 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0751,	MSL 1-04 STRN D\POT 1-09 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0752,	MSL 1-01 STRN D\POT 1-10 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0753,	MSL 1-02 STRN D\POT 1-11 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0754,	MSL 1-03 STRN D\POT 1-12 STM TRAP STRN BLDN VLV	☐	☐

ATTACHMENT 15
PAGE 2 OF 2

Steam Trap Blowdown

(South Side of the Main Condenser)		OPEN	CLOSE
• 1MS-0755,	STM DMP HDR D\POT 1-13 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0758,	STM DMP HDR D\POT 1-22 STM TRAP STRN BLDN VLV	☐	☐
• 1MS-0760,	STM DMP STM TRAP 1-18 STRN BLDN VLV	☐	☐
• 1MS-0761,	STM DMP STM TRAP 1-19 STRN BLDN VLV	☐	☐
• 1MS-0762,	STM DMP STM TRAP 1-20 STRN BLDN VLV	☐	☐
• 1MS-0763,	STM DMP STM TRAP 1-21 STRN BLDN VLV	☐	☐
• 1MS-0764,	STM DMP STM TRAP 1-22 STRN BLDN VLV	☐	☐
• 1MS-0765,	STM DMP STM TRAP 1-23 STRN BLDN VLV	☐	☐
• 1MS-0766,	STM DMP STM TRAP 1-24 STRN BLDN VLV	☐	☐
• 1MS-0767,	STM DMP STM TRAP 1-25 STRN BLDN VLV	☐	☐
• 1MS-0768,	STM DMP STM TRAP 1-26 STRN BLDN VLV	☐	☐
• 1MS-0769,	STM DMP STM TRAP 1-27 STRN BLDN VLV	☐	☐
• 1MS-0770,	STM DMP STM TRAP 1-28 STRN BLDN VLV	☐	☐
• 1MS-0771,	STM DMP STM TRAP 1-29 STRN BLDN VLV	☐	☐
(North of MFP 1-01)			
• 1MS-0757,	FWPT 1-A HP D\POT 1-20 STM TRAP STRN BLDN VLV	☐	☐
(North of MFP 1-02)			
• 1MS-0756,	FWPT 1-B HP D\POT 1-19 STM TRAP STRN BLDN VLV	☐	☐

COMMENTS: ____

____

Steam Trap Blowdown complete: ______________________ / __________
Signature DATE

ATTACHMENT 16
PAGE 1 OF 6

Extended Operation with Turbine at 1800 RPM for Testing

This attachment provides information related to the Turbine Generator operating at 1800 rpm for an extended time for testing. Time spent with the Main Turbine at 1800 RPM AND NOT synchronized to the grid should be minimized to prevent possible turbine damage.

CAUTIONS, LIMITATIONS and NOTES

- Performance of some Testing Procedures may require the turbine generator to remain at no-load conditions (1800 rpm) for an extended period of time.
- The limitations for the rate of change of reactor power specified in IPO-003A apply during performance of Testing.
- The Turbine Generator should be operated within the limits specified in TDM-401A.
- All Turbine Generator operating limits specified in IPO-003A are applicable during performance of any testing. The established actions to be taken if a Turbine Generator limit is exceeded remain valid and should be taken as necessary to address the off-normal condition.
    - Limit LP Turbine ΔT to prevent the bottom of the LP Turbine support arms from being hotter than the top by more than 50°F.
    - If ΔT reaches 60°F, actions should be initiated to restore temperature within 15 minutes.
    - When ΔT can not be reduced to <60°F within 15 minutes, the generator should be synchronized OR the turbine stop and control valves should be closed within the following 15 minutes.
- The preferred methods to maintain Reactor power and temperature prior to synchronization are use of Steam Dumps and SG Blowdown Flow. Steam Dump operation and Main Steam Line Drain flow affect LP Turbine casing ΔT, which should be monitored prior to synchronization.
- If LP Turbine casing ΔT approaches limits prior to synchronization, a reduction in Steam Dump operation may be required, and Main Steam Line drain flow should also be limited.
- The preferred method, to reduce Steam Dump Operation and Main Steam Line drain flow, is maintaining maximum SG Blowdown flow.

ATTACHMENT 16
PAGE 2 OF 6

Extended Operation with Turbine at 1800 RPM for Testing

INSTRUCTIONS

1. PERFORM LP Turbine monitoring until the generator is synchronized:

   A. LP Turbine Monitoring System temperatures are being monitored and trended on The Plant Computer (Group Displays LPTDIFF, LPT1CASE and LPT2CASE).

      _______/_______
      Initials Date

> NOTE: The LP Turbine Monitoring System thermocouples are installed at 50% of the support arm wall thickness. Operator initiated actions to reduce temperature will not be seen immediately. Vendor representatives may modify the following limits based on temperature trends during startup and operational performance.

   B. IF differential temperature approaches 50°F, THEN PERFORM the following actions as necessary to reduce temperature:

      - REDUCE steam dump operation. _______/_______ Initials Date

      - REDUCE Main Steam line drain flow to the condenser. _______/_______ Initials Date

      - ENSURE SG Blowdown flow is maximized. _______/_______ Initials Date

      - REDUCE Reactor power to approximately 2 - 3% per Step 2. _______/_______ Initials Date

> CAUTION: Exhaust hood spray valves should NOT be used as a method of differential temperature control when Turbine speed is less than rated speed (1800 rpm).

      - WHEN Turbine speed is approximately 1800 rpm, THEN CYCLE exhaust hood spray valves 1-HS-6556, EXH HOOD SPR VLV and 1-HS-6555, EXH HOOD SPR BYP VLV as necessary to control differential temperature. _______/_______ Initials Date

      - SYNCHRONIZE the generator per Section 5.1 as soon as possible. _______/_______ Initials Date

ATTACHMENT 16
PAGE 3 OF 6

Extended Operation with Turbine at 1800 RPM for Testing

1. C. IF differential temperature $\geq 60°F$, THEN PERFORM the following:

- RESTORE differential temperature <60°F within 15 minutes, ______/______ Initials Date

  OR

- Within the following 15 minutes, SYNCHRONIZE the generator per Section 5.1, ______/______ Initials Date

  OR

- CLOSE the turbine stop and control valves. ______/______ Initials Date

CAUTION:	Operating requirements for MODE 1 are being maintained during MODE 2 operation to allow a timely return to MODE 1 (i.e. to preclude the need to reperform MODE 1 entry signoffs for the return to MODE 1). If the impact review of operating conditions for MODE 1 is not performed throughout the entire period of MODE 2 operation, a re-verification of the MODE 1 entry checklist (Attachment 1) is required to be performed prior to entering MODE 1.

NOTE:	To minimize the consequences of Turbine heating during extended Steam Dump operation, Reactor power may be reduced to a level that will maintain Turbine speed and minimize Steam Dump operation. Reducing Reactor power will return the plant to MODE 2. When the Turbine is ready to be synchronized to the Grid, Reactor power will be raised back to 6% - 8% and MODE 1 will be re-entered.

2. IF it is necessary to reduce Reactor power to maintain Turbine Generator operating limits, THEN PERFORM the following:

   A. IF desired, THEN ENSURE the FW BYP CTRL controllers are in AUTO. ______/______ Initials Date

ATTACHMENT 16
PAGE 4 OF 6

Extended Operation with Turbine at 1800 RPM for Testing

> NOTE: This step is a continuous action step and should be conveyed to the oncoming crew to ensure all aspects of this step is throughly turned over to eliminate possible problems going back to Mode 1.

2. B. ENSURE the following conditions are maintained during MODE 2 operation:

- CONTINUE OPT-102A for MODE 1 surveillances AND INITIATE verification of MODE 2 requirements during OPT-102A performance.
- IMPACT any new TS, TRM and ODCM OPERABILITY assessments for maintenance activities or degraded conditions against MODE 1 AND MODE 2 LCOs.
- ENSURE the 50.59 screenings and evaluations of any new Temporary Modification is reviewed for MODE 1 AND MODE 2 impact.
- ENSURE any lock valve deviations that could affect Mode Change are tracked.
- ENSURE any new entered clearance, Annunciator/Instrument Out-of-Service entry, locked component deviation entry, standing order or shift order directives, system status file deviation entry and assessed SmartForm condition is impacted for MODE 1 AND MODE 2 operation.

________ / ________
Initials Date

C. Oncoming Unit Supervisor understands and has been informed of all above conditions.

________ / ________
Initials Date

D. As Reactor power decreases, VERIFY the Steam Dump system continues to maintain steam pressure at approximately 1092 psig.

________ / ________
Initials Date

E. **WHEN Reactor power is $\leq$5%, THEN LOG the time MODE 2 is entered:**

________ / ________ / ________
Initials Date Time

F. Slowly REDUCE Reactor power to approximately 2% - 3% while maintaining Turbine speed at approximately 1800 rpm.

________ / ________
Initials Date

G. Upon entry into Mode 2, COMMENCE Attachment 1, CHECKLIST SIGNOFF REQUIRED PRIOR TO ENTRY INTO MODE 1 Asterisk Steps only.

________ / ________
Initials Date

ATTACHMENT 16
PAGE 5 OF 6

Extended Operation with Turbine at 1800 RPM for Testing

3. WHEN Testing at 1800 rpm is complete AND it is desired to prepare the Turbine Generator for synchronization,
THEN
PERFORM the following:

A. IF desired,
THEN
ENSURE the FW BYP CTRL controllers are in AUTO.

_______/_______
Initials Date

B. ENSURE the following conditions are met to permit re-entry into MODE 1:

- Evaluation of MODE 1 operating requirements have been maintained per Step 2B.
IF the impact review of operating conditions for MODE 1 has not been maintained,
THEN
ENSURE Attachment 1 has been completed and reviewed by the Shift Manager.

_______/_______
Initials Date

- REVIEW ODA-308 to ensure there have been no new LCOARs entered that may affect entry into MODE 1.

_______/_______
Initials Date

- REVIEW Smart Forms for any Mode 1 Restraints.

_______/_______
Initials Date

- Attachment 1, CHECKLIST SIGNOFF REQUIRED PRIOR TO ENTRY INTO MODE 1 asterisk steps have been signed off for entry into MODE 1.

_______/_______
Initials Date

C. As Reactor power increases, VERIFY the Steam Dump system continues to maintain steam pressure at approximately 1092 psig.

_______/_______
Initials Date

D. **WHEN Reactor power is >5%,**
THEN
LOG the time MODE 1 is entered:

_______/_______/_______
Initials Date Time

ATTACHMENT 16
PAGE 6 OF 6

Extended Operation with Turbine at 1800 RPM for Testing

3. E. ENSURE OPT-102A is being performed for MODE 1 surveillances. ________/________ Initials Date

F. Slowly INCREASE Reactor power to approximately 6% - 8%. ________/________ Initials Date

NOTE: Extraction Steam Valves may go closed while in Mode 2 and Step 5.1.33 may need to be re-performed.

G. RETURN TO Step in effect. ________/________ Initials Date

COMMENTS: ____

____

____

____

Attachment Satisfactorily completed:________________________/________
SHIFT MANAGER DATE

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MODE 1 BUBBLE CHART

Instructions:

- The bubble chart includes steps of Sections 5.1 to 5.6 in the IPO.
- It is divided into five sections.

  Section 5.1 is diagramed throughout with pentagons.

  Section 5.2 is diagramed throughout with parallelograms.

  Section 5.3 is diagramed throughout with diamonds.

  Section 5.4 is diagramed throughout with hexagons.

  Section 5.6 is diagramed throughout with squares.

  Circled letters indicate transition to the next page.
- All steps found in parallel can be performed at the same time.
- Solid lines designate preferred method.
- Dark center line designates main procedure flowpath.
- A systematic step-by-step review and implementation of the procedure instructions (steps, notes and cautions) is required to implement this IPO. The chart provides guidance as to what sequence the IPO may be performed when in MODE 1 operation.
- IF this chart is used,
  THEN
  the IPO must still be signed off in its entirety.

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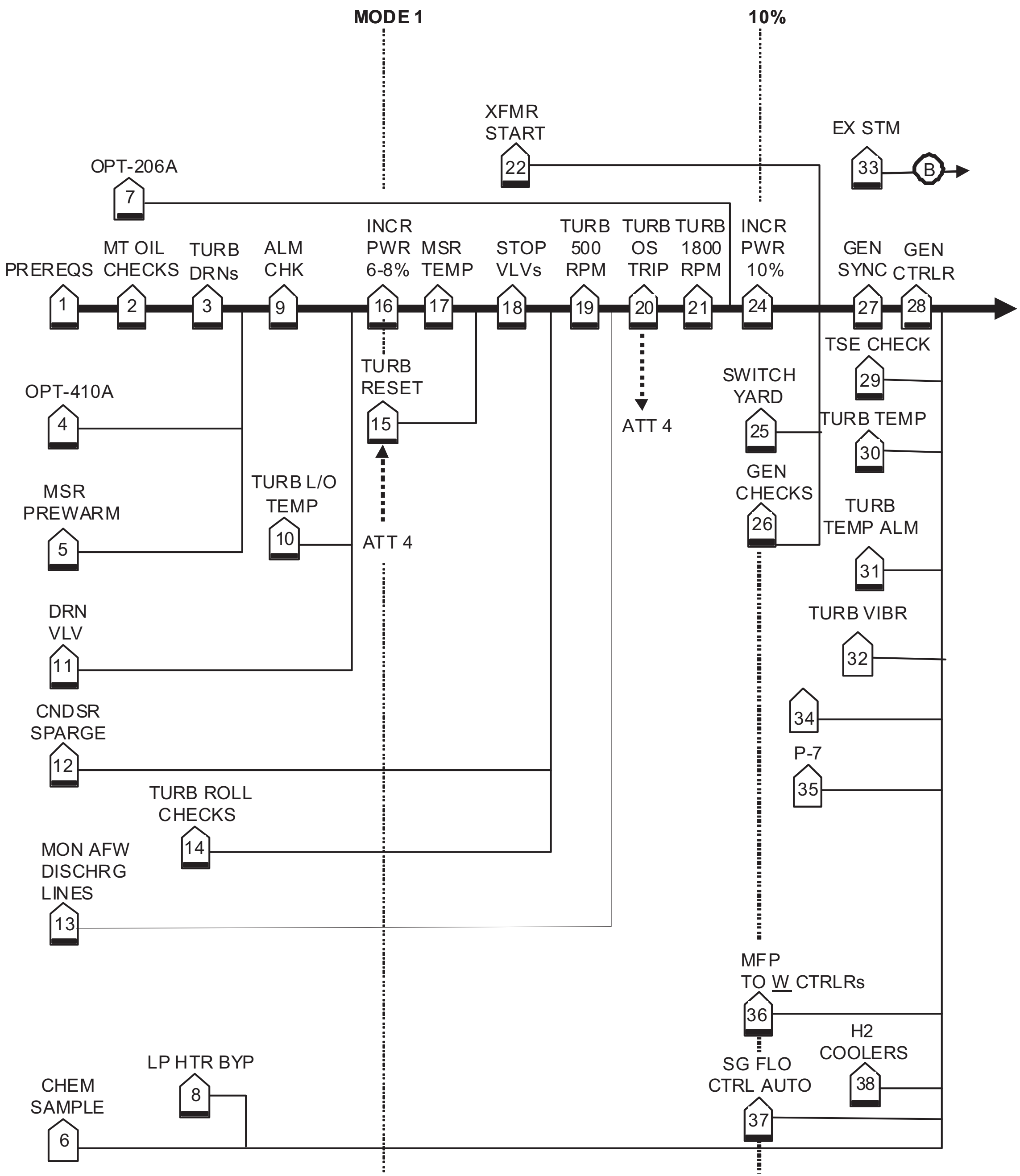
MODE 1 BUBBLE CHART

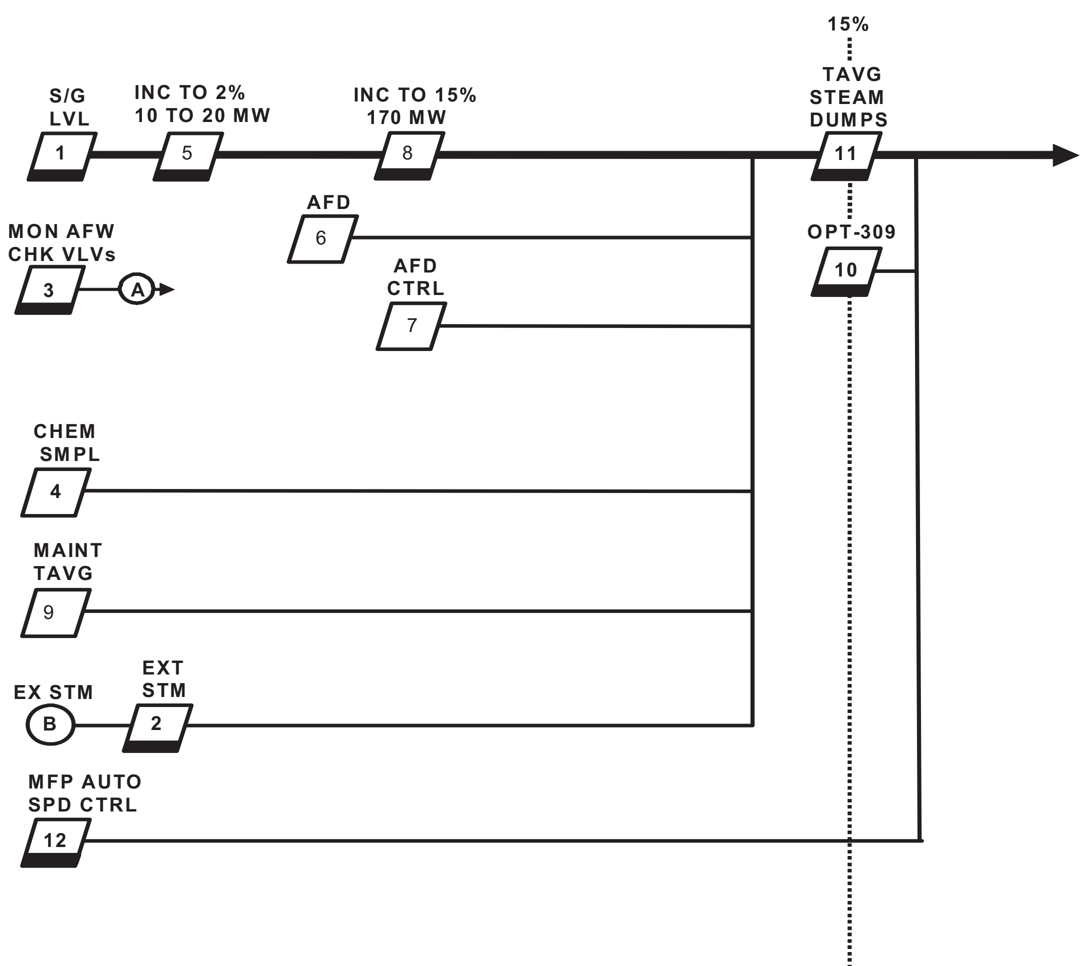
SECTION 5.1 Warmup And Synchronization of the Turbine Generator



PARTIALLY COLORED DIAGRAM REFERS TO SECONDARY ACTIONS

Attachment 17
PAGE 3 OF 6

SECTION 5.2 Establishing Turbine Load Control



PARTIALLY COLORED DIAGRAM REFERS TO SECONDARY ACTIONS

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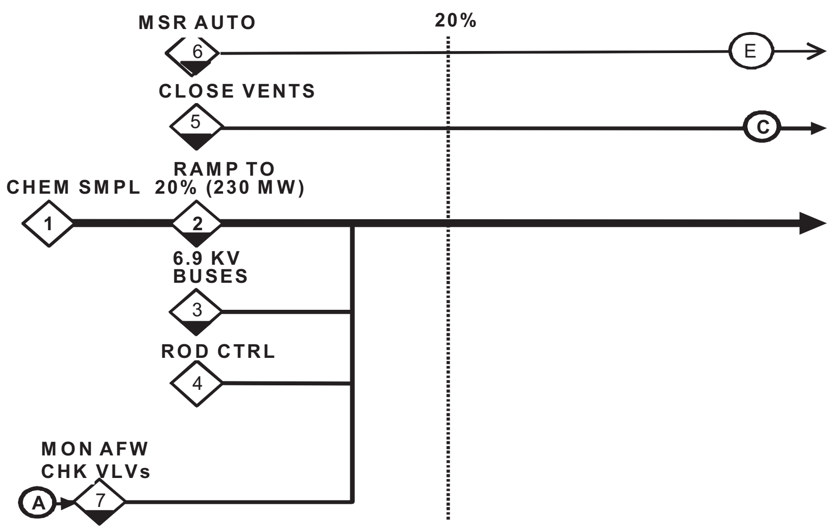
SECTION 5.3 Establishing 20% Turbine Load



SECTION 5.4 Establishing 100% Turbine Load

PARTIALLY COLORED DIAGRAM REFERS TO SECONDARY ACTIONS

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-003A
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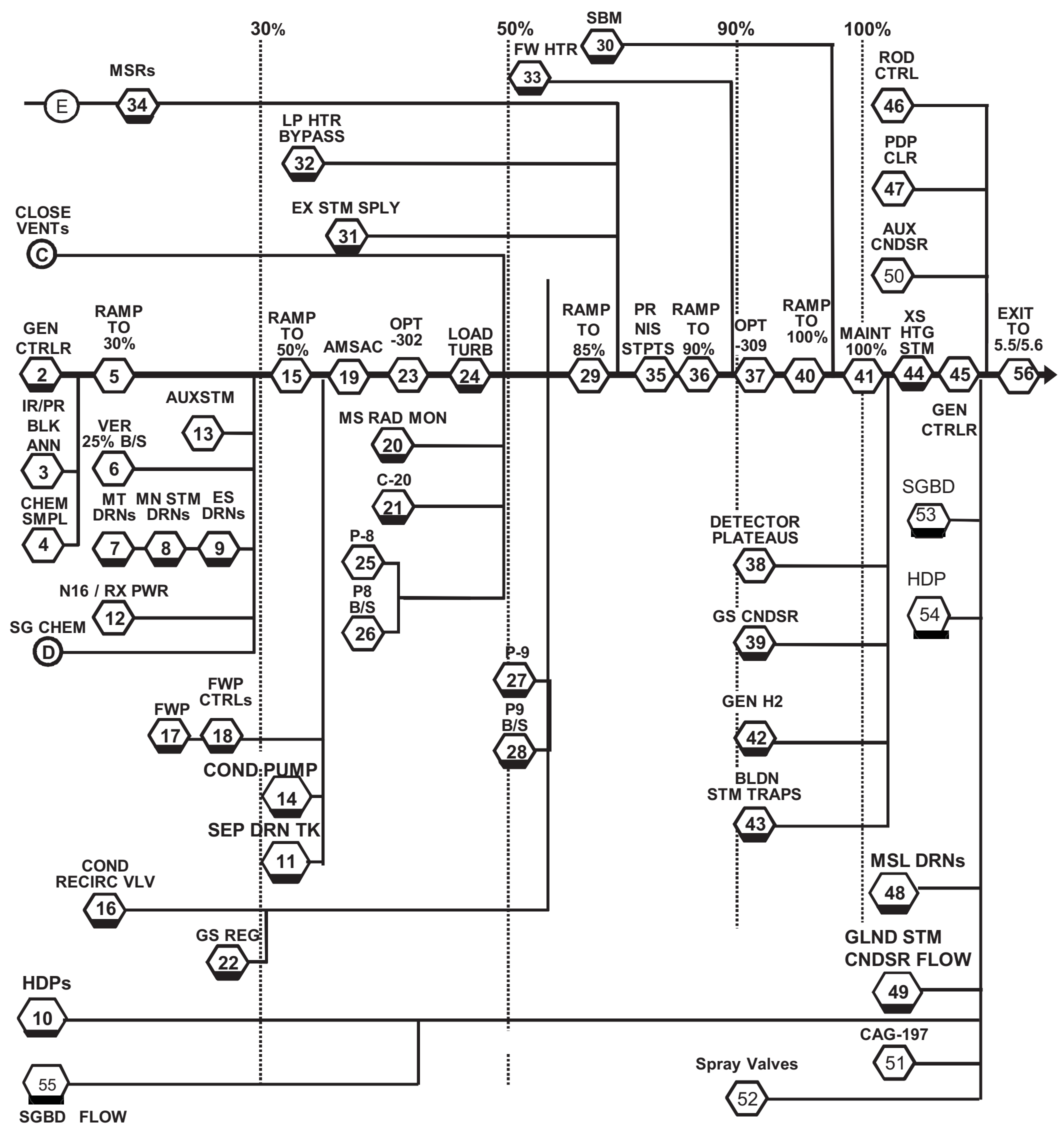
MODE 1 BUBBLE CHART

SECTION 5.4 Establishing 100% Turbine Load



PARTIALLY COLORED DIAGRAM REFERS TO SECONDARY ACTIONS

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-003A
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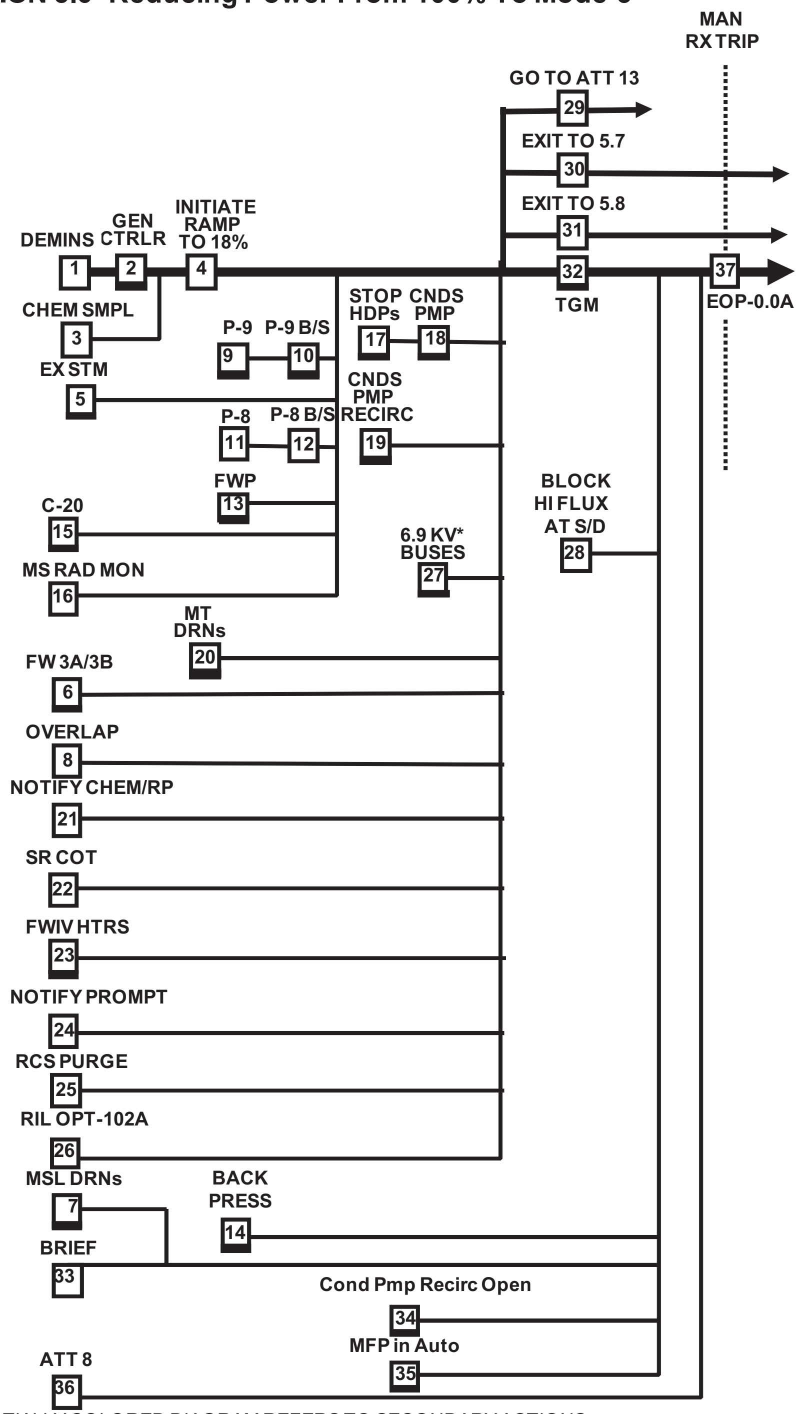
MODE 1 BUBBLE CHART

SECTION 5.6 Reducing Power From 100% To Mode 3



PARTIALLY COLORED DIAGRAM REFERS TO SECONDARY ACTIONS
* Step 27 maybe N/A if it will be performed in Section 5.8

ATTACHMENT 18
PAGE 1 OF 2

PRESSURIZER SPRAY BYPASS VALVE ADJUSTMENT

☐ 1. ENSURE Tcold is at normal operating temperatures.

☐ 2. ENSURE 1RC-8051 RC LOOP 1-01 TO PRZR 1-01 SPR VLV 0455B BYP VLV is positioned per TDM-901A.

☐ 3. ENSURE 1RC-8052 RC LOOP 1-04 TO PRZR 1-01 SPR VLV 0455C BYP VLV is positioned per TDM-901A.

☐ 4. ENSURE RCP 1-01 and RCP 1-04 are in operation.

☐ 5. ENSURE RC LOOP PRZR SPR VLV CTRL's are in MANUAL CLOSED.

- 1-PCV-0455B
- 1-PCV-0455C

☐ 6. WAIT for Loop 1 spray line temperature, 1-TE-0451 (T0483A), and Loop 4 spray line temperature, 1-TE-0452 (T0484A), to reach equilibrium. The temperature may be considered at equilibrium when there is less than 1 degree temperature change over 30 minutes.

NOTE: IF 1RC-8051 and 1RC-8052 did not need throttle repositioning per TDM-901A, the spray lines may be considered at equilibrium and this step may be skipped.

☐ 7. IF the spray line temperatures are between 530°-535°F as prescribed in TDM-901A, no adjustment to the throttle position is necessary.

☐ 8. IF the spray line temperature is outside the range specified in TDM-901A, TURN the valve 1/16th of a turn to raise or lower the spray line temperature towards the range of 530°-535°F.

- 1RC-8051
- 1RC-8052

☐ 9. WAIT for the spray line temperature to stabilize. The temperature may be considered stable when there is less than 1 degree temperature change over 10 minutes.

☐ 10. REPEAT steps to adjust spray line temperature UNTIL both loop spray line temperatures are between 530°-535°F.

☐ 11. WAIT 90 minutes to ensure the spray lines have reached temperature equilibrium.

ATTACHMENT 18
PAGE 2 OF 2

PRESSURIZER SPRAY BYPASS VALVE ADJUSTMENT

☐ 12. IF further valve repositioning is required, REPEAT steps to adjust spray line temperature.

☐ 13. Once spray line temperatures have reached equilibrium within 530°-535°F, RECORD the valve position and spray line temperature.

- 1RC-8051 position: _______________ turns from full closed
- 1-TE-0451 (T0483A): _______________ °F
- 1RC-8052 position: _______________ turns from full closed
- 1-TE-0452 (T0484A): _______________ °F

☐ 14. IF final valve position is not the same as specified in TDM-901A,
THEN
INITIATE a CR to update the TDM.

COMMENTS:____

____

____

ATTACHMENT 19
PAGE 1 OF 2

PRE-STAGING AME PUMP

The purpose of this attachment is to pre-stage the AME pump for use in the event an extended loss of AC power occurs while the Unit is in Mode 5 or Mode 6. The AME pump, hoses, and required connectors are pre-staged to expedite providing RCS makeup flow through the two-inch low pressure primary or secondary FLEX connections or makeup water to Steam Generators via AFW secondary FLEX connection. The specific flowpath to be used will depend on status of the RCS and Steam Generator availability when extended loss of AC power occurs.

☐ 1. INITIATE a Transient Combustible Permit.

☐ 2. PRE-STAGE AME pump near RWST valve room door.

3. PRE-STAGE the following items (Yard 810 inside Sea-Land #113 and AME pump storage building AME Tool Box #114) near AME pump:

Suction Hose

☐ • 6 - 6" X 10' long suction hose Female X Male Camlock (AME Pump Building)

Pump Suction Connections (Tool Box #114)

☐ • 1 - 4" FNPT X 6" Male Camlock Adapter
☐ • 1 - 5” STORZ X 6” Female Camlock Adapter
☐ • 1 - 5” STORZ X 4” MNPT Adapter

Pump Discharge Connection (Tool Box #114)

☐ • 1 - 5" STORZ X 2-1/2" FNH Adapter

Discharge Hose (Sealand #113)

☐ • 10 - 5" X 50' long blue hose with STORZ connections

Discharge to RCS via 2" Low Pressure Primary or Secondary Connection (Tool Box #114)

☐ • 1 - 5" STORZ X 2" FNPT Adapter
☐ • 1 - 2” NPT Street Elbow

ATTACHMENT 19
PAGE 2 OF 2

PRE-STAGING AME PUMP

3. Discharge to SGs via secondary AFW connection (Tool Box #114)

☐ • 3 - 5" STORZ X 4" FNPT Adapters

NOTE:	RWST security barriers should be removed to permit expedited access to the RWST FLEX suction valve whenever fuel is in the vessel and the RCS is depressurized < 100 psig.

☐ 4. COORDINATE with Security and Radiation Protection AND REMOVE RWST valve room security barrier access covers PM 351076.

Reactivity Briefing Sheet for Stable Operation

MOL PROJECTIONS - SIMULATOR USE ONLY

Valid for approximately 7 days.

Calculations based on core design values, and assume:

Burnup =	**12000.0**	MWD/MTU
	270.8	EFPD
Power =	**100**	RTP
Boron =	**775**	ppm
B10 Conc =	**0.183400**	w/o
Control Bank D =	**215**	steps

Burnup in the MOL range

NOTE: Re-create the Briefing Sheet if current values significantly differ from assumed inputs.

Reactivity affects of Control Bank D

HFP Diff Worth @ 215.0 steps = **-1.6** pcm / step

HFP Integral Rod Worth for CBD Step Positions:

Steps	pcm	Steps	pcm	Steps	pcm	Steps	pcm
225	0.0	218	-5.7	211	-17.7	200	-48.5
224	0.0	217	-7.0	210	-20.0	195	-65.6
223	-1.4	216	-8.4	209	-22.3	190	-83.6
222	-2.0	215	-10.0	208	-24.9	185	-102.0
221	-2.7	214	-11.7	207	-27.5	180	-120.4
220	-3.6	213	-13.6	206	-30.3	175	-138.7
219	-4.6	212	-15.6	205	-33.1	170	-156.7

Reactivity affects of Boron (Assuming BAT concentration of 7447.0 ppm)

HFP Diff Boron Worth @ 775 ppm = **-7.8** pcm / ppm

1-FK-110 Pot Setting for Blended Flow @ 775 ppm = **2.34** (90 gpm Total Flow)

1-FK-110 Pot Setting for Blended Flow @ 775 ppm = **3.30** (127 gpm Total Flow)

Reactivity affects of Power

Power Coefficient of Reactivity = **-16.0** pcm / % RTP

Dilution to equal 1% Power Increase = **180.5** gallons RMUW

Boration to equal 1% Power Decrease = **20.1** gallons boric acid

Reactivity affects of RCS Temperature

Temperature Coefficient of Reactivity (ITC) = **-21.5** pcm / ☜F

Boration to equal 1☜F Temperature Decrease = **27.1** gallons boric acid

Dilution to equal 1☜F Temperature Increase = **243.0** gallons RMUW

Load Reduction equal to 1☜F T_{ave} Increase = **16.0** MWe

Load Reduction Calculation Worksheet

Note: Do not perform these calculations following a Runback. For a Runback, borate per the Reactivity Briefing Sheets as soon as possible.

This computer generated form may be substituted for Attachment 1 of NUC-117 Rev 8

Contact Core Performance (817-432-0134) if possible to discuss the plan.

Unit ______ **Date / Time:** ____________________

A.1 Boration Volume ______________ **gallons**

Indicate source (listed in order of preference)

___ BEACON by Core Performance (obtain if time permits)
___ Reactivity Briefing Sheets from the Boration Matrix
___ CHORE output (under 'Tools' ->'Power Change Rx Calc IPO-003 ATT 3')
___ IPO-003A Attachment 3 Manual Calculation

A.2 Current Turbine Load Setpoint . . . . ______________ **MWe**

A.3 Final Turbine Load Setpoint . . . . ______________ **MWe**

(200 MWE if plant shutdown planned)

A.4 Total Turbine Ramp Time . . . . ______________ **minutes**

(Do not include calculation prep and Pre-Job Brief times)

Calculations:

B.1 Load Change . . . . ______________ **MWe**

= A.2 - A.3

B.2 Load Rate . . . . ______________ **MWe/min**

= B.1 / A.4

B.3 Total Boration Time . . . . ______________ **minutes**

Ideally, start time should be 5 minutes BEFORE load change is initiated.

If time does not allow, start time should be same as the load change start time.

Ideally, end time should be 15 minutes BEFORE load change is complete.

B.4 Boration Rate . . . . ______________ **gpm**

= A.1 / B.3

B.5 1-FK-110 Pot Setting . . . . ______________ **turns**

= B.4 / 4 (N/A for Batch Boration)

Reactivity Briefing Sheet for Runback to 900 MWe

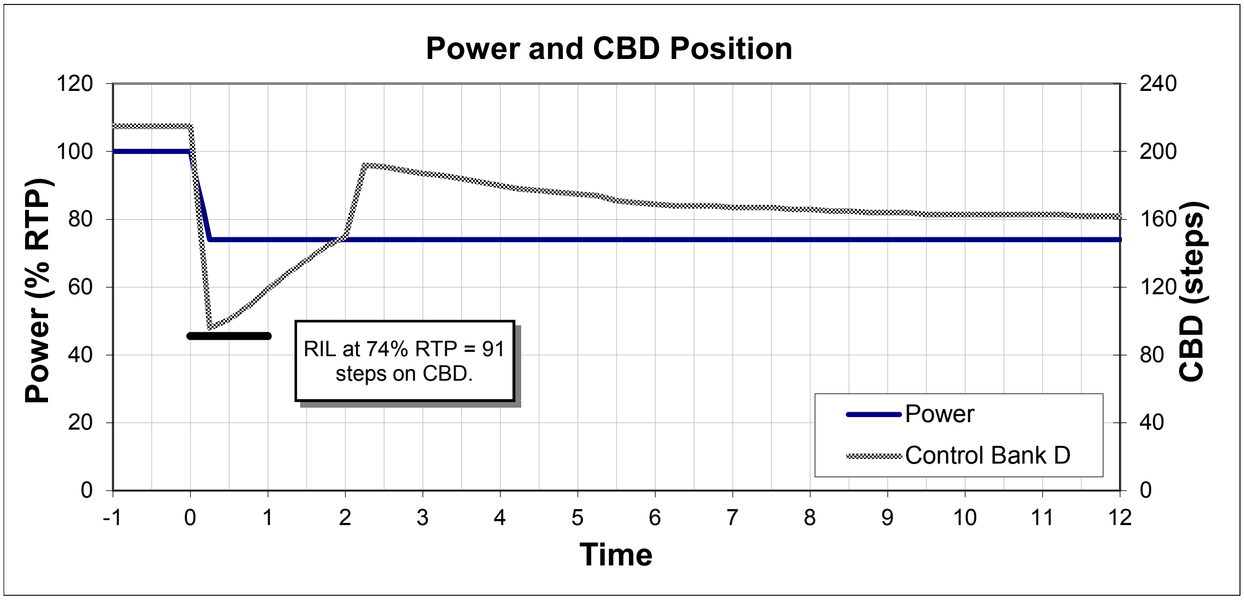
MOL PROJECTIONS - SIMULATOR USE ONLY

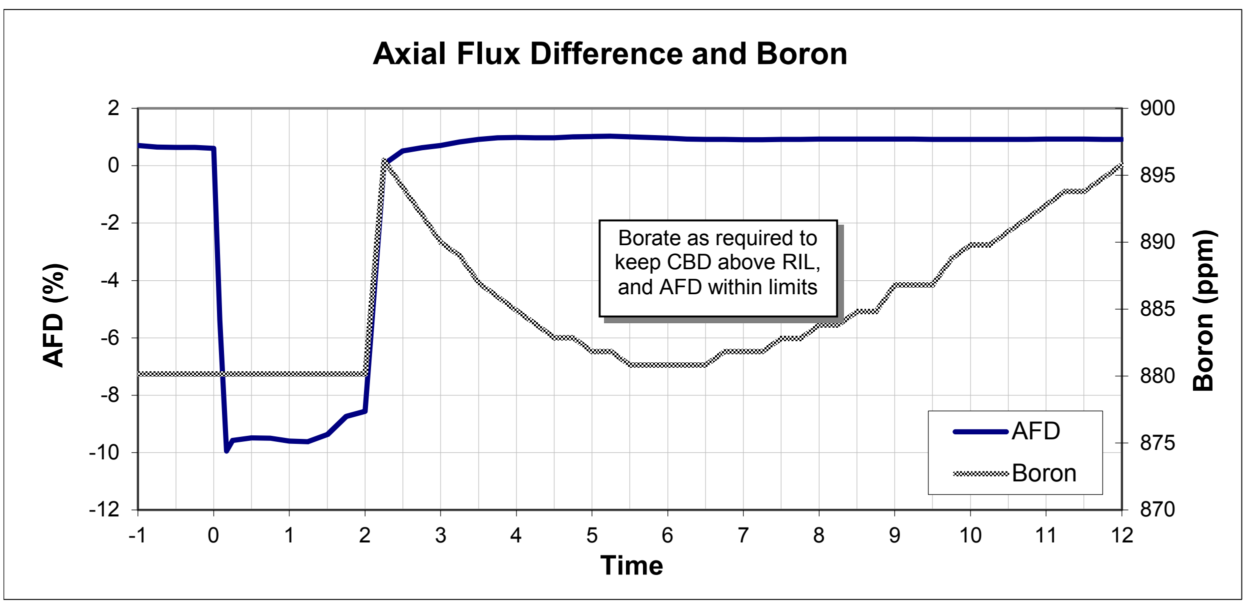
Basic Control Strategy:

A) A boration of 155 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 1200 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Runback to 800 MWe

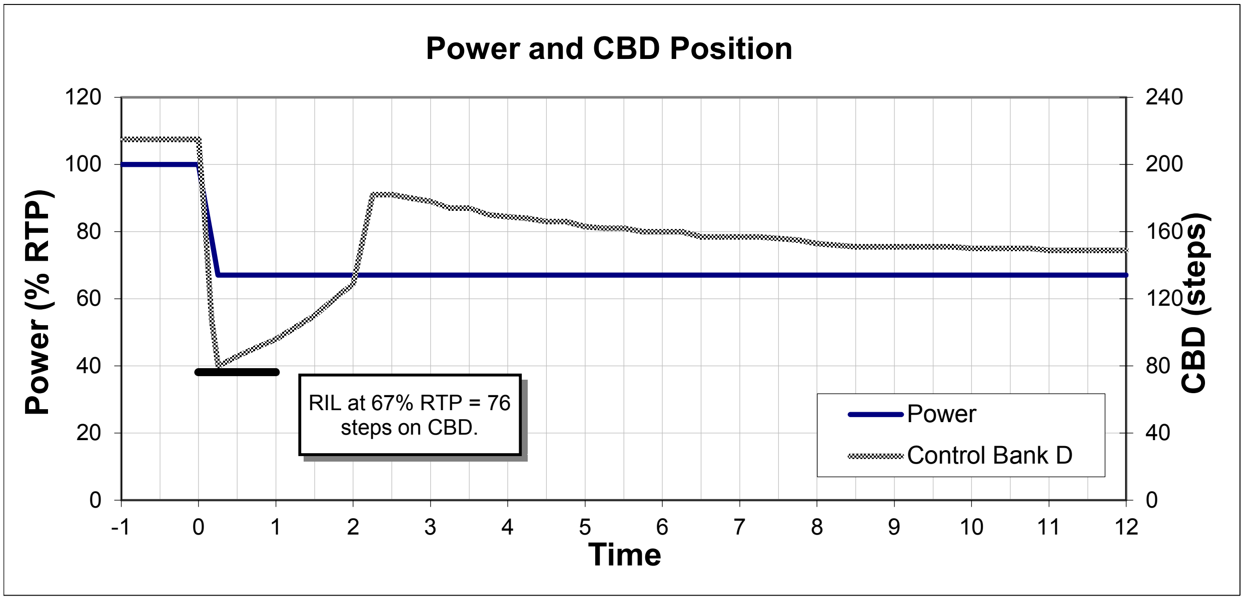
MOL PROJECTIONS - SIMULATOR USE ONLY

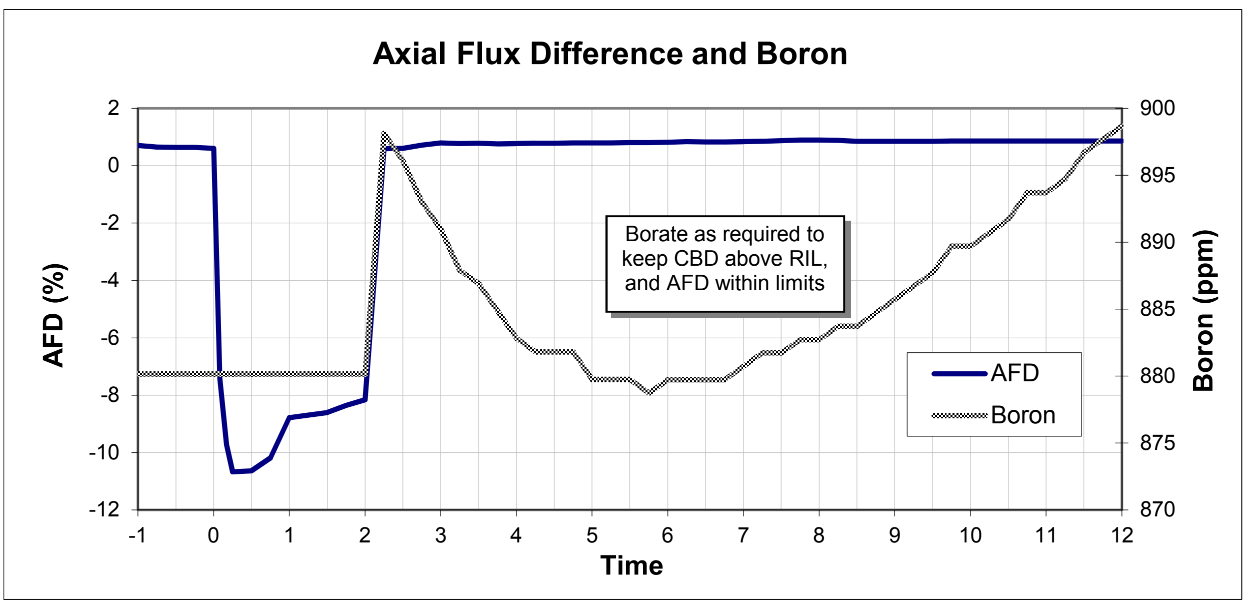
Basic Control Strategy:

A) A boration of 175 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 1500 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Runback to 700 MWe

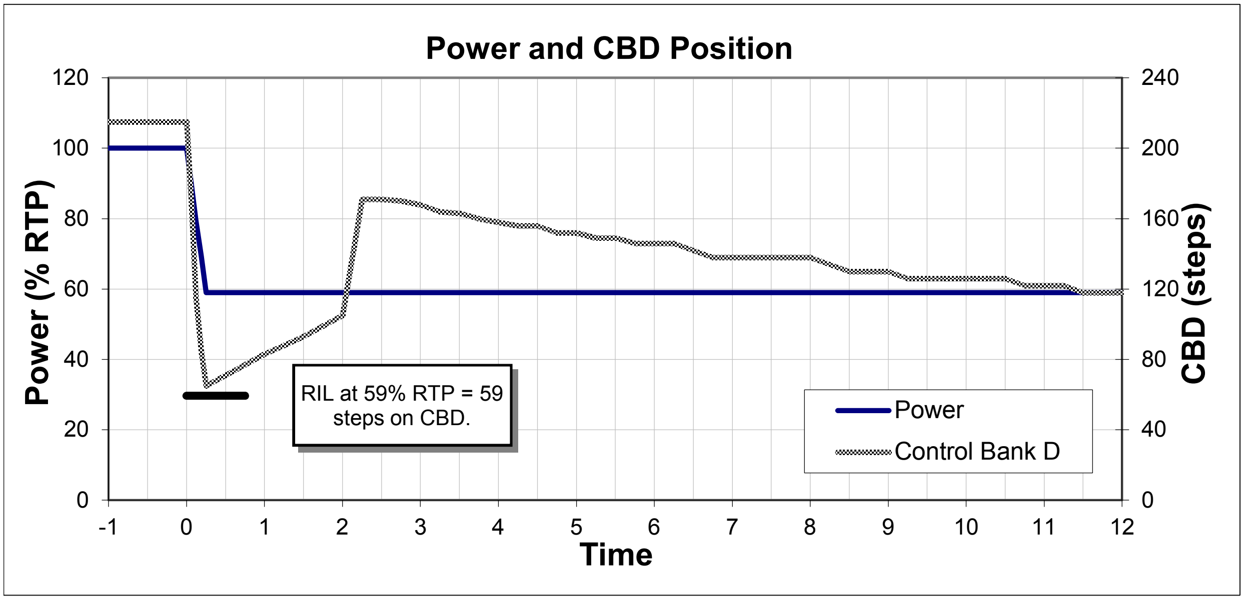
MOL PROJECTIONS - SIMULATOR USE ONLY

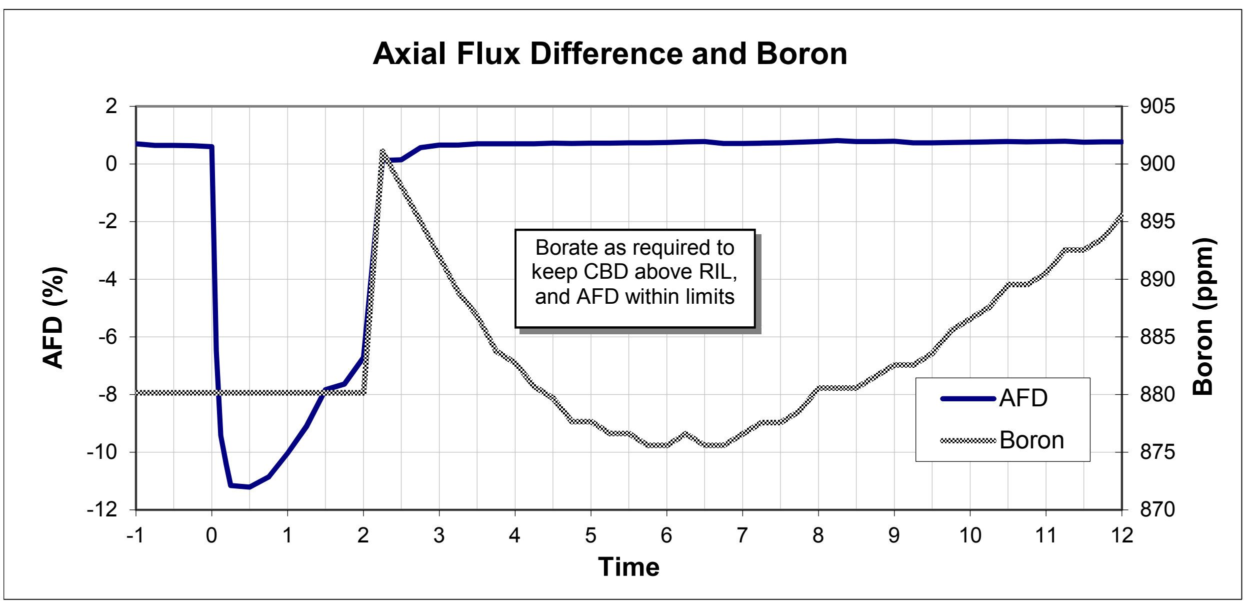
Basic Control Strategy:

A) A boration of 200 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 2000 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Downpower Boration Matrix

MOL PROJECTIONS - SIMULATOR USE ONLY

The boration/dilution estimates are based on BEACON predictions for maintaining Incore Axial Offset.

With deep rod insertion, it is expected AFD indications (based on Excore Detectors) will be less than the Incore value by ~2-4%. In this case, no immediate action is needed to restore AFD, but contact Core Performance.

Borate at a rate sufficient to allow ~15 minutes of mixing before the final power level is reached.

Contact Core Performance as soon as possible when planning ANY downpower for additional support.

Assumed Initial Conditions

Power	100	% RTP
CBD Position	215	steps
RCS Boron	864	ppm *(anticipated boron at middle of validity range)*

30 Minute Ramp Down Boration Estimates

	900 MWe	800 MWe	700 MWe	50% RTP
	(~74% RTP)	(~67% RTP)	(~59% RTP)	
Final CBD Position	*172 steps*	*161 steps*	*148 steps*	*123 steps*
Total Boration	*304 gal*	*384 gal*	*481 gal*	*561 gal*

Dilution in first hour to support maintaining reduced power, while holding Incore AFD on Target:

Followup Dilution (1st hour)	*1102 gal*	*1409 gal*	*1792 gal*	*2435 gal*
Ave Dilution Rate (1st hour)	*18.4 gpm*	*23.5 gpm*	*29.9 gpm*	*40.6 gpm*

Notes: Highlighted values: Max boration rate during downpower may be unable to maintain Target AFD. Restore and hold Target AFD as soon as possible following the Downpower.

2 Hour Ramp Down Boration Estimates

	900 MWe	800 MWe	700 MWe	50% RTP
	(~74% RTP)	(~67% RTP)	(~59% RTP)	
Final CBD Position	*172 steps*	*158 steps*	*142 steps*	*101 steps*
Total Boration	*191 gal*	*232 gal*	*286 gal*	*258 gal*

Dilution in first hour to support maintaining reduced power, while holding Incore AFD on Target:

Followup Dilution (1st hour)	*771 gal*	*1017 gal*	*1292 gal*	*1641 gal*
Ave Dilution Rate (1st hour)	*12.9 gpm*	*17 gpm*	*21.5 gpm*	*27.4 gpm*

1 Hour Rapid Shutdown (Ramp to 20% on Target AFD, 30 minute hold, trip)

	20% RTP
Final CBD Position	*79.2 steps*
Total Boration	*698 gal*

Notes:

After 30 minutes, no dilution (withdrawing rods to control power), holding at 20% RTP

CBD Position	*107.4 steps*	Incore AFD	*2.8 %*

UNIT SUPERVISOR RELIEF CHECKLIST

UNIT 1

OFF-GOING US: Unit Supervisor **SHIFT:** Night **DATE:** Today

ON-COMING US: ____________ **SHIFT:** ____________

PART I TO BE PREPARED BY THE OFF-GOING UNIT SUPERVISOR.

1.0 SHIFT ACTIVITIES:

1.1 **Activities Completed This Shift:**

OPT-112A Post Accident Monitoring

1.2 **Activities In-progress:**

MD AFW Pump 1-02 motor oil change

1.3 **Planned Activities:**

OPT-206 A when MDAFW work completes

2.0 PLANT AND EQUIPMENT STATUS:

2.1 **Technical Specification or Related Equipment Summary**

A1-17-0065 ->TS 3.7.5 AFW Condition B.1 - 72 hours for MDAFW 1-02 motor oil change (expected completion in 8 hours)

GEM on 1-HS-2450A

UNIT SUPERVISOR RELIEF CHECKLIST

2.2 **Non-Technical Specification Related Equipment Summary**

No equipment out of service.

3.0 GENERAL INFORMATION:

None

4.0 END OF SHIFT REVIEW:

LOGS – RO/BOP X LOGS-NEO X CLOSED eLCOARs ARCHIVED X
OPTS COMPLETD X DAILY ACTIVITIES LIST X LCOARs REVIEWED X
COMP ACTIONS REVIEWED X

PART II TO BE COMPLETED BY THE ON-COMING UNIT SUPERVISOR.

1.0 **CRITICAL PARAMETERS:**

MODE: 1 REACTOR POWER: 100 MWe: 1265
RCS TAVE: 585 °F CONTROL ROD POSITION 215 ON BANK D
C_B: 771 ppm RCS PRESS: 2235 psig

2.0 **STATUS REVIEW:**

	X	UNIT LOGS
[C]	X	* * LCOAR AND SYSTEMS IMPORTANT TO SAFETY STATUS [26082, 23486]
	X	UNIT DIFFERENCES (If last watch was on opposite unit)
	X	SHIFT ORDERS
	X	BOARD WALKDOWN
	X	* POD
[C]	X	CONDITIONAL SURVEILLANCE STATUS BOARD [23486]
	X	LOCATION OF SAFEGUARDS INFORMATION
	X	* RISK PROFILE FOR SHIFT

PROTECTED TRAIN [X] Train "A" [ ] Train "B"

* May be completed after turnover.
* * Each US's (U1 & U2) status review is to include the U1 & Common LCOAR & SIS Logs for Common equipment.

SHIFT RELIEF: ______________________ / ______________ / ______________
ON-COMING US SIGNATURE DATE TIME

Unit Supervisor
OFF-GOING US SIGNATURE

ON-COMING FSS REVIEW

SHIFT MANAGER REVIEW

Facility: CPNPP 1 & 2	Scenario No.: 2	Op Test No.: June 2017 NRC	
Examiners:		Operators:	

Initial Conditions: 100% power MOL – RCS Boron is 771 ppm (by sample). MDAFWP 1-02 is out of service for scheduled maintenance.

Turnover: Maintain steady-state power conditions. Severe weather has been reported in the area. The Station has entered ABN-907, Acts of Nature. Pressurizer Steam Space Sample is in progress by Chemistry.

Critical Tasks:

CT-1 - Isolate Reactor Coolant System Leakage Paths in accordance with ECA-0.0A, Loss of All AC Power prior to exiting ECA-0.0A.

CT-2 - Restore Power to Bus 1EA1 in accordance with ECA-0.0A, Loss of All AC Power, prior to exit from ECA-0.0A.

CT-3 - Manually start RHR Pump 1-01 in accordance with EOP-0.0A, Attachment 2 or EOP-1.0A, Attachment 1A prior to exiting EOP-1.0A, Loss of Reactor or Secondary Coolant.

Event No.	Malf. No.	Event Type*	Event Description
1	ED07A	C (RO, BOP, SRO) TS (SRO)	Loss of Inverter (IV1PC1)
2	SW01B	C (BOP, SRO) TS (SRO)	SSW Pump 1-02 trips
3	CV16A	I (RO, SRO)	VCT Level Channel LT-112 Fails Low
4	FW14B TC09I RD15A	R (RO) C (BOP, SRO) TS (SRO)	Heater Drain Pump 1-02 Trip Automatic Turbine Runback Failure Rods fail to control in automatic
5	ED01	M (RO, BOP, SRO)	Loss of All AC Power Due to Loss of Offsite Power
6	EG15A	C (BOP, SRO)	Emergency Diesel Generator 1-01 fails to start Emergency Diesel Generator 1-02 in pull-out due to SSW pump trip
7	OVRD	C (RO, SRO)	Pressurizer Steam Space Sample Valves (1/1-4165A & 1/1-4176A) fail to auto close. Manual closure required.
8	RC08A2	M (RO, BOP, SRO)	LBLOCA occurs when DG 1-01 is Emergency Started
9	RH01C	C (BOP)	RHR Pump 1-01 fails to auto-start from sequencer

* (N)ormal, (R)eactivity, (I)nstrument, (C)omponent, (M)ajor, (TS)Technical Specifications

Actual	Target Quantitative Attributes
9	Total malfunctions (5-8)
4	Malfunctions after EOP entry (1-2)
4	Abnormal events (2-4)
2	Major transients (1-2)
2	EOPs entered/requiring substantive actions (1-2)
1	EOP contingencies requiring substantive actions (0-2)
3	Critical tasks (2-3)

SCENARIO 2 SUMMARY

The crew will assume the watch at 100% power with no scheduled activities per IPO-003A, Power Operations. Severe weather has been reported in the area. MDAFWP 1-02 is tagged out for scheduled maintenance. A Pressurizer Steam Space sample is in progress.

Event 1
The first event is a loss of Inverter IV1PC1, crew actions are in accordance with ABN-603, Loss of a Protection or Instrument Bus, and include stabilizing the plant, restoring an alternate power source, and verification of instrument restoration. The SRO will refer to Technical Specifications and determine that TS 3.8.9 is applicable during the loss and exited upon power restoration.

Event 2
The next event is a trip of Station Service Water Pump 1-02. The crew will enter ABN-501, Section 2.0, Station Service Water Pump Trip. Various equipment controls, as directed by ABN-501, are placed in PULL OUT to prevent starting with no cooling water available. The SRO will refer to Technical Specifications.

Event 3
VCT level channel LT-112 will fail low. This will result in an automatic makeup. The RO will respond in accordance with the ALM and stop the auto makeup. The crew will refer to ABN-105, Chemical and Volume Control System Malfunction to place the makeup system into manual alignment until automatic control is restored.

Event 4
The next event is a trip of a Heater Drain Pump with an automatic turbine runback failure. The crew responds per ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section, 4.0. When it is determined that automatic plant response has not activated, control rods are placed/verified in auto and a manual Turbine Runback will be initiated. The control rods will fail to operate in auto, and must be manually controlled by the RO. The crew will stabilize load at 700 MWe. During this event, control rod position may drop below the Rod Insertion Limit (RIL) and when informed, the SRO will refer to Technical Specifications.

Events 5, 6, 7
The major event is a Loss of Offsite Power with a failure of Diesel Generator 1-01 to automatically start. Operators will perform an emergency start of DG 1-01 in accordance with ECA-0.0A, Loss of All AC Power. The event is complicated by the Pressurizer Steam Space Sample in progress and the valves must be manually closed.

Event 8
A LBLOCA will occur (delayed by 120 seconds) when DG 1-01 is emergency started. RHR Pump1-01 fails to auto-start from the SI sequencer; it is a critical task to manually start the only available RHR Pump. Entries into both FRP-0.1A, Response to Imminent Pressurized Thermal Shock Condition and FRZ-0.1, Response to High Containment Pressure, will be required; however the actions of this procedure will not be substantive.

Termination Criteria
This scenario is terminated when operators have performed the actions of EOP-1.0, Loss of Reactor or Secondary Coolant, and transition to EOS-1.3 A, Transfer to Cold Leg Recirculation is required or at the Lead Examiners' discretion.

Risk Significance:

• Failure of risk important system prior to trip:	Loss of Inverter IV1PC1 Loss of SSWP 1-02 / DG 1-02 Turbine Runback Failure
• Risk significant core damage sequence:	LOCA Failure of RHR Pump 1-01
• Risk significant operator actions:	Isolate RCS Leakage Paths Restore Safeguards Bus Manual Start of RHR Pump 1-01

Critical Task Determination

Critical Task	Safety Significance	Cueing	Measurable Performance Indicators	Performance Feedback
Isolate Reactor Coolant System Leakage Paths in accordance with ECA-0.0A, Loss of All AC Power prior to exiting ECA-0.0A.	Take one or more actions that would prevent a challenge to plant safety.	Procedural direction at ECA-0.0A Step 3 to minimize RCS inventory loss. Valve position indication and letdown flow.	The operator will manually close the Letdown Isolation Valves and Primary Sample Isolation Valves.	Valve position will change and letdown flow will lower to zero. MLB indication for closed valve position.
Restore Power to Bus 1EA1 in accordance with ECA-0.0A, Loss of All AC Power, prior to exit from ECA-0.0A.	Recognize a failure or an incorrect automatic actuation of an ESF system or component resulting in degraded ECCS capacity.	Procedural direction at ECA-0.0A Step 5 to restore power via EDG 1-01 to Safeguard Bus 1EA1. Bus voltage indication and EDG parameters.	The operator will manually perform an emergency start on EDG 1-01 using the handswitch on CB-11.	Indication of DG running and loading via bus voltage and frequency.
Manually Start RHR Pump 1-01 in accordance with EOP-0.0A Attachment 2 or EOP-1.0A, Attachment 1A prior to exiting EOP-1.0A, Loss of Reactor or Secondary Coolant.	Recognize a failure or an incorrect automatic actuation of an ESF system or component.	Procedural direction in EOP-0.0A, Attachment 2 to verify RHR Pumps running. Also procedural direction in EOP-1.0A, Attachment 1A to manually start ECCS pumps as necessary to maintain PRZR level. RHR Pump 1-02 in this case has no power, therefore RHR Pump 1-01 must be manually started to provide makeup flow to the RCS as this is a LBLOCA and RHR flow is required.	The operator will start RHR Pump 1-01 using handswitch 1/1-APRH1, RHRP 1 on CB-04.	Indication of pump start including light indication, flow and discharge pressure on CB-04.

	SIMULATOR OPERATOR INSTRUCTIONS for SIMULATOR SETUP				
INITIALIZE to IC-18 and LOAD NRC Scenario 2.					
EVENT	**TYPE**	**MALF #**	**DESCRIPTION**	**DEMAND VALUE**	**INITIATING PARAMETER**
SETUP	IRF	FWR021	MDAFWP 1-02 Breaker Racked Out	f:0	K0
4	IMF	TC09I	Automatic Turbine Runback Failure	f:1	K0
6	IMF	EG15A	DG 1-01 Fails to Auto Start	f:1	K0
7	IOR	LOANMLB 1A2_1	PSS Valve MLB Light 1-4165A	f:1	K0
	IOR	LOANMLB 1B2_1	PSS Valve MLB Light 1-4167A	f:1	K0
9	IMF	RH01C	RHR Pump 1-01 fails to start on sequencer	f:1	K0
1	IMF	ED07A	Loss of Inverter (IV1PC1)	f:1	K1
1	IRF	EDR01	Transfer 1PC1 to alternate power	f:0	K10
2	IMF	SW01B	Loss of SSW Pump 1-02	f:1	K2
3	IMF	CV16A	VCT Level Channel LT-112 Fails Low	f:0	K3
4	IMF	FW14B	Heater Drain Pump 1-02 Trip	f:1	K4
4	IMF	RD15A	Rods fail to move in Auto	f:1	K4
4	IMF	TC09I	Automatic Turbine Runback Failure	f:1	K0
5	IMF	ED01	Loss of Offsite Power	f:1	K5
6	IMF	EG15A	Diesel Generator 1-01 Fails to Auto Start	f:1	K0
7	IMF	OVRD	PRZR Steam Space Sample Valves (1/1-4165A & 1/1-4176A) Failure	f:1	K0
8	IMF	RC08A2	LBLOCA linked to DG Emergency Start {DIEG1DG1E.Value=4}	f:1	+120
9	IMF	RH01C	RHR Pump 1-01 fails to start on sequencer	f:1	K0

Simulator Operator:	**INITIALIZE to IC-18 and LOAD NRC Scenario 2.** **ENSURE all Simulator Annunciator Alarms are ACTIVE.** **ENSURE RED Danger Tag on MDAFWP 1-02 and place in PULL-OUT.** **ENSURE GEM Box PLACED on 1-HS-2450A for MDAFWP 1-01.** **ENSURE all Control Board Tags are removed.** **ENSURE Operator Aid Tags reflect current boron conditions (771 ppm).** **ENSURE Rod Bank Update (RBU) is performed.** **ENSURE Turbine Load Rate set at 10 MWe/minute.** **ENSURE 60/90 buttons DEPRESSED on ASD.** **ENSURE ASD speakers are ON to half volume.** **ENSURE Reactivity Briefing Sheet printout provided with Turnover.** **ENSURE procedures in progress are on SRO desk:** **- COPY of IPO-003A, Power Operations, Section 5.5, Operating at Constant Turbine Load.** **ENSURE Control Rods are in AUTO with Bank D at 215 steps.**

Control Room Annunciators in Alarm:

PCIP-1.1 – SR TRN A RX TRIP BLK
PCIP-1.2 – IR TRN A RX TRIP BLK
PCIP-1.4 – CNDSR AVAIL STM DMP ARMED C-9
PCIP-1.6 – RX ≥ 10% PWR P-10
PCIP-2.1 – SR TRN B RX TRIP BLK
PCIP-2.2 – IR TRN B RX TRIP BLK
PCIP-2.5 – SR RX TRIP BLK PERM P-6
PCIP-3.2 – PR TRN A LO SETPT RX TRIP BLK
PCIP-4.2 – PR TRN B LO SETPT RX TRIP BLK
1-SSII2 – Train B MDAFW is Solid Red

Operating Test : NRC	Scenario # 2	Event # 1		Page 7 of 50	
Event Description: Loss of Inverter (IV1PC1).					

Time	Position	Applicant's Actions or Behavior
Simulator Operator : When directed, execute Event 1 (Key 1) - ED07A, Loss of Protection Bus IV1PC1.		
Indications Available: **10B-1.16 – 118V CHAN I INV TRBL** **5A-1.3 – RC LOOP 1 1 OF 3 FLO LO** **5A-2.3 – RC LOOP 2 1 OF 3 FLO LO** **5A-3.3 – RC LOOP 3 1 OF 3 FLO LO** **5A-4.3 – RC LOOP 4 1 OF 3 FLO LO** **Protection Channel 1 Windows on TSLB 1 through 7 and 9 lit** **Numerous Other Loss of Protection Bus 1PC1 (Channel 1) Alarms**		
	RO/BOP	RECOGNIZE loss of Protection Bus 1PC1.
Examiner Note: Primary side actions include controlling Pressurizer pressure and level due to a loss of Letdown. **Secondary side actions include controlling Steam Generator (SG) levels in SGs 1-01 and 1-04 when Main Feedwater Pump speed lowers.**		
	RO/BOP	Take actions to place affected controllers in manual and control parameters within normal control bands.
	US	DIRECT performance of ABN-603, Loss of Protection or Instrument Bus, Section 2.0, Loss of Protection Bus
Examiner Note: The following steps are from ABN-603, Loss of Protection or Instrument Bus, Section 2.0, Loss of Protection Bus		
Simulator Operator: If contacted, REPORT Fan Failure Alarm is LIT on IV1PC1.		
	US/RO	Verify loss of protection bus did NOT cause - REACTOR TRIP [Step 2.3.1]
	US	Verify Unit in MODE 1, 2, 3, OR 4 [Step 2.3.2]
NOTE: Step 3 is a continuous action step.		

Operating Test : NRC	Scenario # 2	Event # 1	Page 8 of 50

Event Description: Loss of Inverter (IV1PC1).

Time	Position	Applicant's Actions or Behavior
	RO/BOP	Manually CONTROL parameters to maintain OR restore to normal as follows: [Step 2.3.3]
		• Place 1/1-RBSS, CONTROL ROD BANK SELECT Switch in MANUAL [Step 2.3.3a]

NOTE: Step b. RNO should be performed for loss of uPC1 since HCV-182 is failed open. Alignment of charging to RCP seals only may be performed prior to this step and should be verified as part of step b. performance

Time	Position	Applicant's Actions or Behavior
	RO	• VERIFY RCP seal injection – WITHIN NORMAL OPERATING RANGE. [Step 2.3.3b]
		• Manually CONTROL 1-FK-121, CCP CHG FLO CTRL Valve and charge to RCP Seals ONLY. [Step 2.3.3b RNO]
		• CLOSE 1/1-8105 or 1/1-8106, CHRG PMP TO RCS ISOL VLV and adjust charging to seals only. [Step 2.3.3b RNO]
	RO	• VERIFY Pressurizer level controlled – BETWEEN 25% AND 70%. [Step 2.3.3c]

NOTE: Step 3.d. RNO should be performed (pressurizer master controller in manual) if uPC1 is the lost bus. This will preclude potential PORV lift when the bus is re-energized.

Time	Position	Applicant's Actions or Behavior
	RO	• VERIFY Pressurizer pressure within NORMAL OPERATING RANGE FOR CONDITIONS [Step 2.3.3d]

Operating Test : NRC	Scenario # 2	Event # 1	Page 9 of 50
Event Description: Loss of Inverter (IV1PC1).			

Time	Position	Applicant's Actions or Behavior
		• VERIFY Steam Generator levels being controlled – BETWEEN 60% AND 70%. [Step 2.3.3.e]
		• MANUALLY control Steam Generator levels and Feed Pumps as necessary to maintain level. [Step 2.3.3.e RNO]
		• PLACE 1-SK-509A, FWPT MASTER SPD CTRL in MANUAL. [Step 2.3.3.e RNO]
		• PLACE 1-FK-510, SG 1 FW FLO CTRL in MANUAL and CONTROL SG 1-01 level. [Step 2.3.3.e RNO]
		• PLACE 1-FK-540, SG 4 FW FLO CTRL in MANUAL and CONTROL SG 1-04 level. [Step 2.3.3.e RNO]
	US	• GO TO Step 6 [Step 2.3.3f]
CAUTION: Reenergizing the affected protection bus may cause instrumentation spikes on controlling channels which may in turn initiate unwanted actions.		
	US	VERIFY Unit – IN MODE 1 [Step 2.3.6]
NOTE: Rod Control should remain in MANUAL until all Tave channels are operable.		
	RO	• Place control rods in MANUAL [Step 2.3.6a]
	RO	• Select LOOP 1 on 1-TS-412T, TAVE CHAN DEFEAT switch [Step 2.3.6b]
		• DISPATCH an operator to REENERGIZE Protection Bus 1PC1. [Step 2.3.6.c]
		• VERIFY PCIP, Window 3.4 – TURB LOAD REJ STM DMP ARMED C-7, not ARMED. [Step 2.3.6.d]
		• RESTORE 1-TS-412T, T_{AVE} CHAN DEFEAT Switch to the NONE Position. [Step 2.3.6.e]
Simulator Operator: **When contacted to re-energize 1PC1, WAIT 2 minutes then EXECUTE remote function EDR01 (Key 10) Transfer 1PC1 to the Alternate Power Supply.**		

Operating Test : NRC	Scenario # 2	Event # 1	Page 10 of 50
Event Description: Loss of Inverter (IV1PC1).			

Time	Position	Applicant's Actions or Behavior
		CAUTION: To prevent rods from potentially stepping, allow a minimum of 2 minutes for Tavg circuitry to stabilize following manipulation of u-TS-412T before returning rod control to Auto.
		Examiner Note: The crew should perform a reactivity calculation, conduct a reactivity brief, and restore Control Bank D to the pre-event position prior to placing rod control back in auto.
	US/RO	• PLACE 1/1-RBSS, CONTROL ROD BANK SELECT Switch in AUTO [Step 2.3.6f]
	US	• INVESTIGATE and INITIATE corrective action on loss of power to protection bus [Step 2.3.6g]
	US	GO TO Step 9 [Step 2.3.7]
	US	VERIFY Unit – IN MODE 1, 2, 3 OR 4 [Step 2.3.9]
		Examiner Note: The following actions will be performed upon Bus 1PC1 restoration.
	US	CHECK status of affected control systems and instrumentation [Step 2.3.10]
	BOP	• Using Attachments 1 AND 2, verify control functions AND instruments – REACTING NORMALLY TO SIGNALS: [Step 2.3.10a]
		• Recorders operating with event time properly labeled per ODA-104 • Automatic control systems – RESPONDING NORMALLY • Instrumentation indication within normal range as compared to redundant instruments.

Operating Test : NRC	Scenario # 2	Event # 1	Page 11 of 50
Event Description: Loss of Inverter (IV1PC1).			

Time	Position	Applicant's Actions or Behavior
		• RESTORE Feedwater System to normal operation. [Step 2.3.10.a]
		• PLACE 1-FK-510, SG 1 FW FLO CTRL in AUTO.
		• PLACE 1-FK-540, SG 4 FW FLO CTRL in AUTO.
		• PLACE 1-SK-509A, FWPT MASTER SPD CTRL in AUTO.
	BOP	• Ensure the Power Range Flux Rate MODE Selectors –RESET [Step 2.3.10b]
		• Power Range Flux Rate Mode Selector on Drawer N-41A and VERIFY Positive Rate Mode alarm light DARK.
	RO	• RESTORE Charging and Letdown: [Step 2.3.10c]
		• CLOSE 1-HC-182, Seal Flow Control Valve. [Step 2.3.10.c.1)]
		• ENSURE 1/1-8105 and 1/1-8106, Charging Isolation Valves are OPEN. [Step 2.3.10.c.2)]
		• Adjust 1-HC-182, Seal Flow Control Valve and 1-FK-121, Charging Flow Control Valve to CONTROL RCP seal flow. [Step 2.3.10.c.3)]
		• RESTORE Letdown flow using ABN-105 or Control Board Job Aid. [Step 2.3.10.c.4)]
<u>Examiner Note</u>: The following steps are from the Job Aid to restore letdown.		
	RO	a. ENSURE Letdown Isolation Valves – OPEN
		• 1/1-LCV-459, LTDN ISOL VLV
		• 1/1-LCV-460, LTDN ISOL VLV
		b. ENSURE 1-PK-131, LTDN HX OUT PRESS CTRL in MANUAL and 30% (75 gpm) or 50% (120 gpm) DEMAND
		c. ENSURE 1-TK-130, LTDN HX OUT TEMP CTRL in MANUAL and 50% DEMAND
		d. ADJUST Charging to desired flow and MAINTAIN Seal Injection flow between 6 and 13 gpm
		e. OPEN the desired Orifice Isolation Valves
		• 1/1-8149A, LTDN ORIFICE ISOL VLV

Operating Test : NRC	Scenario # 2	Event # 1	Page 12 of 50
Event Description: Loss of Inverter (IV1PC1).			

Time	Position	Applicant's Actions or Behavior
		• 1/1-8149B, LTDN ORIFICE ISOL VLV
		• 1/1-8149C, LTDN ORIFICE ISOL VLV
		f. ADJUST 1-PK-131, LTDN HX OUT PRESS CTRL to ~310 psig on 1-PI-131, LTDN HX OUT PRESS then PLACE in AUTO.
		g. ADJUST 1-TK-130, LTDN HX OUT TEMP CTRL to obtain ~95ºF on 1-TI-130, LTDN HX OUT TEMP, then place in AUTO.
	US	EVALUATE Technical Specifications. [Step 2.3.11]
		• LCO 3.8.7.A, Inverters – Operating
		• CONDITION A - One required inverter inoperable • ACTION A.1 - Restore inverter to OPERABLE status within 24 hours
<u>Examiner Note:</u> LCO 3.8.9.B is entered when power is lost and exited when power is restored.		
		• LCO 3.8.9.B, Distribution Systems - Operating
		• CONDITION B - One AC vital bus subsystem inoperable • ACTION B.1 - Restore AC vital bus subsystem to OPERABLE status within 2 hours
	US	REFER to EPP-201 [Step 2.3.12]
	US	Notify System Engineering to expedite trouble shooting and any needed repairs [Step 2.3.13]
	US	Initiate a Condition Report per STA-421, if required [Step 2.3.14]
When Technical Specifications are addressed, or at Lead Examiner discretion, PROCEED to Event 2.		

Operating Test : NRC	Scenario # 2	Event # 2	Page 13 of 50
Event Description: Station Service Water Pump 1-02 trip			

Time	Position	Applicant's Actions or Behavior
		Simulator Operator: **When directed, EXECUTE Event 2 (Key 2).** **- SW01B, Station Service Water Pump 1-02 trip.**
		Indications Available: **1-1.8 – SSWP 1 / 2 OVRLOAD / TRIP** **1-2.11 – CCP 2 L/O CLR SSW RET FLO LO** **1-2.12 – SIP 2 L/O CLR SSW RET FLO LO** **1-4.8 – CSP 2 & 4 BRG CLR SSW RET FLO LO** **1-HS-4251A, Station Service Water Pump 1-02 amber MISMATCH and white TRIP lights lit**
	BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE 1-HS-4251A, Service Water Pump 1-02 amber MISMATCH and white TRIP lights LIT.
	US	DIRECT performance of ABN-501, Station Service Water System Malfunction, Section 2.0, Station Service Water Pump Trip.
		Examiner Note: **The following steps are from ABN-501, Station Service Water System Malfunction, Section 2.0, Station Service Water Pump Trip**
		NOTE: • The diesel generator can be operated, with load, for approximately one minute without SSW flow and not affect diesel performance. • When a fault exists on the 6.9KV safeguard bus, the SSW pump will not be running to supply cooling water to the DG. The time this condition exists should be minimized (approximately 15 minutes) to prevent damage to the DG. • Diamond step 1 denotes Initial Operator Actions.
		Examiner Note: **Diamond steps (◊) are Initial Operator Actions.**
	◊ BOP ◊	PLACE CS-1DG2E, Train B Diesel Generator Emergency Start/Stop handswitch in PULLOUT. [Step 2.3.1]
	BOP	VERIFY Train A SSW Pump – RUNNING. [Step 2.3.2]

Operating Test : NRC	Scenario # 2	Event # 2	Page 14 of 50				
Event Description: Station Service Water Pump 1-02 trip							

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY Train A CCW Pump – RUNNING. [Step 2.3.3]

Simulator Operator: When contacted to investigate SSW Pump 1-02, WAIT 2 minutes and REPORT the 50/51 overcurrent relays on Phases B & C are tripped at the breaker.

CAUTION: With loss of SSW flow to the CCP oil cooler, CCP bearing damage will occur after approximately 13 minutes.

NOTE: The CCW pump on the affected train may be left operating at the discretion of the Shift Manager. However, with this pump operating, the affected SSW Pump will have an Auto Start Signal to it.

Time	Position	Applicant's Actions or Behavior
	RO/BOP	VERIFY equipment in the affected train (B) – NOT REQUIRED FOR OPERATION: [Step 2.3.4]
		• Centrifugal Charging Pump 1-02 • Diesel Generator 1-02 • Component Cooling Water Pump 1-02 • Safety Injection Pump 1-02 • Containment Spray Pumps 1-02 & 1-04

CAUTION: Do not place pump handswitch in STOP if pump tripped (white TRIP light). This will reset 86M relay (white TRIP light) and may result in an automatic restart.

Time	Position	Applicant's Actions or Behavior
	RO/BOP	PLACE equipment on affected train (B) in PULLOUT. [Step 2.3.5]
		• Centrifugal Charging Pump 1-02 • Safety Injection Pump 1-02 • Containment Spray Pumps 1-02 & 1-04 • Station Service Water Pump 1-02 (may leave as is due to CAUTION)
	BOP	CHECK status of affected train (B) CCW Pump. [Step 2.3.6]

Operating Test :	NRC	Scenario #	2	Event #	2	Page	15	of 50
Event Description:	Station Service Water Pump 1-02 trip							

Time	Position	Applicant's Actions or Behavior
		• VERIFY CCW Pump – NOT RUNNING. [Step 2.3.6.a]
		• CONTINUE with Step 7. [Step 2.3.6.a RNO]
	US	INITIATE a work request per STA-606. [Step 2.3.7]
	US	REFER to EPP-201. [Step 2.3.8]
	US	EVALUATE Technical Specifications. [Step 2.3.9]
		• LCO 3.7.8.B, Station Service Water System.
		• CONDITION B - One SSWS Train inoperable. • ACTION B.1 - Restore SSWS Train to OPERABLE status within 72 hours.
		• LCO 3.8.1.B, AC Sources - Operating.
		• CONDITION B - One DG inoperable. • ACTION B.1 - Perform SR 3.8.1.1 for the required offsite circuit(s) within 1 hour <u>AND</u> once per 8 hours thereafter, <u>AND</u> • ACTION B.2 - Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable within 4 hours from discovery of Condition B concurrent within inoperability of redundant required feature(s), <u>AND</u> • ACTION B.3.1 - Determine OPERABLE DG(s) is not inoperable due to common cause failure within 24 hours, <u>OR</u> • ACTION B.3.2 - Perform SR 3.8.1.1 for OPERABLE DG(s) within 24 hours. <u>AND</u> • ACTION B.4 - Restore DG to OPERABLE status within 72 hours.
<u>Simulator Operator</u>: If contacted, INFORM the Unit Supervisor that another operator will perform required Technical Specification Surveillance.		
	US	COMPLETE OPT-215 verification within one hour. [Step 2.3.10]

Operating Test : NRC	Scenario # 2	Event # 2	Page 16 of 50
Event Description: Station Service Water Pump 1-02 trip			

Time	Position	Applicant's Actions or Behavior
	US	SUBMIT a Condition Report per STA-421. [Step 2.3.11]

Ensure Rx Make-up restored to Auto, prior to inserting the next malfunction.

When Technical Specifications are addressed, or at Lead Examiner discretion, PROCEED to Event 3.

Operating Test : NRC	Scenario # 2	Event # 3	Page 17 of 50
Event Description: CV16A, Volume Control Tank (LT-112) fails low			

Time	Position	Applicant's Actions or Behavior
Simulator Operator: **When directed, EXECUTE Event 3. (Key 3)** **- CV16A, Volume Control Tank (LT-112) failed low.** ***Ensure Rx Make-up restored to Auto, prior to inserting the next malfunction.***		
Indications Available: **6A-3.5 – VCT LVL LO** **6A-4.5 – VCT LVL LO-LO** **1-LI-112A – VCT LVL level indication fails low**		
	RO	RECOGNIZE VCT level transmitter (LT-112) failed low.
	RO	STOP Auto Makeup by PLACING 1/1-MU, RCS MU MAN ACT in STOP.
	US	DIRECT performance of ALM-0061A, 1-ALB-6A, Window 4.5 - VCT LVL LO-LO **or** ABN-105, Chemical and Volume Control System Malfunction, Section 6.0, Reactor Makeup System Malfunction.
Examiner Note: **The following steps are from 1-ALB-6A, Window 4.5 - VCT LVL LO-LO.**		
Simulator Operator: **When maintenance is contacted, (Wait 2 minutes) Inform the control room that cleaners have bumped the transmitter and it appears the equalizing valve is open. Request permission to close the equalizing valve.** **When permission is given. DELETE malfunction CV16A and REPORT I&C has closed the equalizing valve and the level transmitter appears to be operating normally.**		
	RO	IF the charging pump suction shifts to the RWST and the PDP is operating, THEN perform the following per SOP-103A: Step is N/A [Step 1]
	RO	MONITOR VCT level on 1-LI-112A, VCT LVL and 1-LI-185, VCT LVL. [Step 2]
		• If both VCT levels indicate low, ENSURE charging pump suction is aligned to the RWST. Step is N/A [Step 2.A]

Operating Test :	NRC	Scenario #	2	Event #	3	Page	18	of	50
Event Description:	CV16A, Volume Control Tank (LT-112) fails low								

Time	Position	Applicant's Actions or Behavior
		• MONITOR other indication for possible charging pump gas intrusion such as: [Step 2.B] • Window 1.5 – VCT PRESS H/LO • Window 1.8 – PDP SUCT STAB LVL HI-HI • Window 3.4 – CHRG FLO HI/LO • CHRG PMP pressure or flow oscillations
		• If gas intrusion is indicated, REFER to ABN-105 for Gas Binding/Cavitation of Charging Pumps. [Step 2.C]
	RO	MONITOR charging and letdown flow on 1-FI-121A, CHRG FLO, and 1-FI-132, LTDN FLO. [Step 3]
		• If charging flow is > 15 gpm above letdown flow, REFER to ABN-103 and ABN-105. [Step 3.A]
	RO	IF BOTH VCT levels indicate low, THEN perform the following. Step is N/A [Step 4]
	RO	IF BOTH VCT levels indicate different, THEN perform the following: [Step 5]
		• CHECK 1-PI-115, VCT PRESS (should be approximately 30 psig.) [Step 5.A]
		• IF 1-LI-112A is low WITH 1-LI-185 AND VCT pressure high, THEN check 1-LT-0112, CVCS VOLUME CONTROL TANK 1-01 LEVEL TRANSMITTER for malfunction. [Step 5.B]
		• STOP Auto Makeup by PLACING 1/1-MU, RCS MU MAN ACT in STOP. [Step 5.B.1)]
		• REDUCE VCT level on 1-LI-185 to between 46% and 56% by placing 1/1-LCV-112A, VCT LVL CTRL VLV in HUT. [Step 5.B.2)]
		• ENSURE 1-LI-185, VCT LVL and 1-PI-115, VCT PRESS are decreasing. [Step 5.B.3)]
		• REFER to ABN-105. [Step 5.B.4)]
	RO	• IF 1-LI-185 is low WITH 1-LI-112A AND VCT pressure normal, check 1-LT-0185, CVCS VOLUME CONTROL TANK 1-01 LEVEL TRANSMITTER 0185 for malfunction. Step is N/A [Step 5.C]

Operating Test : NRC	Scenario # 2	Event # 3	Page 19 of 50
Event Description: CV16A, Volume Control Tank (LT-112) fails low			

Time	Position	Applicant's Actions or Behavior
	RO	• When VCT level has lowered to desired value, PLACE 1/1-LCV-112A, VCT LVL CTRL VLV in VCT. [Step 5.D]
	RO	VERIFY 1-LK-112C, VCT LVL CTRL potentiometer is set per TDM-203A. [Step 6]
	US	CORRECT the condition or initiate a work request per STA-606. [Step 7]
Examiner Note:		**The following steps are from ABN-105, Chemical and Volume Control System Malfunction, Section 6.0, Reactor Makeup System Malfunction.**
NOTE:		Normal Operating Mode of the Reactor Makeup System includes the following Modes: • Automatic Mode • Borate Mode • Dilute Mode • Alternate Dilute Mode
	RO	VERIFY Reactor Makeup System in – NORMAL OPERATING MODE [Step 6.3.1]
		• ENSURE Reactor makeup System aligned per SOP-104A [Step 6.3.1.a]
		• PERFORM the applicable subsection of SOP-104A for normal operations. [Step 6.3.1.c]
		• RETURN to procedure and step in effect. [Step 6.3.1.c]
Examiner Note:		**The following steps are from SOP-104A, Reactor Make-up and Chemical Control System, Section 5.1.1, Automatic Mode.**

Operating Test : NRC	Scenario # 2	Event # 3	Page 20 of 50				
Event Description: CV16A, Volume Control Tank (LT-112) fails low							
Time	Position	Applicant's Actions or Behavior					

NOTE:
- When a blended flow concentration of >1600 PPM is desired, the maximum boric acid flow should NOT be expected to exceed 27 gpm. Therefore, section 5.1.6, Manual Blended Makeup, or 5.1.7, Multiple Manual Blended Makeups should be used for makeups >1600 ppm.
- 1/1-FCV-110A has non-linear flow characteristics below 4 gpm which could cause an inadvertent Boration during AUTO makeup to RCS. Therefore, for blended flow makeups, only Manual Blended Makeup should be used when B-10 Corrected RCS Boron Concentration is < 250 ppm. Sections 5.1.6 or 5.1.7 may be used, or 5.1.3, EOL Dilution with RCS Cb < 250 ppm.

Time	Position	Applicant's Actions or Behavior
		ENSURE the prerequisites of Section 2.1 and 2.2 are met. [Step 5.1.1.A]
		IF any of the following conditions apply, THEN NOTIFY Chemistry to prepare a sample of the blended flow. [Step 5.1.1.B] • Anticipated makeup will be > 1000 gallons within a one hour period. • Desired blended flow concentration will be > 1300 ppm (shutdown only) • 1-FK-110, BA BLNDR FLO CTRL potentiometer will be adjusted to > 6.0 (24 gpm)
		• ENSURE 1/1-MU, RCS MU MAN ACT in STOP. [Step 5.1.1.C]
		• ENSURE the following handswitches are in AUTO, AND the valves are CLOSED: [Step 5.1.1.D]
		• 1/1-FCV-111A, RMUW BLNDR FLO CTRL VLV
		• 1/1-FCV-111B, RCS MU TO VCT ISOL VLV
		• 1/1-FCV-110A, BA BLNDR FLO CTRL VLV
		• 1/1-FCV-110B, RCS MU TO CHRG PMP SUCT ISOL VLV
		• SET 1-FK-111, RMUW BLNDR FLO CTRL for approximately 90 gpm (5.63), OR as required. [Step 5.1.1.E]
		• SET 1-FK-110, BA BLNDR FLO CTRL pot to provide a blended flow approximately equal to the B-10 Corrected RCS Boron Concentration. [Step 5.1.1.F]

Operating Test : NRC	Scenario # 2	Event # 3	Page 21 of 50
Event Description: CV16A, Volume Control Tank (LT-112) fails low			

Time	Position	Applicant's Actions or Behavior
		$127 \times \_\_\_\_ \frac{\text{B-10 Corr RCS } C_B}{\text{BAT } C_B} = \text{Boric Acid Flowrate } \_\_\_\_$ $\frac{\_\_\_\_\text{boric acid flowrate}}{4} = \text{1-FK-110 pot setting } \_\_\_\_$
		• PLACE 43/1-MU, RCS MU MODE SELECT in AUTO. [Step 5.1.1.G]
		• PLACE 1/1-MU, RCS MU MAN ACT in START. [Step 5.1.1.H]
When Reactor Makeup is returned to Automatic , or at Examiner's discretion proceed to Event 4		

Operating Test : NRC	Scenario # 2	Event # 4	Page 22 of 50
Event Description:	Heater Drain Pump Trip/ Automatic Turbine Runback Failure, Failure of Rods to Move In automatic		

Time	Position	Applicant's Actions or Behavior

Simulator Operator: **When directed, EXECUTE Event 4 (Key 4).**
- FW14B, Heater Drain Pump (1-02) trip.
- TC09I, Auto Turbine Runback failure.
- RD15A, Rods Fail to move in Auto

Indications Available:
9A-1.2 – HDP 1/2 OVRLOAD / TRIP
8B-2.8 – CNDS LP HTR BYP TRBL
8B-3.8 – CNDS LP HTR BYP VLV OPEN PV-2286
8B-4.8 – TURB GLND STM CNDSR CNDS FLO HI
6D-1.9 – ANY TURB RUNBACK EFFECTIVE (when Manual Runback initiated)
6D-1.10 – AVE T_{AVE}-T_{REF} DEV (when Manual Runback initiated)
1-HS-2603, HDP 2 TRIP light LIT
Steam Dump System Group 1 Valves OPEN

Time	Position	Applicant's Actions or Behavior
	RO/BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE trip of Heater Drain Pump 1-02 with no Automatic Turbine Runback and Control Rods not moving in automatic.
	US	DIRECT performance of ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 4.0, Heater Drain Pump Trip.

Examiner Note: **The following steps are from ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 4.0, Heater Drain Pump Trip.**

Examiner Note: **Diamond steps (◊) are Initial Operator Actions.**

CAUTION: Using Load Target to reduce load without rods in AUTO can result in excessive TAVE-TREF mismatch before C-7 activates. This mismatch may cause an SI when steam dumps trip open.

NOTE:
- Diamond step 1 denotes Initial Operator Actions.
- Automatic runback to 70% is approximately 812 MW.

Operating Test :	NRC	Scenario #	2	Event #	4	Page	23	of	50
Event Description:	Heater Drain Pump Trip/ Automatic Turbine Runback Failure, Failure of Rods to Move In automatic								

Time	Position	Applicant's Actions or Behavior
	◊ RO/BOP ◊	VERIFY automatic plant response. [Step 4.3.1]
	◊ RO ◊	• VERIFY Control Rods in – AUTO.
	◊ BOP ◊	• VERIFY Turbine Runback – IN PROGRESS.
	◊ RO/BOP ◊	• If Turbine Power is > approximately 800 MWe, PERFORM the following: [Step 4.3.1 RNO].
	◊ RO ◊	• ENSURE 1/1-RBSS, CONTROL ROD BANK SELECT in AUTO. [Step 4.3.1.a RNO]. • Rods will NOT move in AUTO, MANUAL rod control will be required
	◊ BOP ◊	• ENSURE Turbine Runback to 700 MWE initiated. [Step 4.3.1.b RNO]
		• DEPRESS "700 MWe" MANUAL RUNBACK button.
		• CLICK on "0/1" button.
		• CLICK on "Execute" then VERIFY Manual Runback in progress.
Simulator Operator:		**When contacted, REPORT an instantaneous ground overcurrent 50N relay on the breaker for Heater Drain Pump 1-02. Motor is hot with no indication of fire.**
	BOP	VERIFY Main Feed Flow to Steam Generators. [Step 4.3.2]
		• Main Feed Pump – AT LEAST ONE RUNNING. [Step 4.3.2.a]
		• Main Feedwater pump suction pressure – GREATER THAN 250 PSIG. [Step 4.3.2.b]
NOTE: Differential pressure between feedwater and steamline may decrease following a Turbine Runback. The following computer points may aid the operator: • U5002A FW-MS HDR DP • U5003A DELTA PROGRAM-ACTUAL DP • P5446A FW STM FLOW SETPOINT		

Operating Test : NRC	Scenario # 2	Event # 4	Page 24 of 50
Event Description:	Heater Drain Pump Trip/ Automatic Turbine Runback Failure, Failure of Rods to Move In automatic		

Time	Position	Applicant's Actions or Behavior
		• Feedwater header pressure – MAINTAINED GREATER THAN MAIN STEAM HEADER PRESSURE. [Step 4.3.2.c]
		• Main Feedwater – ALIGNED. [Step 4.3.2.d]
	BOP	VERIFY Steam Generator water level – STABLE OR TRENDING TO NORMAL OPERATING RANGE. [Step 4.3.3]
NOTE: Control Rod insertion should be allowed to continue even if ΔI is outside the band. Continued rod insertion is required to return Tave to Tref as soon as possible so that steam demand is reduced.		
	BOP	VERIFY T_{AVE} – TRENDING TO T_{REF}. [Step 4.3.4] • 1-TI-412A, AVE TAVE – TREF DEV
CAUTION: Reactor power must be established at a value within the capability of available feedwater. Auxiliary feedwater pumps can supply approximately 6% reactor power.		
	RO/BOP	STABILIZE Reactor power using one or more of the following: [Step 4.3.5]
		• Control Rods • Steam Dumps • Boration • Turbine Load
	BOP	VERIFY Steam Generator Feedwater Flow Control Valves – IN AUTO. [Step 4.3.6] • 1-FK-510, SG 1 FW FLO CTRL • 1-FK-520, SG 2 FW FLO CTRL • 1-FK-530, SG 3 FW FLO CTRL • 1-FK-540, SG 4 FW FLO CTRL

Operating Test : NRC	Scenario # 2	Event # 4	Page 25 of 50
Event Description:	Heater Drain Pump Trip/ Automatic Turbine Runback Failure, Failure of Rods to Move In automatic		

Time	Position	Applicant's Actions or Behavior
	RO	VERIFY the following: [Step 4.3.7]
		• Control Rods – ABOVE ROD INSERTION LIMIT. [Step 4.3.7.a]
		• VERIFY SDM or initiate boration to restore SDM within 1 hour and restore Rods above insertion limits with 2 hours per TS 3.1.6 [Step 4.3.7.a RNO]
		• Δ Flux – (AFD) WITHIN LIMITS. [Step 4.3.7.b]
Examiner Note:	**Events during this scenario will result in exceeding the Rod Insertion Limits (RIL). The RO should inform the SRO when ALB-6D, Window 2.7 – ANY CONTROL ROD BANK AT LO-LO LIMIT is LIT. Technical Specifications must be referenced.**	
	US	EVALUATE Technical Specifications.
		• LCO 3.1.6.A, Control Bank Insertion Limits.
		• CONDITION A - Control bank insertion limits not met. • ACTION A.1.1 - Verify SDM to be within the limits provided in the COLR within one hour, <u>OR</u> • ACTION A.1.2 - Initiate Boration to restore SDM to within limit within one hour, <u>AND</u> • ACTION A.2 - Restore control bank(s) to within limits within 2 hours.
	BOP	<u>WHEN</u> steam dumps have closed, <u>THEN</u> reset steam dump arming signal (C-7 interlock). [Step 4.3.8]
		• 43/1-SD, STM DMP MODE SELECT
Examiner Note:	**LP Feed Heater Bypass Valve closure is not performed due to time constraints.**	
	BOP	VERIFY 1-HS-2286, Low Pressure Feedwater Heater Bypass Valve – CLOSED. [Step 4.3.9]
	US	NOTIFY QSE Generation Controller and update GAPS to "Create Current Condition" for the down power. [Step 4.3.10]
	US	INITIATE repairs per STA-606. [Step 4.3.11]

Operating Test : NRC	Scenario # 2	Event # 4	Page 26 of 50
Event Description:	Heater Drain Pump Trip/ Automatic Turbine Runback Failure, Failure of Rods to Move In automatic		

Time	Position	Applicant's Actions or Behavior
	US	Check Chemistry Sampling Requirement: [Step 4.3.12]
		• SG ARVS - REMAINED CLOSED -AND- • TDAFW Pump – REMAINED STOPPED [Step 4.3.12.a]
		• Verify Reactor Power change - LESS THAN 15% RTP WITHIN ONE HOUR. [Step 4.3.12.b]
	BOP	Reset Turbine Runback per ABN-401 [Step 4.3.13]
Examiner Note:		**The following steps are from ABN-401, Main Turbine Malfunction, Section 8.0, Turbine Reloading after Runback.**
	BOP	VERIFY alarm 6D-1.9, ANY TURB RUNBACK EFFECTIVE – DARK. [Step 8.3.1]
	BOP	In the Load Control Section, ENSURE Load Rate Setpoint Controller is SET to support reload or current plant conditions. [Step 8.3.2]
	BOP	In the Load Control Section, ENSURE Load Target Setpoint Controller is set for actual MWe. [Step 8.3.3]
	BOP	If Manual Runback was used, TURN OFF the appropriate Subloop Controller on the TG Control Display in the MANUAL RUNBACKS Section. [Step 8.3.4]
	BOP	VERIFY Runback is RESET. [Step 8.3.5]
	BOP	VERIFY Runback – GREATER THAN 15% WITHIN ONE HOUR and CONTACT Chemistry. [Step 8.3.6]
	BOP	CONTROL Turbine Load as required per IPO-003A. [Step 8.3.7]

Operating Test :	NRC	Scenario #	2	Event #	4	Page	27	of	50
Event Description:	Heater Drain Pump Trip/ Automatic Turbine Runback Failure, Failure of Rods to Move In automatic								

Time	Position	Applicant's Actions or Behavior

When Technical Specifications have been addressed, and the runback has been reset, or at Lead Examiner's discretion, PROCEED to Events 5, 6, 7, and 8.

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 28 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer		

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Events 5, 6, 7, and 8 (Key 5).** **- ED01, Loss of Offsite Power.** **- EG15A, DG 1-01 fails to auto-start** **- OVRD, Pressurizer Steam Space Sample Valves fail to Auto Close.** **- RC08A2, LBLOCA** **- RH01C, RHR Pump 1-01 fails to start on sequencer**
Indications available: **Numerous Reactor Trip and Loss of Offsite Power Alarms.**		
	RO/BOP	RECOGNIZE Reactor Trip due to Loss of Offsite Power.
	US	DIRECT performance of EOP-0.0A, Reactor Trip or Safety Injection or ECA- 0.0A, Loss of All AC Power.
Simulator Operator:		**When Unit 1 trips, Announce Unit 2 Reactor Trip.**
Examiner Note:		**Crew may recognize a Loss of All AC Power event in progress and immediately enter ECA-0.0A, Loss of All AC Power as opposed to EOP-0.0A, Reactor Trip or Safety Injection.**
Examiner Note:		**EOP-0.0A, Reactor Trip or Safety Injection steps begin here.**
	RO	VERIFY Reactor Trip: [Step 1]
		• VERIFY the following: [Step 1.a]
		• VERIFY Reactor Trip Breakers – OPEN.
		• VERIFY Neutron flux – DECREASING.
		• VERIFY all Control Rod Position Rod Bottom Lights – ON. [Step 1.b]
Examiner Note:		**All DRPI indication will be lost due to the Loss of Offsite Power. The crew will be required to Emergency Borate 3600 gallons of 7000 ppm boric acid for a Loss of DRPI if verification of "All Rod Bottom Lights – ON" is not made prior to the loss of DRPI. However, until power is restored to Bus 1EA1 via DG 1-01 the crew will be unable to start a CCP to initiate Emergency Boration. After DG 1-01 is powering 1EA1 a LBLOCA will occur and the crew should verify Emergency Boration via SI flow in accordance with ABN-107, Attachment 4.**

Operating Test :	NRC	Scenario #	2	Event #	5, 6, 7, 8, 9	Page	29	of 50

Event Description: Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY Turbine Trip: [Step 2]
		• VERIFY all HP Turbine Stop Valves – CLOSED. [Step 2]
	BOP	VERIFY Power to AC Safeguards Buses: [Step 3]
		• VERIFY AC Safeguards Buses – AT LEAST ONE ENERGIZED. [Step 3.a]
		• GO to ECA-0.0A, Loss of All AC Power, Step 1. [Step 3.a RNO a]
Examiner Note:		**ECA- 0.0A, Loss of All AC Power steps begin here. Power will not be available to Train B components throughout the remainder of the scenario.**
NOTE: CSF Status Trees should be monitored for information only. FRGs should not be implemented.		
	RO	VERIFY Reactor Trip: [Step 1]
		• VERIFY Reactor Trip Breakers – AT LEAST ONE OPEN.
		• VERIFY Neutron flux – DECREASING.
	BOP	VERIFY Turbine Trip: [Step 2]
		• VERIFY all HP Turbine Stop Valves – CLOSED.
CRITICAL TASK STATEMENT		**Isolate Reactor Coolant System Leakage Paths in accordance with ECA-0.0A, Loss of All AC Power prior to initiation of Steam Generator depressurization.**
	RO	CHECK If RCS Is Isolated: [Step 3]
	RO	• CHECK Letdown Isolation Valves – CLOSED. [Step 3.a]
		• 1/1-LCV-459 and 1/1-LCV-460

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9 Page 30 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer	
Time	Position	Applicant's Actions or Behavior

Examiner Note:		**The Letdown Isolation Valves are interlocked with the Letdown Orifice Isolation Valves. The Letdown Isolation Valves cannot be closed until the Letdown Orifice Isolation Valves are closed.**
	RO	• CLOSE Letdown Isolation Valves. [Step 3.a RNO]
		• PLACE 1/1-8149A AND 1/1-8149B, Letdown Orifice Isolation Valves in CLOSE.
CT-1		• PLACE 1/1-LCV-459 AND 1/1-LCV-460, Letdown Isolation Valves in CLOSE. [Step 3.a RNO]
	RO	• CHECK Pressurizer Power Operated Relief Valves – CLOSED. [Step 3.b]
	RO	• CHECK Excess Letdown Isolation Valves – CLOSED. [Step 3.c]
		• 1/1-8153 and 1/1-8154
	RO	• CHECK Primary Sample System Isolation Valves – CLOSED. [Step 3.d]
		• 1/1-4165A and 1/1-4167A
CT-1	RO	• CLOSE Primary Sample System Isolation Valves. [Step 3.d RNO]
		• PLACE 1-HS-4165A and 1-HS-4167A, Primary Sample System Isolation Valves in CLOSE. [Step 3.d RNO]
	RO/BOP	VERIFY AFW Flow – GREATER THAN 460 GPM: [Step 4]
CRITICAL TASK STATEMENT		**Restore Power to Bus 1EA1 in accordance with ECA-0.0A, Loss of All AC Power, prior to exit from ECA-0.0A.**
Examiner Note:		**DG 1-02 is in PULL-OUT due to the loss of SSW Pump 1-02. Steps in ECA-0.0A to energize the Train B Safeguards Bus via the DG will not be performed.**

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 31 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer		

Time	Position	Applicant's Actions or Behavior
	BOP	RESTORE Power to Any AC Safeguards Bus: [Step 5]
		• ENERGIZE selected AC Safeguards Bus with Diesel Generator. [Step 5.a]
		• VERIFY Diesel Generator 1-01 – RUNNING. [Step 5.a.1)]
		• Start Diesel Generator 1-01 As Follows : [Step 5.a. RNO 1)]
CT-2	BOP	• Perform an Emergency Start. [Step 5.a.1) RNO 1)A)] • IF the diesel generator is NOT running, THEN perform a Normal Start. [Step 5.a.1) RNO 1)B)]
	BOP	• Check Selected Diesel Generator 1-01 Output Breaker CLOSED [Step 5.a.2)]
	BOP	• ENERGIZE remaining AC Safeguards Bus with Diesel Generator 1-02. [Step 5.b]
	US	• DETERMINE Diesel Generator 1-02 – NOT RUNNING and In PULL-OUT. [Step 5.b.1)]
	BOP	• PERFORM Emergency Start on Diesel Generator 1-02. [Step 5.b.1) RNO 1)A)] Step is N/A
	BOP	• PERFORM Normal Start on Diesel Generator 1-02. [Step 5.b.1) RNO 1)B)] Step is N/A
	US	• DETERMINE Diesel Generator 1-02 – NOT RUNNING and GO to Step 5c. [Step 5.b.1) RNO 1)C)]
	US	• VERIFY AC Safeguards Buses – AT LEAST ONE ENERGIZED. [Step 5.c]
	US	• Return to procedure and step in effect AND implement FRGs as necessary. [Step 5.d]

Examiner Note: **120 Seconds after the Emergency Stop/Start handswitch of DG 1-01 was placed in Emergency Start a LBLOCA will occur. An automatic Safety Injection will occur after the transition back to EOP-0.0A has been made. Critical Safety Function Status Tree Orange Paths will exist sometime after the LBLOCA occurs on Integrity and Containment. The crew should implement these FRGs as they come in as FRGs should now be implemented as required.**

Examiner Note: **The following steps are from ABN-107, Attachment 4, Transfer of Charging Pump Suction to the RWST and the Job Aid for verifying Emergency Boration via SI flow.**

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 32 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer		

Time	Position	Applicant's Actions or Behavior
	RO/BOP	IF Safety Injection actuated (1/1-LCV-112D OR 1/1-LCV-112E OPEN), THEN perform the following steps: [Step 1]
		• VERIFY ONE of the following valves are OPEN: [Step 1.a] • 1/1-LCV-112D, RWST TO CHRG PMP SUCT VLV OR • 1/1-LCV-112E, RWST TO CHRG PMP SUCT VLV
		• VERIFY the following valves CLOSED: [Step 1.b] • 1/1-LCV-112B, VCT TO CHRG PUMP SUCT VLV AND • 1/1-LCV-112C, VCT TO CHRG PUMP SUCT VLV
		• VERIFY at least ONE CCP running: [Step 1.c] • 1/1-APCH1, CCP 1 (Automatically started on the BO Sequencer) • 1/1-APCH2, CCP 2 (De-energized)
		• VERIFY 1-FI-917, CCP SI FLOW indication [Step 1.d]
		• IF CCP SI FLOW can NOT be verified, THEN initiate Emergency Boration Flow per another method of ABN-107 [Step 1.e]

NOTE: TDM-201A/B provides equivalency values for boration from 2400 ppm source and a 7000 ppm source. A conservative approach is to borate the entire volume required for the condition from the 7000 ppm source once boration flow from the 2400 ppm source is terminated.

Time	Position	Applicant's Actions or Behavior
	RO/BOP	• WHEN the RWST is isolated (1/1-LCV-112D AND 1/1-LCV-112E CLOSED) per the applicable ERG, THEN initiate Emergency Boration Flow per another method of ABN-107 until the desired amount of boration volume is injected. (Reference Attachment 7 of ABN-107)

Examiner Note: The following steps are from FRP-0.1A, Response to Imminent Pressurized Thermal Shock Condition. These steps should be implemented when the Orange Path exists on Integrity as FRGs are now required to be implemented.

Operating Test :	NRC	Scenario #	2	Event #	5, 6, 7, 8, 9	Page	33	of	50

Event Description: Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer

Time	Position	Applicant's Actions or Behavior
	RO/BOP	CHECK RCS Pressure – GREATER THAN 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT) [Step 1]
		• IF total RHR pump injection flow is greater than 750 gpm, THEN return to procedure and step in effect. [Step 1 RNO]

Examiner Note: **The following steps are from FRZ-0.1A, Response to High Containment Pressure. These steps should be implemented when the Orange Path exists on Containment as FRGs are now required to be implemented. If the Orange Path exists and the crew implements FRZ-0.1A prior to verification of Containment Spray in Step 7 of EOP-0.0A then all steps of FRZ-0.1A should be performed. If the Orange Path exists and FRZ-0.1A is implemented after verification of Containment Spray in Step 7 of EOP-0.0A then the FRZ-0.1A will be exited at Step 1 RNO. All steps are included in the Scenario Guide.**

Examiner Note: **Only Train A of Containment Spray will be verified as Train B is de-energized.**

Time	Position	Applicant's Actions or Behavior
	RO/BOP	CHECK Containment Pressure – GREATER THAN 50 PSIG [Step 1]
		• IF proper Containment Spray alignment has been verified in EOP-0.0A, Reactor Trip or Safety Injection, THEN return to procedure and step in effect. [Step 1 RNO]
		VERIFY Containment Isolation Phase A – APPROPRIATE MLB LIGHT INDICATION (RED WINDOWS) [Step 2]
		VERIFY Containment Ventilation Isolation – APPROPRIATE MLB LIGHT INDICATION (GREEN WINDOWS) [Step 3]

NOTE: Component Cooling Water supply to the unit instrument air compressors isolates on a Phase B isolation signal.

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 34 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer		

Time	Position	Applicant's Actions or Behavior
	RO/BOP	CHECK if Containment Spray is required: [Step 4]
		• Containment pressure – HAS INCREASED TO GREATER THAN 18.0 PSIG [Step 4.a] • 1-ALB-2B, Window 1.8 – CS ACT Illuminated OR • 1-ALB-2B, Window 4.11 – CNTMT ISOL PHASE B ACT Illuminated OR • Containment pressure – GREATER THAN 18.0 PSIG
		• VERIFY all RCPs – STOPPED (all RCPs de-energized) [Step 4.b]
		• VERIFY Containment Isolation Phase B Valves – CLOSED [Step 4.c] • VERIFY 1-MLB-4A3 and 4B3 – ORANGE LIGHTS LIT
		• VERIFY ECA-1.1A, Loss of Emergency Coolant Recirculation is NOT in effect [Step 4.d]
		• VERIFY containment spray pumps – RUNNING [Step 4.e]
		• VERIFY spray system valve alignment – PROPER EMERGENCY ALIGNMENT PER ATTACHMENT 4 [Step 4.f]
		VERIFY Main Steamline Isolation Valves – CLOSED [Step 5]

CAUTION: At least one SG must be maintained available for RCS cooldown.

CAUTION: If all SGs are faulted, at least 100 gpm AFW flow should be maintained to each SG.

Time	Position	Applicant's Actions or Behavior
	RO/BOP	CHECK if feed flow should be isolated to any SG: [Step 6]
		• CHECK pressures in all SGs [Step 6.a] • ANY SG PRESSURE DECREASING IN AN UNCONTROLLED MANNER OR • ANY SG COMPLETELY DEPRESSURIZED

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 35 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer		

Time	Position	Applicant's Actions or Behavior
		• ISOLATE Feed flow to affected SG(s) [Step 6.b] • ISOLATE Main Feedline • ISOLATE AFW flow
		RETURN to procedure and step in effect [Step 7]
Examiner Note:		**The following steps are from EOP-0.0A, Reactor Trip or Safety Injection.**
	US	Crew will transition back to EOP-0.0A, Reactor Trip or Safety Injection, Step 1, if a direct entry to ECA-0.0A was made, or step 3 if the crew performed the first two steps of EOP-0.0A
	RO	VERIFY Reactor Trip: [Step 1]
		• VERIFY the following: [Step 1.a]
		• Reactor Trip Breakers – AT LEAST ONE OPEN AND • Neutron flux – DECREASING
		• All Control Rod Position Rod Bottom Lights – ON. (DRPI is de-energized) [Step 1.b]
	BOP	VERIFY Turbine Trip: [Step 2]
		• All HP Turbine Stop Valves – CLOSED.
	BOP	VERIFY Power to AC Safeguards Buses: [Step 3]
		• VERIFY AC Safeguards Buses – AT LEAST ONE ENERGIZED. [Step 3.a]
		• VERIFY both AC Safeguards Buses – BOTH ENERGIZED. [Step 3.b]
		• RESTORE power to de-energized AC safeguards bus per ABN-601, Response to a 138/345 KV System Malfunction or ABN-602, Response to a 6900/480 Volt System Malfunction when time permits [Step 3.b RNO b]
Examiner Note:		**The US may contact the SM to request personnel to perform appropriate ABN for loss of power, however, with only 3 personnel the crew will NOT perform the ABN.**

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 36 of 50

Event Description: Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer

Time	Position	Applicant's Actions or Behavior

Simulator Operator: **When/If contacted for extra personnel to perform the ABN-601/602 acknowledge the request as the SM.**

Time	Position	Applicant's Actions or Behavior
		CHECK SI Status: [Step 4]
		• CHECK if SI is actuated. [Step 4.a]
		• SI ACTUATED as indicated on the First Out Annunciator 1-ALB-6C
		• SI ACTUATED blue status light – ON
		• VERIFY Both Trains SI Actuated: [Step 4.b]
		• SI ACTUATED blue status light – ON NOT FLASHING.

CAUTION: A Safety Injection actuation will affect normal egress from the Containment Building. Attachment 9 of this procedure provides instructions to evacuate personnel from the Containment during a Safety Injection actuation.

NOTE: Attachment 2 is required to be completed before FRGs are implemented unless directed by this procedure.

Examiner Note: **EOP-0.0A, Attachment 2 steps performed by BOP are identified in the last section of the scenario guide.**

Time	Position	Applicant's Actions or Behavior
	US/BOP	INITIATE Proper Safeguards Equipment Operation Per Attachment 2. [Step 5]

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 37 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer		

Time	Position	Applicant's Actions or Behavior
	RO	VERIFY AFW Alignment: [Step *6]
		• MDAFW Pump 1-01 – RUNNING. [Step 6.a]
		• TDAFW Pump –RUNNING. [Step 6.b]
		• AFW total flow – GREATER THAN 460 GPM. [Step 6.c]
		• AFW valve alignment - PROPER ALIGNMENT. [Step 6.d]
	RO	VERIFY Containment Spray NOT Required: [Step *7]
		• VERIFY Containment pressure – HAS REMAINED LESS THAN 18.0 PSIG. [Step 7.a]
		• 1-ALB-2B, Window 1.8 – CS ACT - ILLUMINATED.
		• 1-ALB-2B, Window 4.11 – CNTMT ISOL PHASE B ACT - ILLUMINATED.
		• Containment pressure – GREATER THAN 18.0 PSIG.
		• PERFORM the following: [Step 7.a RNO a]
		• VERIFY Containment Spray AND Phase B Actuation initiated. IF NOT, THEN manually actuate [Step 7.a RNO a.1)]
		• VERIFY appropriate MLB indication for CNTMT SPRAY (BLUE WINDOWS) AND PHASE B (ORANGE WINDOWS) [Step 7.a RNO a.2)]
		• VERIFY Containment Spray flow [Step 7.a RNO a.3)]
		• ENSURE CHEM ADD TK DISCH VLVs – OPEN [Step 7.a RNO a.4)]
		• STOP all RCPs [Step 7.a RNO a.5)]
		• Go to Step 8 [Step 7.a RNO a.6)]

Operating Test :	NRC	Scenario #	2	Event #	5, 6, 7, 8, 9	Page	38	of	50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer								

Time	Position	Applicant's Actions or Behavior
	RO	CHECK if Main Steam lines should be ISOLATED: [Step *8]
		• VERIFY the following: [Step 8.a]
		• Containment pressure – GREATER THAN 6.0 PSIG.
		• Main Steam Line pressure – LESS THAN 610 PSIG.
		• VERIFY main steamline isolation complete: [Step 8.b]
		• Main Steam isolation valves
		• Before MSIV drippot isolation valves
	RO	CHECK RCS Temperature: [Step *9]
		• VERIFY RCS Average Temperature – STABLE AT OR TRENDING TO 557°F. [Step 9]
		• <u>IF</u> temperature less than 557°F and decreasing, <u>THEN</u> perform the following: [Step 9 RNO]
		• Stop dumping steam [Step 9 RNO a.]
		• <u>IF</u> cooldown continues, <u>THEN</u> reduce total AFW flow as necessary to minimize the cooldown: [Step 9 RNO b.] • Maintaining a minimum of 460 gpm UNTIL narrow range level greater than 43% (50% FOR ADVERSE CONTAINMENT) in at least one SG. • As necessary to maintain SG levels WHEN narrow range level greater than 43% (50% FOR ADVERSE CONTAINMENT) in at least one SG. • IF TDAFW pump is not required to maintain greater than 460 gpm flow, THEN stop TDAFW pump.
		• <u>IF</u> cooldown continues, <u>THEN</u> close main steamline isolation valves. [Step 9 RNO c.]
	RO	CHECK PRZR Valve Status: [Step 10]
		• VERIFY PRZR Safeties – CLOSED. [Step 10.a]
		• VERIFY Normal PRZR Spray Valves – CLOSED. [Step 10.b]
		• VERIFY PORVs – CLOSED. [Step 10.c]
		• VERIFY Power to at least 1 Block Valve – AVAILABLE. [Step 10.d]
		• VERIFY Block Valves – AT LEAST ONE OPEN. [Step 10.e]

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 39 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer		

Time	Position	Applicant's Actions or Behavior
	RO	CHECK if RCPs Should Be Stopped: [Step 11]
		• All RCPs are de-energized
		• GO to Step 12. [Step 11.a RNO a]
	RO/BOP	CHECK if Any Steam Generator Is Faulted: [Step 12]
		• CHECK pressures in all SGs: [Step 12.a]
		• Any Steam Generator pressure – DECREASING IN AN UNCONTROLLED MANNER.
		• Any Steam Generator pressure – COMPLETELY DEPRESSURIZED.
		• GO to Step 13. [Step 12.a RNO a]
	RO/BOP	CHECK if Steam Generator Tubes Are NOT Ruptured: [Step 13]
		• Condenser Off Gas radiation – NORMAL.
		• Main Steam Line radiation – NORMAL.
		• SG Blowdown Sample Radiation Monitor – NORMAL.
	RO/BOP	CHECK if RCS is Intact: [Step 14]
		• Containment pressure – LESS THAN 1.3 PSIG.
		• Containment recirculation sump levels – NORMAL.
		• Containment radiation levels – NORMAL GRID 4.
		• GO to EOP-1.0A, Loss of Reactor or Secondary, Step 1. [Step 14 RNO]
	US	TRANSITION to EOP-1.0A, Loss of Reactor or Secondary Coolant, Step 1.
Examiner Note:		**EOP-1.0A, Loss of Reactor or Secondary Coolant, steps begin here.**

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 40	of 50			
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel Generator in Pull-Out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on Sequencer						

Time	Position	Applicant's Actions or Behavior
		CAUTION: Following a high energy line rupture inside containment, the operator should not rely upon steam generator water level indications in any depressurized steam generators.
		NOTE: As PRZR Temperature decreases the error on indicated PRZR level will increase. Attachment 2 may be used to determine actual PRZR level.
	US/RO	CHECK If RCPs Should Be Stopped: [Step 1]
		• All RCPs are de-energized
	RO	• Go to Step 2. [Step 1.a RNO a]
	RO/BOP	CHECK if Any Steam Generator Is Faulted: [Step 2]
		• CHECK pressure in all SGs [Step 2.a]
		• Any Steam Generator pressure – DECREASING IN AN UNCONTROLLED MANNER.
		• Any Steam Generator pressure – COMPLETELY DEPRESSURIZED.
		• GO to Step 3. [Step 2.a RNO]
	US	CHECK Intact Steam Generator Levels: [Step *3]
		• Narrow range level – GREATER THAN 43% (50% FOR ADVERSE CONTAINMENT). [Step 3.a]
		• MAINTAIN total AFW flow greater than 460 GPM until narrow range level GREATER THAN 43% (50% FOR ADVERSE CONTAINMENT) in at least one intact SG. [Step 3.a RNO a]
		• Control AFW flow to maintain narrow range level between 43% (50% FOR ADVERSE CONTAINMENT) and 60%. [Step 3.b]

Operating Test :	NRC	Scenario #	2	Event #	5, 6, 7, 8, 9	Page	41	of	50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel in Pull out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on sequencer								

Time	Position	Applicant's Actions or Behavior
	US	CHECK Secondary Radiation NORMAL: [Step 4]
		• Condenser off gas radiation – NORMAL.
		• Main Steam Line radiation – NORMAL.
		• SG Blowdown Sample Radiation Monitor – NORMAL.
CAUTION: If any PRZR PORV opens because of high PRZR pressure, Step 5b should be repeated after pressure decreases to less than the PORV setpoint.		
	US	CHECK PRZR PORVs and Block Valves: [Step *5]
		• VERIFY power to block valves – AVAILABLE. [Step 5.a] Train B is de-energized and power cannot be restored.
		• VERIFY PORVs – CLOSED. [Step 5.b]
		• VERIFY Block valves – AT LEAST ONE OPEN. [Step 5.c]
	US/RO	CHECK if ECCS Flow Should Be Reduced: [Step *6]
		• Secondary heat sink: [Step 6.a]
		• Total AFW flow to intact SGs – GREATER THAN 460 GPM OR • Narrow range level in at least one intact SG – GREATER THAN 43% (50% FOR ADVERSE CONTAINMENT)
		• VERIFY RCS subcooling – GREATER THAN 25°F (55°F FOR ADVERSE CONTAINMENT). [Step 6.b]
		• GO to Step 7. OBSERVE CAUTIONS Prior to Step 7. [Step 6.b RNO b]

Operating Test :	NRC	Scenario #	2	Event #	5, 6, 7, 8, 9	Page	42	of	50

Event Description: Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel in Pull out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on sequencer

Time	Position	Applicant's Actions or Behavior
		CAUTION: If offsite power is lost after SI reset, manual action may be required to restart safeguards equipment.
		CAUTION: When time permits, Attachment 9 of EOP-0.0A, REACTOR TRIP OR SAFETY INJECTION should be performed to realign equipment after an SI signal has been reset.
	RO/BOP	RESET ESF Actuation Signals. [Step 7]
		• CHECK diesel generators – DG 1-01 RUNNING [Step 7.a]
		• PLACE DG 1-01 EMERG STOP/START handswitches in START. [Step 7.b]
	RO/BOP	RESET SI. [Step 7.c]
		• DEPRESS 1/1-SIRA, TRAIN A SI RESET pushbutton.
		• DEPRESS 1/1-SIRB, TRAIN A SI RESET pushbutton.
	RO/BOP	RESET SI Sequencers. [Step 7.d]
		• At SI Sequencer Train A Cabinet, DEPRESS SI SEQR RESET green pushbutton then PLACE ON/RESET toggle switch in RESET.
		• After ~ 2 seconds, PLACE ON/RESET toggle switch in ON.
		• At SI Sequencer Train B Cabinet, DEPRESS SI SEQR RESET green pushbutton then PLACE ON/RESET toggle switch in RESET.
		• After ~ 2 seconds, PLACE ON/RESET toggle switch in ON.
	RO/BOP	RESET Containment Isolation Phase A and Phase B. [Step 7.e]
		• DEPRESS 1/1-C1PARA, CNTMT ISOL – PHASE A RESET pushbutton.
		• DEPRESS 1/1-C1PARB, CNTMT ISOL – PHASE A RESET pushbutton.
		• DEPRESS 1/1-C1PBRA, CNTMT ISOL – PHASE B RESET pushbutton.
		• DEPRESS 1/1-C1PBRB, CNTMT ISOL – PHASE B RESET pushbutton.

Operating Test :	NRC	Scenario #	2	Event #	5, 6, 7, 8, 9	Page	43	of	50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel in Pull out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on sequencer								

Time	Position	Applicant's Actions or Behavior
	RO/BOP	RESET Containment Spray Signal. [Step 7.f]
		• DEPRESS 1/1-CSRA, TRAIN A CS RESET pushbutton.
		• DEPRESS 1/1-CSRB, TRAIN B CS RESET pushbutton.
		CAUTION: RCS pressure should be monitored. If RCS pressure decreases in an uncontrolled manner to less than 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT) the RHR pumps must be manually restarted to supply water to the RCS.
	US	CHECK If RHR Pumps Should Be Stopped: [Step *8]
		• CHECK RCS pressure: [Step 8.a]
	RO/BOP	• RCS pressure – GREATER THAN 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT). [Step 8.a.1)]
		• GO to Step 10. [Step 8.a.1) RNO 1)]
	US	CHECK If Diesel Generators Should Be Stopped: [Step *10]
	RO/BOP	• VERIFY AC Safeguards Buses ENERGIZED by Offsite Power. [Step 10.a]
	RO/BOP	• Restore offsite power to AC safeguards busses per ABN-601, RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION or ABN-602, RESPONSE TO A 6900/480 VOLT SYSTEM MALFUNCTION. [Step 10.a RNO a]
		• STOP any unloaded diesel generator by placing DG EMER STOP/START handswitch in STOP. [Step 10.b] (DG 1-01 is running loaded and DG 1-02 is in PULL-OUT)
		NOTE: Verification of at least one flowpath from a RHR pump to the RCS via a SI pump or CCP is sufficient to verify cold leg recirculation capability.

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 44 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel in Pull out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on sequencer		

Time	Position	Applicant's Actions or Behavior
Examiner Note:		**Emergency Recirculation capability will be verified for Train A as Train B is de-energized.**
	US	INITIATE Evaluation of Plant Status. [Step 11]
	BOP	• VERIFY Cold Leg Recirculation capability: [Step 11.a]
		• VERIFY the following conditions for the train related RHR pump(s): [Step 11.a.1)]
		• Train A RHR Pump – AVAILABLE.
		• CCW to Train A RHR Pump – AVAILABLE.
		• 1/1-8811A, CNTMT SMP TO RHRP 1 SUCT ISOL VLV AVAILABLE.
		• VERIFY RHR valve(s) that supply SI pumps and CCPs – AVAILABLE [Step 11.a.2)]
		• 1/1-8804A, RHRP 1 TO CCP SUCT VLV – AVAILABLE.
		• 1/1-8804B, RHRP 2 TO SIP SUCT VLV – NOT AVAILABLE.
		• Perform the following: [Step 11.a.2) RNO 2)]
		• IF 1/1-8804A OR 1/1-8804B, NOT available, THEN verify at least one SI ← → CHRG SUCT HDR XTIE VLV – AVAILABLE: [Step 11.a.2) RNO 2)A)] • 1/1-8807A OR • 1/1-8807B
	RO/BOP	• CHECK Auxiliary Building and Safeguards Building radiation – NORMAL: [Step 11.b]
		• CHECK PC-11 monitors – NORMAL OR • Notify Radiation Protection to take local Radiation Surveys.
	US	• NOTIFY Chemistry to obtain RCS samples to assist in determining extent of the accident. [Step 11.c]
		• EVALUATE plant equipment: [Step 11.d]
	US	• CONSULT Plant Staff to determine equipment that should be available or started to assist in recovery

Operating Test : NRC	Scenario # 2	Event # 5, 6, 7, 8, 9	Page 45 of 50
Event Description:	Loss of Offsite Power, Train A Diesel Generator Start Failure, Train B Diesel in Pull out, Pressurizer Steam Space Sample Valve Failure, LBLOCA, RHR Pump 1-01 fails to start on sequencer		

Time	Position	Applicant's Actions or Behavior
	US	CHECK if RCS Cooldown and Depressurization Is Required: [Step 12]
	RO/BOP	• RCS pressure – GREATER THAN 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT). [Step 12.a]
	US	• IF RHR pump flow greater than 750 gpm, THEN go to Step 13 [Step 12.a RNO a]
	US	CHECK if transfer to Cold Leg Recirculation is required: [Step 13]
		• RWST level – LESS THAN LO-LO LEVEL [Step 13.a]
		• RETURN to Step 11. OBSERVE NOTE PRIOR TO STEP 11 [Step 13.a RNO a]
		• Go To EOS-1.3A, Transfer to Cold Leg Recirculation, Step 1 [Step 13.a]
When conditions are met to transfer to EOS-1.3A, Transfer to Cold Leg Recirculation, TERMINATE the scenario		

Operating Test : NRC	Scenario # 2	Event # ATT 2	Page 46 of 50
Event Description: EOP-0.0A Attachment 2			

Time	Position	Applicant's Actions or Behavior
Examiner Note:		**These steps are performed by the BOP per EOP-0.0A, Attachment 2.**
		CAUTION: If during performance of this procedure the SI sequencer fails to complete its sequence, Attachment 3 may be used to ensure proper equipment operation for major equipment.
	BOP	VERIFY SSW Alignment: [Step 1]
		• VERIFY SSW Pump 1-01 – RUNNING. [Step 1.a]
		• VERIFY EDG Cooler SSW return flow. [Step 1.b]
	BOP	VERIFY Safety Injection Pump 1-01 – RUNNING. [Step 2]
	BOP	VERIFY Containment Isolation Phase A – APPROPRIATE MLB LIGHT INDICATION (RED WINDOWS). [Step 3]
	BOP	VERIFY Containment Ventilation Isolation – APPROPRIATE MLB LIGHT INDICATION (GREEN WINDOWS). [Step 4]
	BOP	VERIFY CCW Pump 1-01 – RUNNING. [Step 5]
CRITICAL TASK STATEMENT		**Manually start RHR Pump 1-01 in accordance with EOP-0.0A, Attachment 2 or EOP-1.0A, Attachment 1A prior to exiting EOP-1.0A, Loss of Reactor or Secondary Coolant.**
	BOP	VERIFY RHR Pumps – RUNNING. [Step 6]
		• Recognizes RHR Pump 1-01 did not start on the SI and manually starts RHR Pump 1-01

Operating Test :	NRC	Scenario #	2	Event #	ATT 2	Page	47	of	50
Event Description:	EOP-0.0A Attachment 2								

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY Proper CVCS Alignment: [Step 7]
		• VERIFY CCP 1-01 – RUNNING. [Step 7.a]
		• VERIFY Letdown Relief Valve Isolation: [Step 7.b]
		• Letdown Orifice Isolation Valves – CLOSED. [Step 7.b.1)]
		• Letdown Isolation Valves 1/1-LCV-459 & 1/1-LCV-460 – CLOSED. [Step 7.b.2)]
	BOP	VERIFY ECCS flow: [Step 8]
		• CCP SI flow indicator – CHECK FOR FLOW. [Step 8.a]
		• RCS pressure – LESS THAN 1700 PSIG (1800 PSIG FOR ADVERSE CONTAINMENT). [Step 8.b]
		• SIP discharge flow indicator – CHECK FOR FLOW. [Step 8.c]
		• RCS pressure – LESS THAN 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT). [Step 8.d]
		• RHR TO CL INJ flow indicators – CHECK FOR FLOW. [Step 8.e]
	BOP	VERIFY Feedwater Isolation Complete: [Step 9]
		• Feedwater Isolation Valves – CLOSED.
		• Feedwater Isolation Bypass Valves – CLOSED.
		• Feedwater Bypass Control Valves – CLOSED.
		• Feedwater Control Valves – CLOSED.
	BOP	VERIFY Diesel Generator 1-01 – RUNNING. [Step 10]
	BOP	VERIFY Monitor Lights for SI Load Shedding on 1-MLB-9 and 1-MLB-10 – LIT. [Step 11]

NOTE: The MLB indication for SI alignment includes components which may be in a different alignment to support unit conditions. MSIVs, MSLs BEF MSIV D/POT ISOL, TDAFWP STEAM SUPPLIES, TDAFWP RUN, MDAFWP FLO CTRL VLVs and TDAFWP FLO CTRL VLVs may be exceptions to the expected MLB indication.

Operating Test : NRC	Scenario # 2	Event # ATT 2	Page 48 of 50
Event Description: EOP-0.0A Attachment 2			

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY Proper SI alignment – PROPER MLB LIGHT INDICATION. [Step 12]

NOTE: Any previously removed missile shield(s) that affects the Control Room, Auxiliary, Safeguards or Fuel Building pressure boundary is required to be restored upon initiation of a Safety Injection Signal.

NOTE: When the SI sequencer has timed out, the Reactor Makeup Water Pump with its handswitch in Auto will restart.

BOP	VERIFY Components on Table 1 are properly aligned. [Step 13]			
	Location	Equipment	Description	Condition
	CB-03	X-HS-5534	H2 PRG SPLY FN 4	STOPPED
	CB-03	X-HS-5532	H2 PRG SPLY FN 3	STOPPED
	CB-04	1/1-8716A	RHRP 1 XTIE VLV	OPEN
	CB-04	1/1-8716B	RHRP 2 XTIE VLV	OPEN
	CB-06	1/1-8153	XS LTDN ISOL VLV	CLOSED
	CB-06	1/1-8154	XS LTDN ISOL VLV	CLOSED
	CB-07	1/1-RTBAL	RX TRIP BKR	OPEN
	CB-07	1/1-RTBBL	RX TRIP BKR	OPEN
	CB-07	1/1-BBAL	RX TRIP BYP BKR	OPEN/DEENERGIZED
	CB-07	1/1-BBBL	RX TRIP BYP BKR	OPEN/DEENERGIZED
	CB-08	1-HS-2397A	SG 1 BLDN HELB ISOL VLV	CLOSED
	CB-08	1-HS-2398A	SG 2 BLDN HELB ISOL VLV	CLOSED
	CB-08	1-HS-2399A	SG 3 BLDN HELB ISOL VLV	CLOSED
	CB-08	1-HS-2400A	SG 4 BLDN HELB ISOL VLV	CLOSED
	CB-08	1-HS-2111C	FWPT A TRIP	TRIPPED
	CB-08	1-HS-2112C	FWPT B TRIP	TRIPPED
	CB-09	1-HS-2490	CNDS XFER PUMP	STOPPED (MCC deenergized on SI)
	CV-01	X-HS-6181	PRI PLT SPLY FN 17 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6188	PRI PLT SPLY FN 18 & INTK DMPR	STOPPED/DEENERGIZED

Operating Test : NRC	Scenario # 2	Event # ATT 2	Page 49 of 50
Event Description: EOP-0.0A Attachment 2			

Time	Position	Applicant's Actions or Behavior		
	CV-01	X-HS-6195	PRI PLT SPLY FN 19 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6202	PRI PLT SPLY FN 20 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6209	PRI PLT SPLY FN 21 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6216	PRI PLT SPLY FN 22 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6223	PRI PLT SPLY FN 23 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6230	PRI PLT SPLY FN 24 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-3631	UPS & DISTR RM A/C FN 1 & BSTR FN 42	STARTED
	CV-01	X-HS-3632	UPS & DISTR RM A/C FN 2 & BSTR FN 43	STARTED
	CV-01	1-HS-5600	ELEC AREA EXH FN 1	STOPPED/DEENERGIZED
	CV-01	1-HS-5601	ELEC AREA EXH FN 2	STOPPED/DEENERGIZED
	CV-01	1-HS-5602	MS & FW PIPE AREA EXH FN 3 & EXH DMPR	STOPPED/DEENERGIZED
	CV-01	1-HS-5603	MS & FW PIPE AREA EXH FN 4 & EXH DMPR	STOPPED/DEENERGIZED
	CV-01	1-HS-5618	MS & FW PIPE AREA SPLY FN 17	STOPPED/DEENERGIZED
	CV-01	1-HS-5620	MS & FW PIPE AREA SPLY FN 18	STOPPED/DEENERGIZED
	CV-03	X-HS-5855	CR EXH FN 1	STOPPED/DEENERGIZED
	CV-03	X-HS-5856	CR EXH FN 2	STOPPED/DEENERGIZED
	CV-03	X-HS-5731	SFP EXH FN 33	STOPPED/DEENERGIZED
	CV-03	X-HS-5733	SFP EXH FN 34	STOPPED/DEENERGIZED
	CV-03	X-HS-5727	SFP EXH FN 35	STOPPED/DEENERGIZED
	CV-03	X-HS-5729	SFP EXH FN 36	STOPPED/DEENERGIZED
BOP	NOTIFY Unit Supervisor attachment instructions complete AND to implement FRGs as required.			

```
;CPNPP 2017 NRC Scenario 2
;Initial Conditions

;Setup: MDAFWP 1-02 in Pull-Out - Breaker Deenergized
IRF FWR021 f:0

;DG 1-01 Fails to Auto Start
IMF EG15A f:1

;PSS Valve MLB Lights
IOR LOANMLB1A2_1 f:1
IOR LOANMLB1B2_1 f:1

;Main Turbine Runback Failure (All)
IMF TC09I f:1

;Loss of 1PC1
IMF ED07A f:1 k:1

;Transfer 1PC1 to alternate
IRF EDR01 f:0 k:10

;SSWP 2 Trip
IMF SW01B f:1 k:2

;VCT Lv1 112 fail low
IMF CV16A f:0 k:3

;HDP 1-02 Trip, Rods fail to step in Auto
IMF FW14B f:1 k:4
IMF RD15A f:1 k:4

;LOOP
IMF ED01 f:1 k:5

;RCS Loop 1 LBLOCA on DG 1-01 Emerg Start
{DIEG1DG1E.Value=4} IMF RC08A2 f:1 d:120

;RHR Pump 1-01 Fails to Sequence on SI
IMF RH01C f:1

;Allow PSS Valves to close
aet ET4165
aet ET4167
```

GUARDED EQUIPMENT MANAGEMENT (GEM) SIGN POSTING LOG

REASON FOR POSTING MDAFW Pump 1-02

Component to be Posted	Nomenclature	Posting Installed	Posting Checked	Posting Removed
		Initial	Initial	Initial
1-HS- 2450A	MDAFW Pump 1-01	OPR	BOF	

Authorized By: Unit Superviser Date: Today Posting Removal Authorized By:________ Date:________

Open Narrative Log Entry Entered ☒ Open Narrative Log Entry Closed ☐

Comments:________

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT COMMON

ABNORMAL CONDITIONS PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS Mm / 2day LATEST PCN/EFFECTIVE DATE PCN-10 / 10/19/16 1200

LEVEL OF USE:
CONTINUOUS USE

QUALITY RELATED

ACTS OF NATURE

PROCEDURE NO. ABN-907
REVISION NO. 15

EFFECTIVE DATE: 2/11/15 1200

PREPARED BY (Print): Les Meller Ext: 6009

TECHNICAL REVIEW BY (Print): Dillon Richey Ext: 6769

APPROVED BY: B. St.Louis for M.R. Smith Date: 1/18/15
DIRECTOR, OPERATIONS

TABLE OF CONTENTS

1.0 APPLICABILITY

This procedure describes the actions to be taken in the event any of the following acts of nature occur during any mode of operation.

This procedure applies to Unit 1 and Unit 2 operations.

Operation/manipulation of systems, equipment or components common to BOTH units shall be controlled by Unit 1 unless otherwise directed by the Shift Manager.

- Earthquake (Section 2.0)
- Flooding (Section 3.0)
- Abnormal Decrease in Squaw Creek Reservoir Level (Section 4.0)
- Severe Weather (Section 5.0)

5.0 SEVERE WEATHER

5.1 Symptoms

a. Annunciator Alarms

None

> NOTE:
> - The National Weather Service (NWS) has a continuous radio broadcast service of weather conditions in the Dallas-Ft. Worth area. A receiver capable of receiving and decoding the NWS alert tone for severe weather notifications is monitored in the Alternate Access Point for the issuance or cancellation of Severe Thunderstorm and Tornado Watches. Security personnel on duty in the Alternate Access Point will keep the Control Room informed of all watches or warnings issued or canceled by the NWS. Visual observations will be made by Security Officers and Safety Services personnel during the performance of their normal duties when a watch has been issued. The Control Room will be kept informed of visual observations regarding weather conditions by radio or telephone. Plant Equipment Operators are trained as SKYWARN spotters and may be utilized to determine weather severity.
> - A warning means a severe thunderstorm or tornado has been sighted or detected by radar and may be approaching. A watch means meteorological conditions are favorable for the formation of a severe thunderstorm or tornado.
> - Escalating Probabilistic Risk Assessment (PRA) category/level is a consideration if severe weather may impact switchyard availability or off-site power is already impaired (i.e. currently in a LCOAR).
> - Safety-Security interface controls per STA-919 are implemented as needed during severe weather conditions.

b. Plant Indications

- A Severe Thunderstorm or Tornado Warning has been issued for the CPNPP area as reported by Security or per the National Weather Service (NWS) at:

  (214) 787-1111 (recording)
  *(817) 831-1581 (unlisted)
  *(817) 831-1157 (Admin requests/info-unlisted)

  * These numbers are direct to the Forecast Office and should not be used except during severe weather.

STEP CONTINUED NEXT PAGE

5.1 b.
- Severe weather directly observed and reported by plant personnel.(i.e. cloud to ground lightning nearby, hail, high winds)
- A severe Thunderstorm or Tornado Watch or Warning has been issued for the CPNPP area.
- Indications of severe weather from the system radar display (See Attachment 4).

5.2 Automatic Actions

None

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

CAUTION: Lightning may cause spurious HIGH FLUX AT SHUTDOWN radiation monitor alarms. The High Flux at Shutdown alarm may be blocked during severe weather with lightning to avoid spurious Containment Evacuation alarms due to Source Range spikes. The High Flux at Shutdown alarm is not required by Technical Specifications. However, the alarm is required to be in service during Core Alterations to satisfy Licensing Basis Document Commitments. The time alarms are blocked should be limited to the duration of severe weather in the vicinity.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 1 VERIFY NO severe weather in vicinity of CPNPP accompanied by lightning.	At NIS Cabinets on Source Range Drawers PLACE the HIGH FLUX AT SHUTDOWN switches in BLOCK, IF desired. IF alarms are received coincident to a nearby lightning strike, THEN DOCUMENT the specific alarms received on a Condition Report when time permits. IF 25 KV Loop affected, THEN REFER to ABN-613 for actions.

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

☑ 2 DETERMINE PRA risk escalation from Table 1.

Table 1: PRA Escalation Determination

	CPNPP and Somervell County (1, 2) Severe Thunderstorm (STS) OR Tornado Watch	CPNPP and Somervell County (1, 2) Severe Thunderstorm (STS) OR Tornado WARNING OR STS or Tornado observed on site	"General Area" (see Att. 4) – area likely to affect offsite power source (1) Severe Thunderstorm (STS) OR Tornado Watch	General Area" (see Att. 4) – area likely to affect offsite power source (1) Severe Thunderstorm (STS) OR Tornado WARNING
One Offsite Source inoperable (in an active LCOAR) N/A	ESCALATE PRA risk level*	ESCALATE PRA risk level*	ESCALATE PRA risk level*	ESCALATE PRA risk level*
OPT-215 Offsite sources Operable	MONITOR AND EVALUATE**	ESCALATE PRA risk level	MONITOR AND EVALUATE**	MONITOR AND EVALUATE**
Information from TGM/QSE indicates grid threatened by severe weather N/A	ESCALATE PRA risk level*	ESCALATE PRA risk level*	ESCALATE PRA risk level*	ESCALATE PRA risk level*

(1) In addition, IF winds are expected to exceed 80 mph, THEN ESCALATE PRA risk level.
(2) CPNPP area includes southern portion of Hood County.

* This is accomplished by adjusting / increasing the Loss of Offsite Power initiating event frequency by a factor of about 10 for Equipment Out of Service (EOOS) Program or increasing the risk color one level for the matrix based on STI-604.02.

** The "MONITOR AND EVALUATE" activity described in Table 1 is meant to use all available means to monitor the existing and projected weather conditions and evaluate, using conservative decision making, the threat the weather conditions present to the continued availability and reliability of offsite power. If such a threat is determined to exist, then, the PRA risk level should be escalated

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☑ 3 NOTIFY the Work Control Center Work Week Coordinator of the severe weather condition and to evaluate risk assessment impact per STA-604 AND STI-604.02 AND SUSPEND, COMPLETE, OR POSTPONE work on systems that would be necessary to mitigate a Loss of Offsite Power Event OR might impact continued power operations.	

NOTE: Exterior doors, especially the HP Turbine Dog House doors, can be a significant source of water intrusion AND should be closed expeditiously.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☑ 4 CONSULT with Shift Manager to determine actions of Attachment 2 to be performed while CONTINUING this procedure.	
5 DETERMINE action steps to be taken for event in progress (CPNPP area):	IF severe weather is forecast to be moving in direction of CPNPP OR Somervell County, THEN INCREASE weather monitoring frequency. RETURN to this procedure if a watch or warning is issued.
☐ a. Tornado OR Severe Thunderstorm WARNING in effect - GO TO STEP 6.	
☐ b. Tornado OR Severe Thunderstorm WATCH in effect - GO TO STEP 17.	
☐ 6 Tornado WARNING - IN EFFECT	GO TO Step 10

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 7 PLACE the following handswitches in - OPEN ☐ • X-HS-5825D, CR A/C MU AIR SPLY DMPR 17 ☐ • X-HS-5828D, CR A/C MU AIR SPLY DMPR 20	
☐ 8 ALL of Standard Clearance #30 - previously hung under "WATCH" • GO TO Step 10.	GO TO Step 9.
☐ 9 PLACE CR HVAC in EMERGENCY RECIRC per Attachment 5.	
☐ 10 VERIFY Missile Shields per LCOAR - INSTALLED AS REQUIRED ☐ a. ENSURE at least one swinging door (Su-35G, UNIT u CONTAINMENT ACCESS DOOR) OPEN if either the equipment hatch or PAL door is closed.	ENSURE missile shields installed OR requirements met.

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
11 Notify Personnel	
☐ • MAKE applicable Plant wide announcement on plant ALL-PAGE AND plant radio system. EXAMPLE: THUNDERSTORM: ATTENTION ALL PERSONNEL. A SEVERE THUNDERSTORM WARNING IS IN EFFECT. SEEK SHELTER IN A PERMANENT BUILDING AND PROTECT YOURSELF. TORNADO: ATTENTION ALL PERSONNEL. A TORNADO WARNING IS IN EFFECT. SEEK SHELTER IN THE DESIGNATED SHELTER AREA WITHIN THE BUILDING AND PROTECT YOURSELF.	
☐ • NOTIFY Security of potential loss of security equipment AND the need to implement STA-919 controls, if required.	

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE: Severe weather may affect fuel handling activities due to loss of power to equipment, erratic nuclear instrument indication from electrical activity, or development of excessive differential pressure between Containment and the Fuel Building (may affect SFP levels).

☐ 12 PERFORM the following:

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
a. VERIFY NO Fuel movement - IN PROGRESS.	a. CONSIDER performing all OR selected steps as follows: • PLACE fuel assembly(s) in a safe position. • ENSURE fuel transfer cart is in Fuel Building AND VERIFY/CLOSE uSF-0001, UNIT 1(2) FUEL TRANSFER TUBE GATE VLV • SUSPEND all fuel handling activities until weather warning is cleared.
b. VERIFY Spent Fuel Cooling - IN SERVICE	b. RESTORE per ABN-909.

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

☐ 13 CHECK expected intensity AND duration of expected rainfall to determine if flooding may also be a concern:

- CONTACT National Weather Service
  (817) 831-1581 (unlisted)
  (817) 429-2631 (unlisted)
- CONTACT TGM -Transmission Grid Controller.
- Reports from plant personnel observing weather.
- CONTACT EP Manager for Squaw Creek Dam Emergency Plan requirements.

☐ 14 REFER TO EPP-201.

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 15 WHEN the threat of severe weather is passed by the cancellation of appropriate Watch/Warning or observation that severe weather has passed the plant site and is moving away (by spotter observation or computer data), normal work activities may be resumed. THEN MAKE all-clear plant wide announcement on plant ALL-PAGE AND plant radio system EXAMPLE: ATTENTION ALL PERSONNEL. THE SEVERE WEATHER HAS PASSED. RESUME NORMAL DUTIES. REPORT ANY STORM DAMAGE TO THE CONTROL ROOM.	
☐ 16 GO TO Step 20	
☐ 17 CHECK CPNPP/Somervell County - UNDER A TORNADO WATCH	GO TO Step 19.

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
[C] 18 PREPARE plant for tornadic activity as follows:	
☐ a. VERIFY BOTH trains of CR HVAC are capable of being placed in Emergency Recirc AND ENSURE ALL CRAC units are capable of operation.	a. PREPARE AND HANG a clearance on components NOT capable of being placed in Emergency Recirc OR are NOT capable of operation using Attachment 1 as a guide. -OR- HANG Standard Clearance #30 for ALL components.
b. WHEN a Tornado WARNING is in effect OR tornado activity is observed in the vicinity of CPNPP, THEN:	
1) PLACE the following handswitches in - OPEN	
☐ • X-HS-5825D, CR A/C MU AIR SPLY DMPR 17	
☐ • X-HS-5828D, CR A/C MU AIR SPLY DMPR 20	
☐ 2) PLACE CR HVAC in EMERGENCY RECIRC per Attachment 5.	
☐ c. VERIFY missile shields per LCOAR - INSTALLED AS REQUIRED	c. ENSURE missile shields installed OR requirements met.

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
18 ☐ d. DISPATCH Operators AND Maintenance to perform the following: • REMOVE all missile hazards from switchyard. • REMOVE all non-essential vehicles AND portable equipment from switchyard. • ENSURE all switchyard building doors CLOSED AND LATCHED.	
☐ e. NOTIFY Security of potential loss of security equipment AND the need to implement STA-919 controls, if required.	
☐ f. GO TO Step 20.	
☐ 19 High wind velocity - EXPECTED	GO TO Step 20.
a. DISPATCH operator(s) AND Maintenance to ensure all missile hazards and portable equipment secured OR removed from switchyard. AND All switchyard building doors CLOSED AND LATCHED.	
☐ 20 MAINTAIN increased weather monitoring frequency until severe thunderstorm OR tornado watch is canceled. GO TO Step 1 if watch upgraded to warning.	

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

21 WHEN severe weather watch is canceled, THEN PERFORM following:

- ☐ a. IF Clearance issued, THEN REMOVE clearance.
- b. PLACE the following handswitches in - AUTO
  - ☐ • X-HS-5825D, CR A/C MU AIR SPLY DMPR 17
  - ☐ • X-HS-5828D, CR A/C MU AIR SPLY DMPR 20
- ☐ c. RESTORE Control Room Ventilation to normal per SOP-802.
- ☐ d. INFORM any group(s) whose activities were curtailed due to severe weather.

"Step continued next page"

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 21 e. IF blocked in Step 1, THEN PLACE HIGH FLUX AT SHUTDOWN switches in NORMAL.	
☐ f. EVALUATE any PRA changes made.	
☐ g. IF wind gusts reached ≥50 mph, THEN visually INSPECT MS/FW HELB dampers to ensure OPEN AND UNDAMAGED. • CP1-VADPSI-01, MAIN STEAM & FEEDWATER PIPE VENTILATION SPLY ISOLATION DAMPER 1-01 • CP1-VADPSI-02, MAIN STEAM & FEEDWATER PIPE VENTILATION RET ISOLATION DAMPER 1-02 • CP2-VADPSI-01, MS/FW PIPE PENETRATION AREA VENTILATION SUPPLY ISOLATION DAMPER 2-01 • CP2-VADPSI-02, MS/FW PIPE PENETRATION AREA VENTILATION EXHAUST ISOLATION DAMPER 2-02	

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

☐ 22 REFER to STA-501

CAUTION: Tornado vents, doors or dampers being opened may violate ventilation pressure boundaries for the Auxiliary Building, Safeguards Building, and the Control Room.

☐ 23 VERIFY NONE of the following occurred: • Wind speed in excess of 80 MPH • Damage to structures OR equipment caused by the severe weather. • Severe weather conditions required any offsite notification.	PERFORM Attachment 3 as applicable:

5.3 Operator Actions

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

NOTE:
- The Technical Specifications for Dry Cask Storage which are under 10CFR72 are not waved by a declaration of 10CFR50.54(x), and are required to be complied with.
- In the event of a loss of communications between the ISFSI and the Plant Computer, the subsequent daily operator inspections of the cask air inlet vents for blockage shall continue in accordance with OPT-102A. In the event that the daily inspections cannot be routinely performed, notify the Duty Manager and the Regulatory Affairs Manager, and request an Engineering Evaluation.
- Refer to the CoC Technical Specification LCO 3.1.2 for required action times if the vents are blocked. Note that the percentage of blockage is computed separately for the 4 inlet vents and the 4 outlet vents, and not from the combination of the 8 vents.

ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
☐ 24 IF severe weather reached the site, THEN DISPATCH Operators AND the PROMPT Team to the ISFSI to locally verify NO blockage of the air vents. AND NO obvious damage to: • RTD conduit • MUX panels • the Electrical Equipment Building including contents.	PERFORM the following: a. REMOVE debris from air vents. b. REPORT any obvious OR suspected damage AND air vent blockage to Shift Manager AND Operations Management. c. NOTIFY Duty Manager d. NOTIFY Radiation Protection to survey the reachable areas of HI-STORMs with more than 2 inlet vents OR more than 2 outlet vents blocked for increased dose AND resurveyed every 12 hours thereafter until directed by the Duty Manager to stop.

END OF SECTION

ATTACHMENT 4
PAGE 1 OF 2

WEATHER RADAR INDICATIONS

Weather Radar Summary
Both radars are set on a background of north central Texas, including county lines.

NOWRAD- Fixed graphic display on which images consisting of echo top heights, cell movement indicators, tornado and severe thunderstorm watch boxes, and the NEXRAD Storm Table information are overlaid onto the mosaic radar imagery.

NEXRAD- Dynamic graphic display consisting of the latest 5 radar images downloaded. This should be the most current radar display available. The frames will automatically update when new data is available. No information other than base reflectivity (precipitation intensity) is shown.

Radar Status Indicators: White "+" - radar site functioning and contributing data
Pink square - radar site is not being is not being displayed on the image.
"NE"- radar sees "No echos"
"NA"- radar not available. Note: some radars are cycled on as needed.

Precipitation Intensity: Light rain - Light greens
Moderate rain - Dark greens and yellows
Heavy rain - Orange and reds
Intense rains - Purple
Light snow - Light blues
Moderate snow - Blues
Heavy snow - Dark blues
Light mixed - Light pink
Moderate mixed - Pinks
Heavy mixed - Dark pinks

NEXRAD Storm Table: Cell movements are in knots, direction indicated by white arrows.
Echo tops are in hundreds of feet.
Severe Thunderstorm Watch: Blue box
Tornado Watch: Red box
(Watches are issued by the Storm Prediction Center in Norman, Oklahoma. Warnings are issued by NWS Ft. Worth.)
MESO *(Mesocyclone)*: The NEXRAD algorithms detect a three dimensional rotating section of a storm that is an indicator of severe weather.
TVS *(Tornadic vortex signature)*: Potential tornadic activity is detected by the NEXRAD algorithms within the mesocyclone.
HAIL *(Hail)*: The NEXRAD algorithms are detecting the probability of hail within the storm.
HOOK *(Hook Echo)*: The radar observer is detecting a hook echo which is an indicator for potential tornadoes.

CPNPP ABNORMAL CONDITIONS PROCEDURES MANUAL	UNIT COMMON	PROCEDURE NO. ABN-907
ACTS OF NATURE	REVISION NO. 15 CONTINUOUS USE	PAGE 50 OF 52

ATTACHMENT 4
PAGE 2 OF 2

WEATHER RADAR INDICATIONS

National Lightning Detection Network

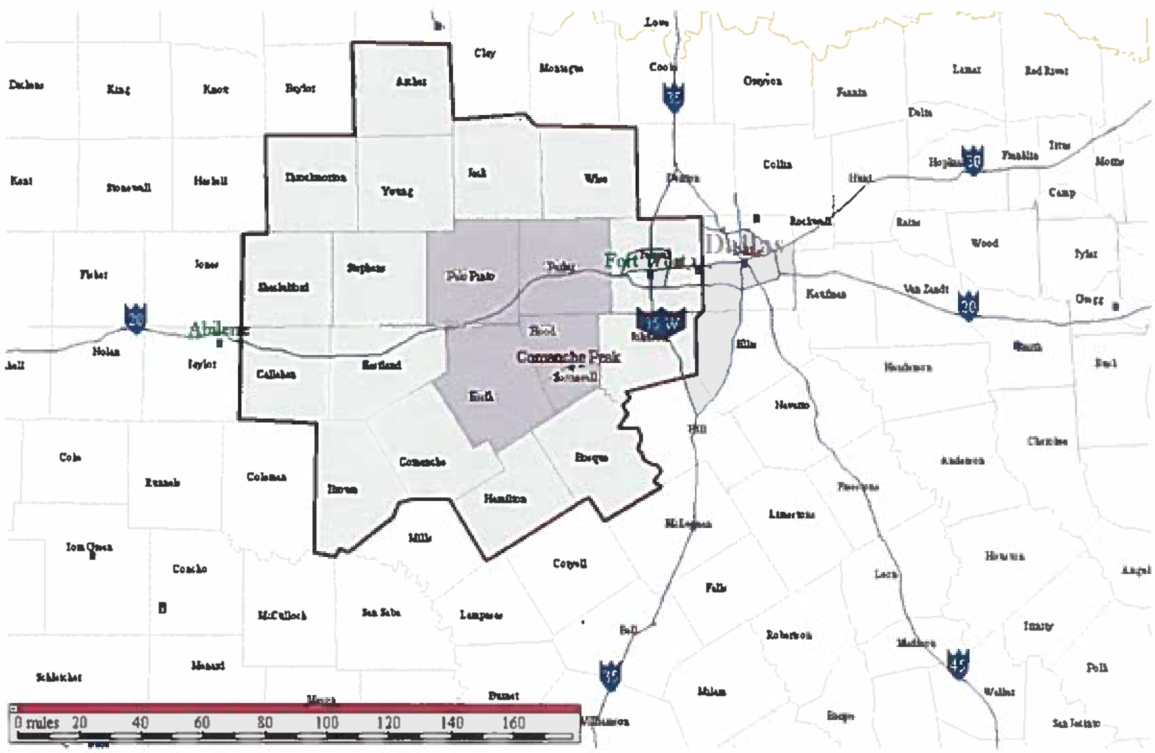
Computer displays cloud to ground strikes in total number per hour and an hourly rate (5 minute number X 12), for the system (Total), and for the displayed map region (Region). Strikes are displayed in 20 minute color increments. A severe storm will have >200 strikes per hour. Decreasing lightning intensity can indicate a storm is losing intensity.

Severe weather (Watch *or* Warning) in the CPNPP **Immediate Area** will require response or determination that no threat exists to CPNPP.

Severe weather (Watch *or* Warning) in the CPNPP **General Area** should be monitored at least hourly.

Immediate area is the area in **Orange.** (dark gray on black & white copies)
Counties of Somervell, Hood, Erath, Parker, & Palo Pinto

General Area is the area in **Yellow** and **Orange.**(light gray on black & white copies or black outline)
Counties of Archer, Bosque, Brown, Callahan, Comanche, Eastland, Hamilton, Jack, Johnson, Shakelford, Stephens, Tarrant, Throckmorton, Wise, & Young, and includes the CPNPP Immediate Area.



Attachment 4

ATTACHMENT 2
PAGE 1 OF 2

SEVERE WEATHER PREPARATIONS

CAUTION: The following actions should be performed only if weather conditions allow safe performance.

NOTE: The following should be performed based on supervisory judgement (i.e. available time and resources).

☑ 1. ENSURE ALL TB 830 Equipment Access Hatches - INSTALLED.

☑ 2. ENSURE Yard 810 Condenser Access Hatches - INSTALLED.

☑ 3. ENSURE ALL building exterior doors - CLOSED.

☑ 4. ENSURE the following exterior items properly stored, secured, OR tied down (including items on building roofs):

- Cranes
- Gas bottles
- Ladders
- Scaffolding and construction materials
- Tools
- Barrels
- Boxes
- Any other potential missiles

☑ 5. ENSURE radiological releases secured.

☑ 6. ENSURE DWST - FULL

☑ 7. CHECK availability of Diesel Fire pumps.

☑ 8. ENSURE sufficient supply of fuel oil.

☑ 9. CONSIDER stationing personnel at SWIS AND other structures with operating equipment that may be inaccessible during severe weather. CONSIDER potential impact of excessive debris on screens.

ATTACHMENT 2
PAGE 2 OF 2

SEVERE WEATHER PREPARATIONS

☑ 10. CONSIDER suspending ALL outside work (Perimeter NEO watch, etc.)

☑ 11. CONSIDER Escalating PRA risk level if severe weather may impact switchyard availability or off-site power is already impaired (i.e. currently in a LCOAR).

☑ 12. REVIEW ABN-601, ABN-602, EOP-0.0A/B, AND ECA-0.0A/B for equipment availability AND operator preparedness.

☑ 13. ENSURE Security is made aware of the potential to implement STA-919 controls.

Reactivity Briefing Sheet for Stable Operation

MOL PROJECTIONS - SIMULATOR USE ONLY

Valid for approximately 7 days.

Calculations based on core design values, and assume:

Burnup =	**12000.0**	MWD/MTU
	270.8	EFPD
Power =	**100**	RTP
Boron =	**775**	ppm
B10 Conc =	**0.183400**	w/o
Control Bank D =	**215**	steps

Burnup in the MOL range

NOTE: Re-create the Briefing Sheet if current values significantly differ from assumed inputs.

Reactivity affects of Control Bank D

HFP Diff Worth @ 215.0 steps = **-1.6** pcm / step

HFP Integral Rod Worth for CBD Step Positions:

Steps	pcm	Steps	pcm	Steps	pcm	Steps	pcm
225	0.0	218	-5.7	211	-17.7	200	-48.5
224	0.0	217	-7.0	210	-20.0	195	-65.6
223	-1.4	216	-8.4	209	-22.3	190	-83.6
222	-2.0	215	-10.0	208	-24.9	185	-102.0
221	-2.7	214	-11.7	207	-27.5	180	-120.4
220	-3.6	213	-13.6	206	-30.3	175	-138.7
219	-4.6	212	-15.6	205	-33.1	170	-156.7

Reactivity affects of Boron (Assuming BAT concentration of 7447.0 ppm)

HFP Diff Boron Worth @ 775 ppm = **-7.8** pcm / ppm

1-FK-110 Pot Setting for Blended Flow @ 775 ppm = **2.34** (90 gpm Total Flow)

1-FK-110 Pot Setting for Blended Flow @ 775 ppm = **3.30** (127 gpm Total Flow)

Reactivity affects of Power

Power Coefficient of Reactivity = **-16.0** pcm / % RTP

Dilution to equal 1% Power Increase = **180.5** gallons RMUW

Boration to equal 1% Power Decrease = **20.1** gallons boric acid

Reactivity affects of RCS Temperature

Temperature Coefficient of Reactivity (ITC) = **-21.5** pcm / ☜F

Boration to equal 1☜F Temperature Decrease = **27.1** gallons boric acid

Dilution to equal 1☜F Temperature Increase = **243.0** gallons RMUW

Load Reduction equal to 1☜F T_{ave} Increase = **16.0** MWe

Load Reduction Calculation Worksheet

Note: Do not perform these calculations following a Runback. For a Runback, borate per the Reactivity Briefing Sheets as soon as possible.

This computer generated form may be substituted for Attachment 1 of NUC-117 Rev 8

Contact Core Performance (817-432-0134) if possible to discuss the plan.

Unit ______ **Date / Time:** ____________________

A.1 Boration Volume _______________ **gallons**

Indicate source (listed in order of preference)

___ BEACON by Core Performance (obtain if time permits)
___ Reactivity Briefing Sheets from the Boration Matrix
___ CHORE output (under 'Tools' ->'Power Change Rx Calc IPO-003 ATT 3')
___ IPO-003A Attachment 3 Manual Calculation

A.2 Current Turbine Load Setpoint . . . . _______________ **MWe**

A.3 Final Turbine Load Setpoint . . . . _______________ **MWe**

(200 MWE if plant shutdown planned)

A.4 Total Turbine Ramp Time . . . . _______________ **minutes**

(Do not include calculation prep and Pre-Job Brief times)

Calculations:

B.1 Load Change . . . . _______________ **MWe**

= A.2 - A.3

B.2 Load Rate . . . . _______________ **MWe/min**

= B.1 / A.4

B.3 Total Boration Time . . . . _______________ **minutes**

Ideally, start time should be 5 minutes BEFORE load change is initiated.

If time does not allow, start time should be same as the load change start time.

Ideally, end time should be 15 minutes BEFORE load change is complete.

B.4 Boration Rate . . . . _______________ **gpm**

= A.1 / B.3

B.5 1-FK-110 Pot Setting . . . . _______________ **turns**

= B.4 / 4 (N/A for Batch Boration)

Reactivity Briefing Sheet for Runback to 900 MWe

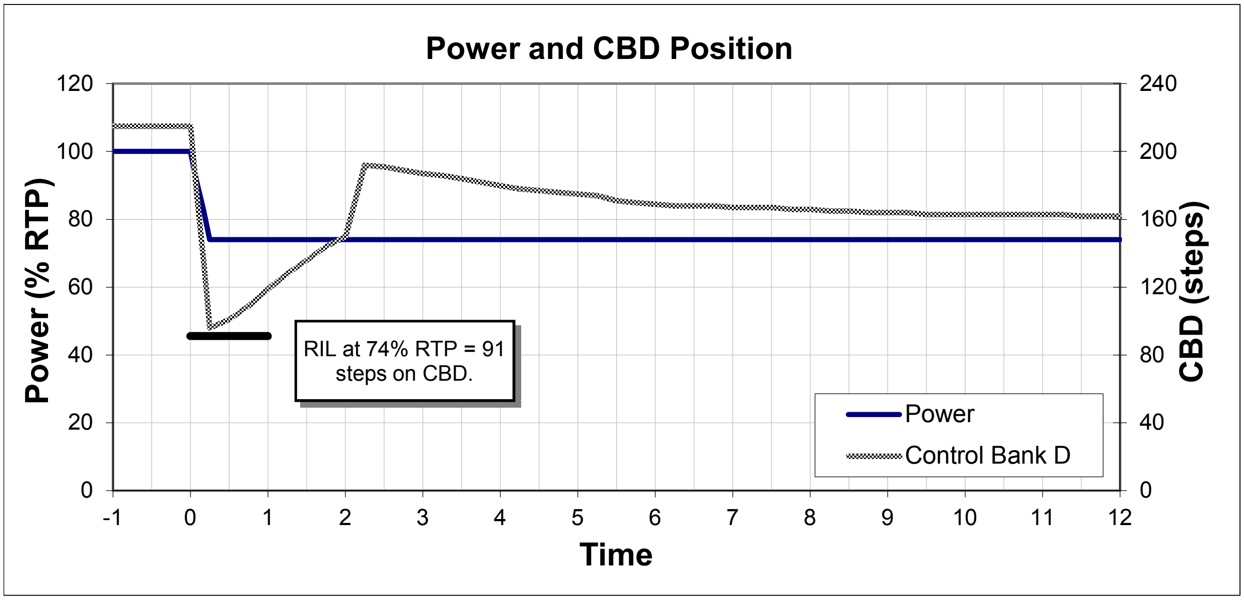
MOL PROJECTIONS - SIMULATOR USE ONLY

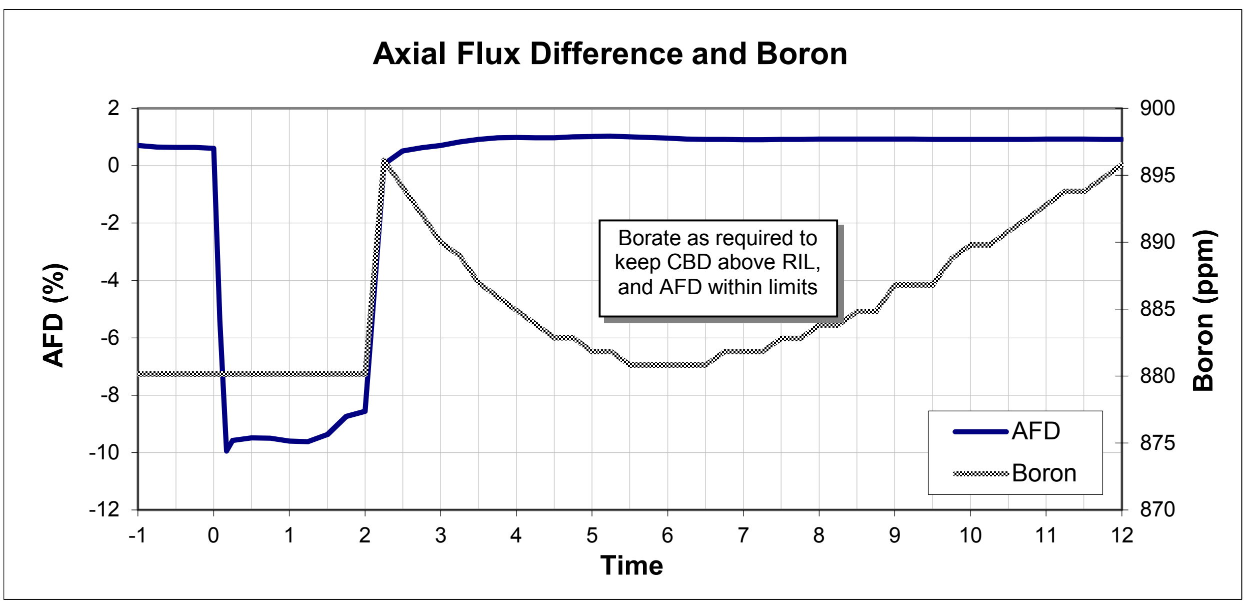
Basic Control Strategy:

A) A boration of 155 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 1200 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Runback to 800 MWe

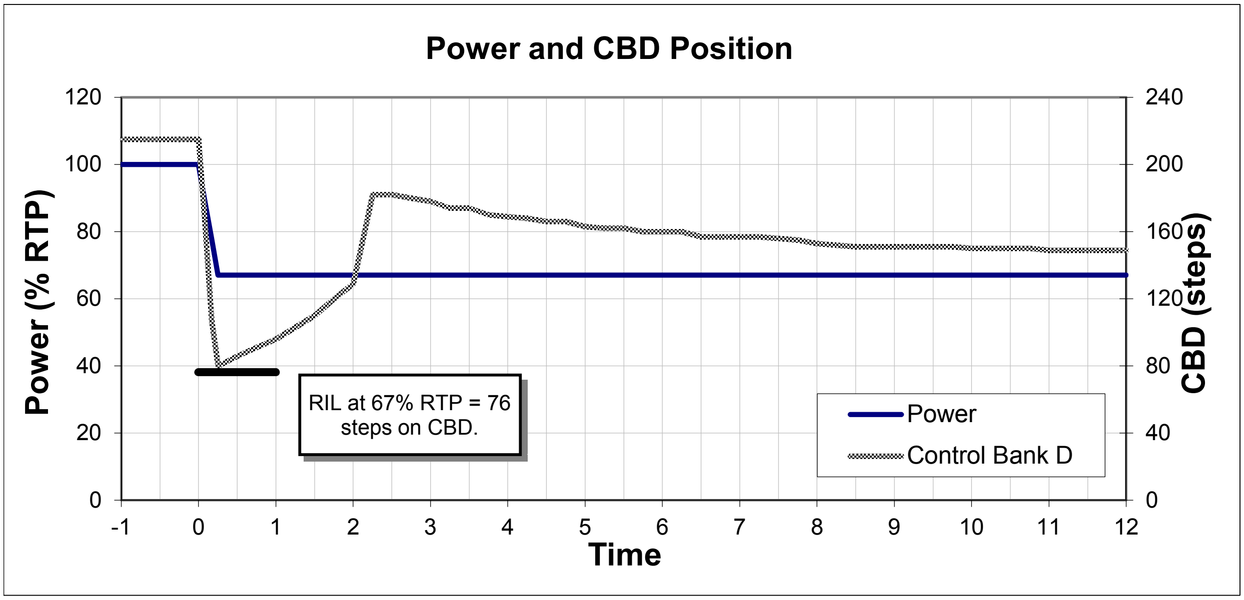
MOL PROJECTIONS - SIMULATOR USE ONLY

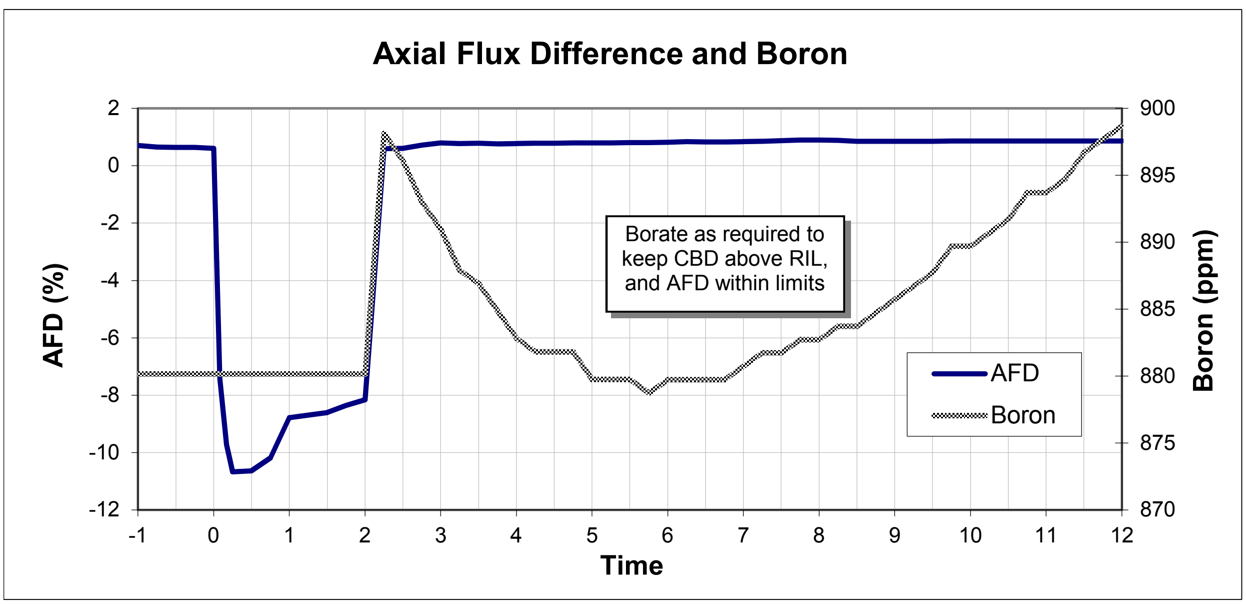
Basic Control Strategy:

A) A boration of 175 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 1500 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Runback to 700 MWe

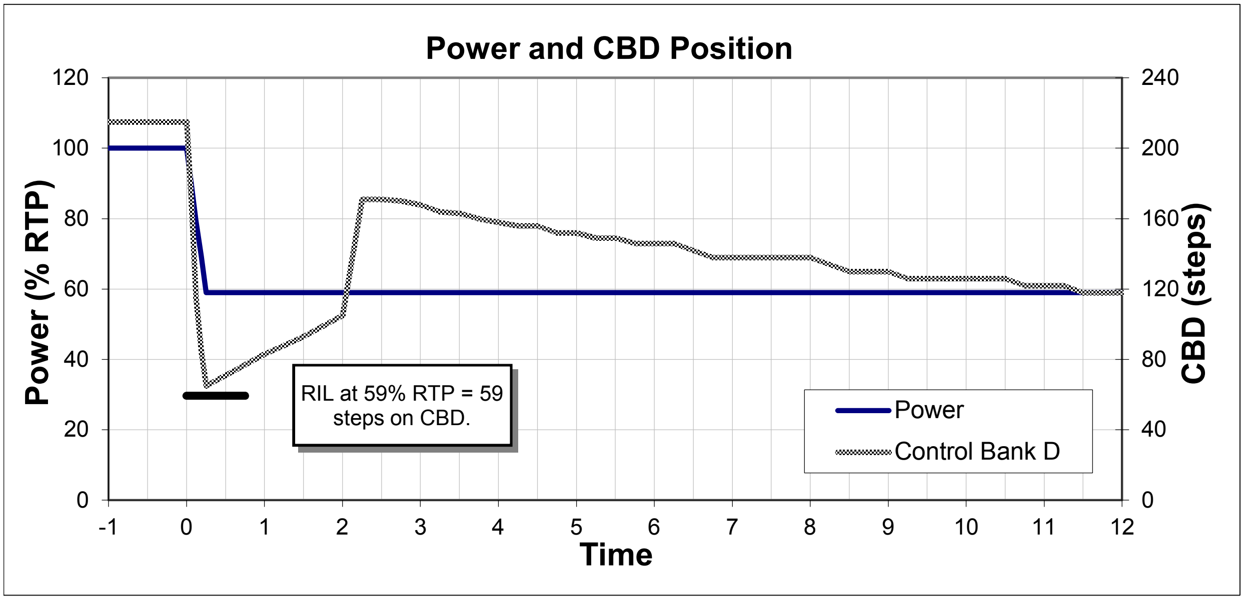
MOL PROJECTIONS - SIMULATOR USE ONLY

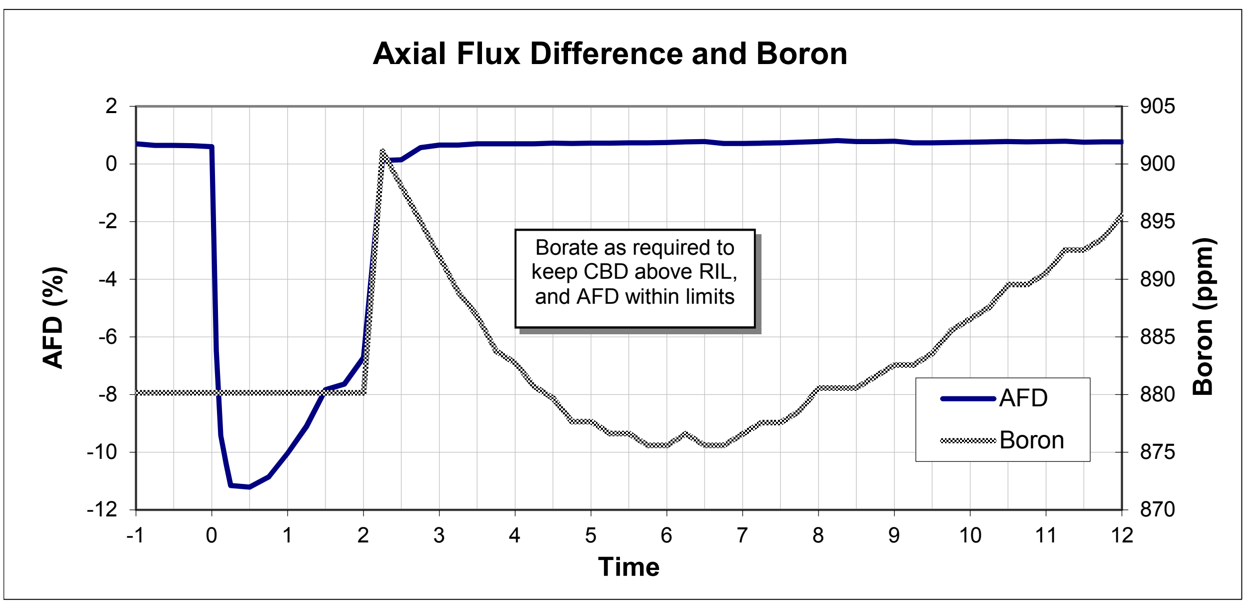
Basic Control Strategy:

A) A boration of 200 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 2000 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Downpower Boration Matrix

MOL PROJECTIONS - SIMULATOR USE ONLY

The boration/dilution estimates are based on BEACON predictions for maintaining Incore Axial Offset.

With deep rod insertion, it is expected AFD indications (based on Excore Detectors) will be less than the Incore value by ~2-4%. In this case, no immediate action is needed to restore AFD, but contact Core Performance.

Borate at a rate sufficient to allow ~15 minutes of mixing before the final power level is reached.

Contact Core Performance as soon as possible when planning ANY downpower for additional support.

Assumed Initial Conditions

Power	100	% RTP
CBD Position	215	steps
RCS Boron	864	ppm *(anticipated boron at middle of validity range)*

30 Minute Ramp Down Boration Estimates

	900 MWe	800 MWe	700 MWe	50% RTP
	(~74% RTP)	(~67% RTP)	(~59% RTP)	
Final CBD Position	*172 steps*	*161 steps*	*148 steps*	*123 steps*
Total Boration	*304 gal*	*384 gal*	*481 gal*	*561 gal*

Dilution in first hour to support maintaining reduced power, while holding Incore AFD on Target:

Followup Dilution (1st hour)	*1102 gal*	*1409 gal*	*1792 gal*	*2435 gal*
Ave Dilution Rate (1st hour)	*18.4 gpm*	*23.5 gpm*	*29.9 gpm*	*40.6 gpm*

Notes: Highlighted values: Max boration rate during downpower may be unable to maintain Target AFD. Restore and hold Target AFD as soon as possible following the Downpower.

2 Hour Ramp Down Boration Estimates

	900 MWe	800 MWe	700 MWe	50% RTP
	(~74% RTP)	(~67% RTP)	(~59% RTP)	
Final CBD Position	*172 steps*	*158 steps*	*142 steps*	*101 steps*
Total Boration	*191 gal*	*232 gal*	*286 gal*	*258 gal*

Dilution in first hour to support maintaining reduced power, while holding Incore AFD on Target:

Followup Dilution (1st hour)	*771 gal*	*1017 gal*	*1292 gal*	*1641 gal*
Ave Dilution Rate (1st hour)	*12.9 gpm*	*17 gpm*	*21.5 gpm*	*27.4 gpm*

1 Hour Rapid Shutdown (Ramp to 20% on Target AFD, 30 minute hold, trip)

	20% RTP
Final CBD Position	*79.2 steps*
Total Boration	*698 gal*

Notes:

After 30 minutes, no dilution (withdrawing rods to control power), holding at 20% RTP

CBD Position	*107.4 steps*	Incore AFD	*2.8 %*

UNIT SUPERVISOR RELIEF CHECKLIST

UNIT 1

OFF-GOING US: Unit Supervisor **SHIFT:** Night **DATE:** Today

ON-COMING US: ____________ **SHIFT:** ____________

PART I TO BE PREPARED BY THE OFF-GOING UNIT SUPERVISOR.

1.0 SHIFT ACTIVITIES:

1.1 Activities Completed This Shift:

ABN-907 Attachment 2

1.2 Activities In-progress:

MD AFW Pump 1-02 motor oil change

Monitoring severe weather in the general area per ABN-907

1.3 Planned Activities:

OPT-206 A when MDAFW work completes

Continue with ABN-907 as necessary

2.0 PLANT AND EQUIPMENT STATUS:

2.1 Technical Specification or Related Equipment Summary

A1-17-0065 ->TS 3.7.5 AFW Condition B.1 - 72 hours for MDAFW 1-02 motor oil change (expected completion in 8 hours)

GEM on 1-HS-2450A

UNIT SUPERVISOR RELIEF CHECKLIST

2.2 **Non-Technical Specification Related Equipment Summary**

No equipment out of service.

3.0 **GENERAL INFORMATION:**

None

4.0 **END OF SHIFT REVIEW:**

LOGS – RO/BOP X LOGS-NEO X CLOSED eLCOARs ARCHIVED X

OPTS COMPLETD X DAILY ACTIVITIES LIST X LCOARs REVIEWED X

COMP ACTIONS REVIEWED X

PART II TO BE COMPLETED BY THE ON-COMING UNIT SUPERVISOR.

1.0 **CRITICAL PARAMETERS:**

MODE: 1 REACTOR POWER: 100 MWe: 1265

RCS TAVE: 585 °F CONTROL ROD POSITION 215 ON BANK D

C_B: 771 ppm RCS PRESS: 2235 psig

2.0 **STATUS REVIEW:**

	X	UNIT LOGS
[C]	X	* * LCOAR AND SYSTEMS IMPORTANT TO SAFETY STATUS [26082, 23486]
	X	UNIT DIFFERENCES (If last watch was on opposite unit)
	X	SHIFT ORDERS
	X	BOARD WALKDOWN
	X	* POD
[C]	X	CONDITIONAL SURVEILLANCE STATUS BOARD [23486]
	X	LOCATION OF SAFEGUARDS INFORMATION
	X	* RISK PROFILE FOR SHIFT

PROTECTED TRAIN [X] Train “A” [ ] Train “B”

* May be completed after turnover.

* * Each US’s (U1 & U2) status review is to include the U1 & Common LCOAR & SIS Logs for Common equipment.

SHIFT RELIEF: ______________________ / ______________ / ______________

ON-COMING US SIGNATURE DATE TIME

Unit Supervisor

OFF-GOING US SIGNATURE

ON-COMING FSS REVIEW

SHIFT MANAGER REVIEW

OWI-107-2
R-10
PAGE 2 OF 2

Facility:	CPNPP 1 & 2	Scenario No.:	3	Op Test No.:	June 2017 NRC
Examiners:		Operators:			

Initial Conditions: 1 x 10^{-8} amps following a refueling outage. MDAFWPs are maintaining Steam Generator Water Levels 60-75%. Steam dumps are in Steam Pressure mode. Boron is 1669 ppm (by sample).

Turnover: Raise power to 3% per IPO-002A, Plant Startup From Hot Standby, Section 5.4

Critical Tasks: **CT 1 -** Initiate a MSLI or Manually close MSLI valves, due to failure to automatically isolate, prior to exiting EOP-0.0A, Reactor Trip or Safety Injection, or EOP-2.0, Faulted Steam Generator Isolation.

CT 2 - Trip reactor coolant pumps within 5 minutes upon a loss of Subcooling per EOP-0.0A, Reactor Trip or Safety Injection OR EOP-1.0A, Loss of Reactor or Secondary Coolant.

Event No.	Malf. No.	Event Type*	Event Description
1	-	R (RO, SRO) N (BOP)	Raise power to 2% to 3%
2	TP06A TP07B	C (BOP, SRO)	Turbine Plant Cooling Water Pump 1 Trip Turbine Plant Cooling Water Pump 2 Failure to Auto-Start
3	OVRD	C (RO, SRO)	Letdown HX Outlet flow controller Failure TK-130 fails low, TCV-129 fails to automatically divert
4	RX08B RX16B	I (RO, SRO) TS (SRO))	PT-456 PZR Pressure Transmitter fails high, PORV PCV-456 fails 25% open
5	FW24B	C (BOP, SRO) TS (SRO)	AFW Pump 1-02 trips, manual start of TDAFW Pump required
6	RD09B6 RD04B6 RD04F6 RC19C	M (ALL)	Seismic event, Ejected rod, SBLOCA @ 1500 gpm, Stuck rod
7	MS02	M (ALL)	Main Steam line leak downstream of the MSIVs (MSLI does not occur automatically)

* (N)ormal, (R)eactivity, (I)nstrument, (C)omponent, (M)ajor, (TS)Technical Specifications

Actual	Target Quantitative Attributes
7	Total malfunctions (5-8)
2	Malfunctions after EOP entry (1-2)
4	Abnormal events (2-4)
2	Major transients (1-2)
2	EOPs entered/requiring substantive actions (1-2)
0	EOP contingencies requiring substantive actions (0-2)
2	Critical tasks (2-3)

SCENARIO 3 SUMMARY

Event 1

In accordance with turnover instructions, the crew begins raising power to 2% to 3%, per IPO-002A, Plant Startup from Hot Standby, Section 5.4, Increasing Reactor Power to Approximately 2% Following Reactor Startup and Establishing Main Feedwater Flow to the SGs.

Event 2

When the lead examiner is satisfied with the power increase (stable between 2-3%) a trip of the running TPCW Pump will occur. The standby pump will fail to automatically start and manual operator action will be required to start the standby pump. Crew response will be per ABN-306, Turbine Plant Cooling Water System Malfunction, Section 3.0. The crew will start the standby pump and verify other parameters for the system.

Event 3

The next event is a failure of the Letdown Heat Exchanger Outlet Flow Controller, TK-130. The controller output will fail to zero demand and cause TCV-4646, LTDN HX OUT TEMP CTRL valve to close. This will result in Letdown Heat Exchanger High temperature alarms and Letdown flow will fail to divert to the VCT on high temperature. The crew will respond per the ALM, manually divert letdown flow to the VCT, and take manual control of TK-130 and raise demand to establish a Letdown Heat Exchanger Outlet temperature of approximately 95°F.

Event 4

Pressurizer Pressure channel PT-456 will fail high. PORV PCV-456 will open and when closed will stick at 25% open. The crew will enter ABN-705, Section 2.0, Pressurizer Pressure Instrument Malfunction. The primary action is to close the PORV block valve. The SRO will refer to Technical Specifications.

Event 5

After the crew has control of RCS pressure, the Motor Driven Auxiliary Feedwater Pump (MDAFWP) 1-02 will trip. The crew will enter ABN-305, Auxiliary Feedwater System Malfunction. The crew will manually start the Turbine Driven Auxiliary Feedwater Pump (TDAFWP) and feed Steam Generators 1-03 and 1-04 with the TDAFWP. The SRO will refer to Technical Specifications.

Event 6

A seismic event occurs; this is a precursor for upcoming events. The crew will enter ABN-907, Acts of Nature, Section 2.0, Earthquake. 120 seconds after the seismic annunciators have come in Control Rod B6 will partially eject from the core (SBLOCA) and Control Rod F6 will stick at 168 steps on the reactor trip. The reactor will trip and the crew will enter EOP-0.0A, Reactor Trip or Safety Injection. Emergency Boration verification via Safety Injection flow will be required due to the 2 Stuck Control Rods. The crew must secure RCPs within 5 minutes of loss of subcooling.

Event 7

A Main steam line break in the turbine building will occur (downstream of the MSIVs,) as a result of the seismic event, requiring the MSIVs to be manually closed as they will fail to close automatically.

Terminating Criteria

Scenario will be terminated when the operators have transitioned to EOS-1.2A, Post LOCA Cooldown and Depressurization, or at the Lead Examiner’s discretion.

Risk Significance:

- Failure of risk significant systems prior to trip: PORV stuck open; MDAFW Pump trips

- Risk significant core damage sequence: Rod Ejection then Small Break LOCA; Main Steam Line Break

- Risk significant operator actions: Manual start of TDAFWP; Manual Main Steam line Isolation

Critical Task Determination

Critical Task	Safety Significance	Cueing	Measurable Performance Indicators	Performance Feedback
Initiate a MSLI or Manually close MSLI valves, due to failure to automatically isolate, prior to exiting EOP-0.0A, Reactor Trip or Safety Injection, or EOP-2.0, Faulted Steam Generator Isolation.	Take one or more actions that would prevent a challenge to plant safety.	SG pressure along with RCS pressure and temperature falling.	The operator will manually close the MSIVs from CB-07.	All MSIV valve light indications will change from Red lit to Green lit and steam flow will go to zero for SGs.
Trip reactor coolant pumps within 5 minutes upon a loss of Subcooling per EOP-0.0A, Reactor Trip or Safety Injection OR EOP-1.0A Loss of Reactor or Secondary Coolant.	Take one or more actions that would prevent a challenge to plant safety. FSAR II.K.3.5; WCAP-9584; WOG ERG Generic Issue for RCP Trip / Restart.	Procedurally driven from EOP-0.0A and EOP-1.0A Foldout pages. Availability of Subcooling indication both on meters and computer.	The operator will secure ALL RCPs using the handswitches on CB-05.	Indication of pump stop including light indication, flow and motor current.

	SIMULATOR OPERATOR INSTRUCTIONS for SIMULATOR SETUP				
INITIALIZE to IC 8 and LOAD NRC Scenario 3.					
EVENT	**TYPE**	**MALF #**	**DESCRIPTION**	**DEMAND VALUE**	**INITIATING PARAMETER**
2	IMF	TP07B	Turbine Plant Cooling Water Pump 2 Fail to Auto-Start	f:1	K0
7	IMF	SS02A1	MSL Isolation Train A Master Relay Failure	f:1	K0
7	IMF	SS02A2	MSL Isolation Train B Master Relay Failure		
2	IMF	TP06A	Turbine Plant Cooling Water Pump 1 Trip	f:1	K2
2	IMF	TP07B	Turbine Plant Cooling Water Pump 2 Fail to Auto-Start	f:1	K0
3	IOR	OVRD	Letdown HX Outlet Flow Controller Failure (TK-130) Fails Low, with a failure of TCV-129 to divert	f:10 OVRD	K3 + 60
4	IMF	RX08B	PT-456 PZR Pressure Transmitter fails high	f:2500	K4
4	IMF	RX16B	PORV PCV-456 fails 25% open.	f:25	K4 + 4
4	IRF	RCR24	PORV Block Valve breaker	f:0	K11
5	IMF	FW24B	AFW Pump 1-02 trips	f:1	K5
6	IRF	AN2A_02	Seismic Event	f:4	K6
		AN2A_03	Seismic Event	f:4	K6
	IMF	RD09B6	Ejected Rod B6	f:228	K6 + 120
		RD04B6	Stuck Rod B6 (ejected – for indication only)	f:228	K6 + 120
		RD04F6	Stuck Rod F6	f:168	K6 +120
		RC19C	SBLOCA	f:1500	K6 + 120 (1)
7	IMF	MS02	Main Steam Line leak downstream of the MSIVs	f:2e+006	K6 + 270
7	IMF	SS02A1	MSL Isolation Train A Master Relay Failure	f:1	K0
7	IMF	SS02A2	MSL Isolation Train B Master Relay Failure		
(1) {DIRPSIA2.Value=1} MMF RC19C f:1750 r:60 Modify SBLOCA to 1750 gpm on SI Initiation (60 sec ramp)					

Simulator Operator:	**INITIALIZE to IC 8 and LOAD NRC Scenario 3.** **ENSURE all Simulator Annunciator Alarms are ACTIVE.** **ENSURE all Control Board Tags are removed.** **ENSURE Operator Aid reflects current boron conditions (1669 ppm BOL).** **ENSURE Rod Bank Update (RBU) is performed (C at 214 / D at 99).** **ENSURE Turbine Load Rate set at 8.9 MWe/minute.** **ENSURE 60/90 buttons DEPRESSED on ASD.** **ENSURE ASD speakers are ON to half volume.** **ENSURE procedures in progress are on SRO desk:** **- COPY of IPO-002A, Plant Startup From Hot Standby, Section 5.4, Increasing Reactor Power to Approximately 2% Following Reactor Startup and Establishing Main Feedwater Flow to the SGs** **ENSURE Control Rods are in MANUAL with Bank C at 214 steps and Bank D at 99.** **ENSURE PCS TT06 is set to "GTGC PWROPS" and on scale.** **ENSURE Steam Dump pot is set for 6.70 turns.** **PLACE Alarms in service for CV-01 and CV-03 on Panel Overview**

Control Room Annunciators in Alarm:
1-ALB-6D-1.1 – SR HI VOLT FAIL
1-ALB-6D-3.1 – SR SHTDN FLUX ALM BLK
PCIP-1.1 – SR TRN A RX TRIP BLK
PCIP-1.3 – AMSAC BLK TURB < 40% PWR C-20
PCIP-1.4 – CNDSR AVAIL STM DMP ARMED C-9
PCIP-1.7 – RX ≤ 50% PWR TURB TRIP PERM P-9
PCIP-2.1 – SR TRN B RX TRIP BLK
PCIP-2.4 – LO TURB PWR ROD WITHDRWL BLK C-5
PCIP-2.5 – SR RX TRIP BLK PERM P-6
PCIP-3.5 – RX & TURB ≤ 10% PWR P-7
PCIP-4.5 – RX ≤ 48% PWR 3-LOOP FLO PERM P-8
PCIP-4.6 – TURB ≤ 10% PWR P-13
1-ALB-7B-1.6 – FW FLUSH VLV NOT CLOSE HV-2166
1-ALB-7B-1.12 – FWPT A TRIP
1-ALB-8A-1.10 – 1 OF 4 TURB STOP VLV CLOSE
1-ALB-9A – Various Heater Drain and Extraction Steam Alarms

Operating Test :	NRC	Scenario #	3	Event #	1	Page	7	of	41
Event Description:	Raise Reactor Power to 2% to 3%								

Time	Position	Applicant's Actions or Behavior
Examiner Note:		**The following steps are from IPO-002A, Plant Startup From Hot Standby, Section 5.4, Increasing Reactor Power to Approximately 2% Following Reactor Startup and Establishing Main Feedwater Flow to the SGs, Step 5.4.1.B.**

CAUTION:

- The preferred methods to maintain Reactor Power and temperature prior to Turbine Generator synchronization are use of Steam Dumps and SG Blowdown Flow. Steam Dump operation and Main Steam Line Drain flow affect LP Turbine casing ΔT, which should be monitored prior to synchronization.
- If LP Turbine casing ΔT approaches limits prior to synchronization, a reduction in Steam Dump operation may be required, and Main Steam Line drain flow should also be limited.
- The preferred method, to reduce Steam Dump Operation and Main Steam Line drain flow, is maintaining maximum SG Blowdown flow.
- SG Atmospherics should not be routinely used to minimize Steam Dump operation.

NOTE:

- The verification of Power Range response and reaching the point of adding heat can be used to ensure proper Nuclear Instrumentation response.
- Intermediate Range should be monitored and/or trended to provide alternate indication of how power is trending. At low power, Power Range Instruments may not give an accurate trend of actual power.

Time	Position	Applicant's Actions or Behavior
	RO	WITHDRAW control rods to establish a 0.5 dpm startup rate. [Step 5.4.1.B]
	RO	REDUCE startup rate to 0.2 dpm at approximately 3X10^{-6} amps. [Step 5.4.1.C]
	RO	VERIFY the Power Range channels begin to respond. [Step 5.4.1.D].
	RO	VERIFY Steam Dumps are maintaining temperature. [Step 5.4.1.E]
	RO	VERIFY 1-PCIP, 3.6 TAVE LO LO P-12 is OFF. [Step 5.4.1.G]

Operating Test : NRC	Scenario # 3	Event # 1	Page 8 of 41
Event Description: Raise Reactor Power to 2% to 3%			

Time	Position	Applicant's Actions or Behavior
	RO	Maintain Reactor Power between 2% and 3%. [Step 5.4.1.H]
When the crew has demonstrated that they can maintain power stable between 2% and 3%, or at Lead Examiner discretion, PROCEED to Event 2.		

Operating Test :	NRC	Scenario #	3	Event #	2	Page	9	of 41
Event Description:	TPCW Pump 1-01 Trip. TPCW Pump 1-02 AUTO start fails							

Time	Position	Applicant's Actions or Behavior
Simulator Operator: When directed, EXECUTE Event 2 (Key 2). - TP06A, TPCW Pump 1-01 Trip. TP07B, TPCW Pump 1-02 AUTO start fails.		
Indications Available: **9A-3.10 – TPCW PMP 1 OVRLOAD/TRIP** **1-FI-3061, TPCW PMP DISCH FLO, indicating 0 gpm** **1-HS-3060, TPCW PMP 1, Orange MISMATCH light LIT AND White TRIP light LIT** **1-HS-3139, TPCW PMP 2, Green light ON – Red light OFF, indicating pump NOT running**		
	BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE TPCW Pump 1-01 has Tripped AND TPCW Pump 1-02 has failed to automatically start.
Examiner Note: **The crew may immediately start TPCW Pump 1-02 based on ODA-102 guidance which allows the operator to manually perform an action that should have occurred automatically.**		
	BOP	PERFORM 1-ALB-9A, Window 3.10, TPCW PMP OVRLOAD/TRIP
CAUTION: If TPCW pump damage is indicated, the 86M relay should NOT be reset until Maintenance personnel have been notified to investigate cause of trip condition. Placing handswitch in STOP will reset 86M relay (white TRIP light).		
Simulator Operator: **When contacted about status of TPCW Pump 1-01, wait 3 minutes and REPORT Phase 'B' 50/51 overcurrent relays are tripped at the breaker and an acrid odor is present at the TPCW Pump.**		
	BOP	ENSURE a standby TPCW pump is operating: [Step 1] • 1-HS-3139, TPCW PMP 2 - NO
	BOP	• START TPCW Pump 1-02 using 1-HS-3139
Examiner Note: **The following step is Not Applicable as the operator should start TPCW pump 1-02 and verify it is running prior to performing this step.**		
	BOP	IF NO TPCW pump operating, THEN GO to ABN-306 for Loss of TPCW.

Operating Test : NRC	Scenario # 3	Event # 2	Page 10 of 41
Event Description: TPCW Pump 1-01 Trip. TPCW Pump 1-02 AUTO start fails			

Time	Position	Applicant's Actions or Behavior
		[Step 1A]
	BOP	IF TPCW Pump 1-01 tripped, THEN REFER to ABN-306 for TPCW Pump Malfunction. [Step 1B]
	US	DIRECT entry into ABN-306, Turbine Plant Cooling Water System Malfunction, Section 3.
Simulator Operator: When contacted as the prompt team, acknowledge the request.		
Examiner Note: The following steps are from ABN-306, TPCW System Malfunction.		
CAUTION: Damage to the pump may result from prolonged operation at flow below 4,700 gpm.		
	BOP	VERIFY TPCW Head Tank Level – GREATER THAN 6%. [Step 3.3.1] • 1-LI-3051, TPCW HEAD TK LVL • L6907A, TPCW HEAD TANK LEVEL
NOTE: With standby TPCW Pump handswitch in AUTO, the pump will AUTO start if the running pump trips, provided LO-LO TPCW Tank level signal is NOT present.		
	BOP	VERIFY at least ONE TPCW Pump – RUNNING: [Step 3.3.2] • 1-HS-3139, TPCW PMP 2
	BOP	VERIFY TPCW Head Tank Level – GREATER THAN 20%. [Step 3.3.3] • 1-LI-3051, TPCW HEAD TK LVL • L6907A, TPCW HEAD TANK LEVEL
	BOP	VERIFY 1-FI-3061, TPCW PMP DISCH FLO – WITHIN LIMITS [Step 3.3.4] (F2701A01, is a one minute average of TPCW flow).
		• VERIFY TPCW flow – GREATER THAN 4700 GPM and LESS THAN 22000 GPM

Operating Test :	NRC	Scenario #	3	Event #	2	Page	11	of	41
Event Description:	TPCW Pump 1-01 Trip. TPCW Pump 1-02 AUTO start fails								

Time	Position	Applicant's Actions or Behavior
		CAUTION: Unless cause of trip is known, TPCW Pump 86M Relay should not be reset until Maintenance Department has investigated cause of trip. Placing handswitch in STOP resets 86M Relay (white TRIP light).
	BOP	CHECK BOTH TPCW Pumps – NOT tripped: [Step 3.3.5] • 1-HS-3139, TPCW PMP 2 RUNNING
		• Locally PERFORM the following: [Step 3.3.5 RNO] • INSPECT TPCW Pump 1-01 for signs of damage, smoke, burn odors, overheating (TB 778) [Step 3.3.5 RNO a] • INSPECT TPCW Pump 1-01 breaker for dropped relay flag (TB SWGR Rm) [Step 3.3.5 RNO b] • 1A3/3/BKR, TURBINE PLANT COOLING WATER PUMP 1-01 MOT BKR • NOTIFY Maintenance Department of any abnormal condition or finding [Step 3.3.5 RNO c]
	BOP	VERIFY TPCW Pumps – ONLY ONE RUNNING: [Step 3.3.6] • 1-HS-3139, TPCW PMP 2
	US	INITIATE Issue Report per STA-421, as applicable. [Step 3.3.7]
		When the plant is stable or at Lead Examiner's discretion, PROCEED to Event 3.

Operating Test :	NRC	Scenario #	3	Event #	3	Page	12	of	41
Event Description:	Letdown HX Outlet flow controller Failure TK-130 fails low, TCV-129 fails to automatically divert								

Time	Position	Applicant's Actions or Behavior
Simulator Operator: **When directed, EXECUTE Event 3 (Key 3). Event 3 will occur 60 seconds after Key 3 is initiated.** **- OVRD, LTDN HX Outlet Flow Controller Failure (TK-130) Fails Low, TCV-129 fails to automatically divert.**		
Indications Available: **6A-1.3 – LTDN HX OUT TEMP HI** **6A-2.3 – LTDN HX NORM OUT FLO DIVERT** **1-TI-130, LTDN HX OUT TEMP Rising**		
	RO	RESPOND to Annunciator Procedure Alarms.
	RO	RECOGNIZE 1-TK-130, LTDN HX OUT TEMP CTRL has failed to 0% output and 1-TI-130, LTDN HX OUT TEMP is rising.
Examiner Note: **The operator may take manual control of 1-TK-130 and open TCV-4646 as an automatic control system has malfunctioned, per ODA-102.** **The operator may manually divert TCV-129 to the VCT as an automatic action has malfunctioned, per ODA-102.**		
	RO	Performs actions of ALM-0061A, 1-ALB-6A, Window 1.3 – LTDN HX OUT TEMP HI
NOTE: 1/1-TCV-129, LTDN DIVERT VLV diverts flow to the VCT if letdown temperature is >135°F or BTRS demineralizer inlet temperature is >155°F.		
	RO	MONITOR 1-TI-130, LTDN HX OUT TEMP. [Step 1]
		IF temperature increases to ≥ 135°F, ensure 1/1-TCV-129, LTDN DIVERT VLV is diverted to the VCT. [Step 1.A] • When temperature reaches 135°F the operator will be required to manually divert letdown flow to the VCT. • PLACE 1/1-TCV-129, LTDN DIVERT VLV in the VCT position.
	RO	MONITOR 1-TI-381, BTRS DEMIN IN TEMP. [Step 2]
		• The BTRS system is NOT in service. [Step 2.A]

Operating Test :	NRC	Scenario #	3	Event #	3	Page 13	of 41
Event Description:	Letdown HX Outlet flow controller Failure TK-130 fails low, TCV-129 fails to automatically divert						

Time	Position	Applicant's Actions or Behavior
	RO	VERIFY charging flow is 12 gpm greater than letdown flow. [Step 3]
	RO	VERIFY 1-TI-127, REGEN HX LTDN OUT TEMP is ≤ 350°F. [Step 4]
		1-TI-127, REGEN HX LTDN OUT TEMP is NOT > 350°F. [Step 4.A]
	BOP	VERIFY 1-ZL-4646, LTDN HX CCW RET VLV is OPEN. (1-CB-03) [Step 5]
	RO	IF 1-ZL-4646 is CLOSED, place 1-TK-130, LTDN HX OUT TEMP CTRL in manual AND adjust letdown heat exchanger outlet temperature to 95°F. [Step 5.A]
		• The controller will respond appropriately in MANUAL to control letdown heat exchanger outlet temperature at 95°F. [Step 5.B]
	RO	ENSURE 1-TI-130, LTDN HX OUT TEMP is maintained < 125°F. [Step 6]
		• Letdown heat exchanger outlet temperature can be maintained < 125°F with 1-TK-130 in manual. [Step 6.A]
	US/RO	NOTIFY Chemistry and Radiation protection personnel that Letdown has diverted to the VCT. [Step 7]
	US	Correct the condition or initiate a work request per STA-606. [Step 8]
When Letdown Heat Exchanger Outlet Temperature is appropriately controlled, or at Lead Examiner discretion, PROCEED to Event 4.		

Operating Test :	NRC	Scenario #	3	Event #	4	Page	14	of	41
Event Description:	PT-456 fails High, PORV PCV-456 fails open and fails to reseat, remains 25% open								

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Event 4 (Key 4).** **- RX08B, PZR Pressure Transmitter PT-456 fails high** **- RX16B, PORV PCV-456 fails open and fails to reseat remains 25% open**
Indications Available:		**5B-3.1 – PRZR PORV OUT TEMP HI** **5B-4.1 – PRZR ANY SFTY RLF VLV OUT TEMP HI** **5C-1.4 – PORV 455A/456 NOT CLOSE** **5C-2.1 – PRZR PRESS HI** **5C-3.1 – PRZR 1 OF 4 PRESS HI** **5C-3.3 – PRZR PRESS LO BACKUP HTRS ON** **1-PI-456, PRZR PRESS CHAN II failed high** **1/1-PCV-456, PRZR PORV indicates mid position**
	RO	RESPOND to Annunciator Alarm Procedures.
	RO	RECOGNIZE pressurizer pressure lowering.
	US	DIRECT performance of ABN-705, Pressurizer Pressure Malfunction, Section 2.0.
Examiner Note:		**Diamond steps (◊) are Initial Operator Actions.**
NOTE:		• Diamond steps denote initial action. • A PORV is not considered INOPERABLE when its actuation instrumentation is not functioning. • Power should NOT be removed from a block valve closed in accordance with this procedure section.
	◊ RO ◊	VERIFY PORV – CLOSED. [Step 2.3.1]
		• IF PORV OPEN and RCS Pressure < 2335 psig, THEN CLOSE affected PORV and CLOSE associated block valve. [Step 2.3.1 RNO]
	◊ RO ◊	• PLACE 1/1-PCV-456, PRZR PORV in CLOSE. [Step 2.3.1 RNO]
	◊ RO ◊	• PLACE 1/1-8000B, PRZR PORV BLK VLV in CLOSE. [Step 2.3.1 RNO]

Operating Test :	NRC	Scenario #	3	Event #	4	Page	15	of	41
Event Description:	PT-456 fails High, PORV PCV-456 fails open and fails to reseat, remains 25% open								

Time	Position	Applicant's Actions or Behavior
	◊ RO ◊	PLACE 1-PK-455A, PRZR MASTER PRESS CTRL in MANUAL. [Step 2.3.2]
	◊ RO ◊	ADJUST 1-PK-455A for current RCS pressure. [Step 2.3.3]
	RO	TRANSFER to an Alternate Controlling Channel, if required. [Step 2.3.4] • 1/1-PS-455F, PRZR PRESS CTRL CHAN SELECT to the 455/458 position
	RO	PLACE 1-PK-455A, PRZR MASTER PRESS CTRL in AUTO. [Step 2.3.5]
	RO	VERIFY automatic control restoring Pressurizer pressure to 2235 PSIG. [Step 2.3.6]
	RO	ENSURE valid channel selected to recorder. [Step 2.3.7] • 1/1-PS-455G, 1-PR-455 PRZR PRESS SELECT already selected to the 455 position (valid channel).
	RO	IF necessary, OPEN PORV closed in Step 1 RNO to AUTO and ENSURE it remains CLOSED. [Step 2.3.8]
		• DETERMINES 1-PCV-456 is in mid position and should remain in closed.
	RO	If necessary, OPEN block valve closed in step 1. [Step 2.3.9]
		• DETERMINES 1-PCV-456 is in mid position and Block Valve 1/1-8000B should remain in closed.
NOTE: It may be necessary to leave the PORV Block Valve closed to aid in establishing a water seal. Reference ALM-0053A/B.		
	US/RO	Within one hour, VERIFY PCIP Window 2.6 - PRZR PRESS SI BLK PERM P-11 – DARK. [Step 2.3.10]

Operating Test :	NRC	Scenario #	3	Event #	4	Page	16	of 41
Event Description:	PT-456 fails High, PORV PCV-456 fails open and fails to reseat, remains 25% open							

Time	Position	Applicant's Actions or Behavior
	US/RO	VERIFY other instruments on common instrument line – NORMAL. [Step 2.3.11]
		• VERIFY Loop 2 Instruments LT-460 responding normally per Attachment 1.

NOTE:

- If the failed channel temperature was reading lower than the substituted channel, then AVE Tave will increase when the channel is defeated due to another channel being substituted for the defeated signal to maintain accurate averaging.
- Rod Control is not required to be placed in MANUAL until a Tave loop is defeated using u-TS-412T. As long as a Tave loop is defeated, Rod Control should remain in MANUAL. This does not preclude placing rods in AUTO during rapidly changing transient conditions such as runbacks, etc. as long as rod control is returned to MANUAL when the plant is stabilized. The affected Tave loop does not need to be defeated until just prior to tripping bistables (tripping bistables will cause the N16 and Tave loop to fail low).

Examiner Note: Technical Specification 3.4.1, RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits do NOT apply in Mode 2.

Time	Position	Applicant's Actions or Behavior
	US	EVALUATE Technical Specifications. [Step 2.3.14]
		• LCO 3.3.1.E, Reactor Trip System Instrumentation. (Functions 6, Overtemperature N-16 & 8.b, Pressurizer Pressure High)
		• CONDITION E - One channel inoperable. • ACTION E.1 - Place channel in trip within 72 hours, OR • ACTION E.2 - Be in MODE 3 within 78 hours.

Examiner Note: Technical Specification 3.3.1, Reactor Trip System (RTS) Instrumentation, Function 8.a, "Pressurizer Pressure LOW" does NOT apply in current plant conditions. Must be in MODE 1 and above the P-7 (At Power Permissive) interlock for this Function to apply.

Time	Position	Applicant's Actions or Behavior
		• LCO 3.3.2.D, ESFAS Instrumentation. (Function 1.d, Pressurizer Pressure Low)
		• CONDITION D - One channel inoperable. • ACTION D.1 - Place channel in trip within 72 hours, OR • ACTION D.2.1 - Be in MODE 3 within 78 hours, AND • ACTION D.2.2 - Be in MODE 4 within 84 hours.

Operating Test :	NRC	Scenario #	3	Event #	4	Page	17	of	41
Event Description:	PT-456 fails High, PORV PCV-456 fails open and fails to reseat, remains 25% open								

Time	Position	Applicant's Actions or Behavior
		• LCO 3.3.2.L, ESFAS Instrumentation. (Function 8.b, Pressurizer Pressure P-11)
		• CONDITION D - One or more required channel(s) inoperable. • ACTION L.1 - Verify interlock is in required state for existing unit condition within 1 hour, <u>OR</u> • ACTION L.2.1 - Be in MODE 3 within 7 hours, <u>AND</u> • ACTION L.2.2 - Be in MODE 4 within 13 hours.
<u>Simulator Operator</u>: When contacted to remove power to 1/1-8000B, PRZR PORV BLK VLV, EXECUTE remote function RCR24 (Key 11), 1/1-8000B to OFF.		
		• LCO 3.4.11.B, Pressurizer Power Operated Relief Valves (PORVs)
		• CONDITION B - One PORV inoperable and not capable of being manually cycled. • ACTION B.1 – Close associated block valve within 1 hour, <u>AND</u> • ACTION B.2.1 – Remove power from associated block valve within 1 hour, <u>AND</u> • ACTION B.2.2 – Restore PORV to OPERABLE within 72 hours.
	US	INITIATE a work request per STA-606. [Step 2.3.15]
	US	INITIATE a SMART Form per STA-421. [Step 2.3.16]
When Technical Specifications are addressed, or at Lead Examiner discretion, PROCEED to Event 5.		

Operating Test :	NRC	Scenario #	3	Event #	5	Page	18	of	41
Event Description:	Motor Driven Auxiliary Feedwater Pump (MDAFWP) 1-02 trip								

Time	Position	Applicant's Actions or Behavior
Simulator Operator: **When directed, EXECUTE Event 5 (Key 5).** **- FW24B, Motor Driven Auxiliary Feedwater Pump (MDAFWP) 1-02 trip.**		
Indications Available: **8B-4.3 - MD AFWP 1/2 OVRLOAD/TRIP** **1-HS-2451A, MD AFWP 2, amber MISMATCH and green PUMP lights LIT** **SGs 1-03 & 1-04 AFW FLO Indicators indicating (0) GPM (1-FI-2465A/C and 1-FI-2466A/C)** **MD AFWP 2 CURRENT indicating (0) AMPS (1-II-2451)** **MD AFWP 2 DISCH PRESS indicating (0) PSIG (1-PI-2454A)** **MD AFWP 2 DISCH FLO indicating (0) GPM (1-FI-2457A)** **SGs 1-03 & 1-04 LVL (NR) decreasing (1-LI-553/554 SGs 1-03/4 Controlling NR Channels)**		
	RO/BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE trip of Motor Driven Auxiliary Feedwater Pump 1-02.
	US	DIRECT performance of ABN-305, Auxiliary Feedwater System Malfunction
Examiner Note: **The following steps are from ABN-305, Auxiliary Feedwater System Malfunction**		
Examiner Note: **The crew may immediately start the TDAFW Pump to arrest the drop in Steam Generator Water Level and follow-up their actions with ABN-305**		
CAUTION: Placing the pump handswitch in STOP OR PULL-OUT with the pump tripped (white TRIP light) will reset the 86M relay (white TRIP light) and may result in an automatic restart if the handswitch is returned to AUTO.		
	US/BOP	DETERMINE which MD AFW Pump is malfunctioning AND verify affected pump - TRIPPED. [Step 3.3.1]
		• DETERMINES AFW Pump 1-02 has tripped. • 1-HS-2451A, MD AFWP 2, amber MISMATCH and green PUMP lights LIT

Operating Test :	NRC	Scenario #	3	Event #	5	Page	19	of	41
Event Description:	Motor Driven Auxiliary Feedwater Pump (MDAFWP) 1-02 trip								

Time	Position	Applicant's Actions or Behavior
		CAUTION: Do not exceed 800 gpm total flow on one Motor Driven Auxiliary Feedwater Pump.
	BOP	VERIFY at least one AFW Pump running. [Step 3.3.2] • MDAFWP 1-01 is RUNNING
		CAUTION: Do NOT operate both Motor-Driven Auxiliary Feedwater Pumps at the same time with the trains cross-connected.
	BOP	Verify Steam Generator levels - NORMAL. [Step 3.3.3]
		• DETERMINES Steam Generator 3 & 4 levels trending down
		• IF the TD AFW Pump is available, THEN START the TD AFW Pump AND FEED the two steam generators NOT being supplied by the MD AFW Pump. [Step 3.3.3 RNO]
		• START the TDAFW Pump and FEED Steam Generators 1-03 and 1-04
		• OPEN 1-HS-2452-1, AFWPT STM SPLY VLV MSL 4 from SG 1-04
		• OPEN 1-HS-2452-2, AFWPT STM SPLY VLV MSL 1 from SG 1-01
Examiner Note: **The crew may feed all 4 Steam Generators with the TDAFWP to ensure minimum flow requirements are met.**		
Simulator Operator: **When contacted, REPORT the breaker for MD AFW Pump 1-02 tripped on overcurrent and the motor is hot to the touch.**		
	US	DISPATCH a NEO to check breaker status of affected auxiliary feedwater pump. [Step 3.3.4]
		• 1EA2/13/BKR, 1APMD2, AUXILIARY FEEDWATER PUMP 1-02 BKR (SFGD 852 Rm 1-103)

Operating Test :	NRC	Scenario #	3	Event #	5	Page	20	of	41
Event Description:	Motor Driven Auxiliary Feedwater Pump (MDAFWP) 1-02 trip								

Time	Position	Applicant's Actions or Behavior
	BOP	Verify MD AFW Pump suction pressure greater than or equal to 10 psig. [Step 3.3.5]
	US	Dispatch an NEO to affected MD AFW Pump Room to inspect pump condition. [Step 3.3.6]
		• Pump casing and discharge piping at ambient temperature • Pump and pump motor – NO APPARENT DAMAGE • No excessive leakage
		• IF pump casing OR discharge piping temperature indicates possible steam binding AND there is NO apparent damage, THEN PERFORM the following: Step is N/A [Step 3.3.6 RNO a]
	US	• If damage to motor or pump is apparent, or excessive leakage is found, THEN PERFORM the following: [Step 3.3.6. RNO b]
		• REFER to Technical Specification 3.7.5 for LCO. [Step 3.3.6 RNO b.1)]
		• LCO 3.7.5, Auxiliary Feedwater (AFW) System
		• CONDITION B - One AFW train inoperable for reasons other than Condition A. • ACTION B.1 - Restore AFW train to OPERABLE status within 72 hours.
		• COMPLETE a Condition Report per STA-421 [Step 3.3.6 RNO b.2)]
		• REFER to STA-706 [Step 3.3.6 RNO b.3)]
		• REFER to EPP-201 [Step 3.3.6 RNO b.4)]
		• RESTORE Auxiliary Feedwater System to Operable status per OPT-206A/B. [Step 3.3.6 RNO b.5)]
		VERIFY affected AFW Pump is required to maintain Steam Generator levels. [Step 3.3.7] • MDAFWP 1-02 is NOT required to maintain SG Water Levels
		GO TO procedure and step in effect. [Step 3.3.8]

When Steam Generator Levels are being maintained between 60% and 75%, and Technical Specifications have been addressed, or at Lead Examiner discretion, PROCEED to Event 6.

Operating Test : NRC	Scenario # 3	Event # 6	Page 21 of 41
Event Description: Seismic Event			

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Event 6 (Key 6).** **- ALB-02A-2.1, Seismic Monitoring System Activation.** **- ALB-02A-3.1, Operating Basis Earthquake Exceedance.**
Indications Available: **2A-2.1 – SEISMIC MONITORING SYSTEM ACTIVATION** **2A-3.1 – OBE EXCEEDANCE** **YELLOW OBE light on Seismic Monitoring Panel** **RED EVENT light on Seismic Monitoring Panel**		
	BOP	RESPOND to Annunciator Alarm Procedures.
	US	DIRECT performance of ABN-907, Acts of Nature, Section 2.0, Earthquake.

NOTE:

- During an actual seismic event, evaluations and inspections should be completed within four hours of the event with the exception of the operator pre-shutdown walkdown inspection to verify no damage or changes to plant equipment. Walkdowns should be completed within eight hours of the event. Results of evaluations and inspections should be reported to the NRC at the end of the 8 hours.
- [C] Restart following a seismic event induced trip of one or both Units cannot be initiated until it is confirmed that the OBE was not exceeded AND that the seismic event did not cause any damage.
- [C] Seismic event induced damage to one or both Units is required to be treated as if the OBE had been exceeded.
- [C] The PCMCIA card with the seismic data should only be removed by the System Engineer or his designee.

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**As Security contact the Control Room and report that ground motion was felt in the Safeguards Building**
	US	IF there are indications (i.e. movement felt or report from government agencies) of a seismic event without an alarm from the Seismic Monitoring System, THEN [Step 2.3.1]
		• MONITOR local news media for reports of a seismic event. [Step 2.3.1.a]

Time	Position	Applicant's Actions or Behavior
		• CHECK: USGS Website link on the Operations Department | Website for the following information: [Step 2.3.1.b] - Confirmation of an earthquake. - earthquake magnitude - earthquake epicenter
		• CONTACT System Engineering to evaluate USGS information to determine whether OBE has been exceeded. [Step 2.3.1.c]
	US	CONTACT I&C to perform channel operational test per INC-7694A, Section 8.3 on the Seismic Monitoring System. [Step 2.3.2] <u>AND</u> VERIFY COT SAT.
NOTE: [C]		• If the Seismic Monitoring Systems declares that the OBE was indeed exceeded, RNO steps (a) thru (c) can not be used to override the OBE exceedance conclusion but can only serve to verify that a seismic event has indeed occurred. • Step 3 should not be delayed and should be performed in parallel with Step 2.
	BOP	DETERMINE Control Room Seismic Monitoring annunciators have alarmed. [Step 2.3.3]
		• 1-ALB-2A, window 2.1
		• 1-ALB-2A, window 3.1
		• Red Event light
		• Yellow OBE light
	CREW	Prompt Operator Actions to be completed within 4 hours of the seismic event: [Step 2.3.4]
		• Primary coolant and secondary system radiation, temperature, pressure, and flow parameters for changes and excursions coincident with the earthquake.
Events 7/8/9 Will occur 120 seconds after the seismic annunciators are received.		

Operating Test :	NRC	Scenario #	3	Event #	7, 8	Page	23	of	41
Event Description:	Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure								

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Events 7, and 8 (Key 6) delayed 120 seconds - RD06H8, Ejected Rod, SBLOCA 1500 gpm - RD04F6, Stuck Rod, Steam leak downstream of MSIVs, MSLI Failure**
Indications Available: **2A-2.8 – ANY CNTMT SMP PMP RUN** **2B-4.12 – CNTMT FN CLR 1 & 2 CNDS FILL RATE HI** **2B-3.12 – CNTMT FN CLR 3 & 4 CNDS FILL RATE HI** **5B-3.4 – PRZR 1 OF 4 PRESS LO** **5B-4.4 – PRZR 1 OF 4 SI PRESS LO** **5B-3.6 – PRZR LVL LO** **5C-1.2 – PRZR LVL DEV LO** **5C-3.3 – PRZR PRESS LO BACKUP HTRS ON**		
	RO/BOP	RECOGNIZE Pressurizer level and pressure – LOWERING.
Examiner Note:		**Crew should manually initiate Reactor Trip and Safety Injection prior to an automatic Reactor Trip and Safety Injection occurring.**
	US	DIRECT performance of EOP-0.0A, Reactor Trip or Safety Injection.
Examiner Note:		**The following steps are from EOP-0.0A, Reactor Trip or Safety Injection.**
	RO	VERIFY Reactor Trip: [Step 1]
		• VERIFY Reactor Trip Breakers – OPEN. [Step 1.a]
		• VERIFY Neutron flux – DECREASING. [Step 1.a]
		• IDENTIFY ONE Control Rod Position Rod Bottom Lights – NOT LIT and ONE other Control Rod indicates Ejected [Step 1.b]
	BOP	VERIFY Turbine Trip: [Step 2]
		• VERIFY all HP Turbine Stop Valves – CLOSED. [Step 2]
	BOP	VERIFY Power to AC Safeguards Buses: [Step 3]
		• VERIFY AC Safeguards Buses – AT LEAST ONE ENERGIZED. [Step 3.a]
		• VERIFY both AC Safeguards Buses – ENERGIZED. [Step 3.b]

Operating Test : NRC	Scenario # 3	Event # 7, 8	Page 24 of 41
Event Description: Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure			

Time	Position	Applicant's Actions or Behavior
	RO	CHECK SI Status: [Step 4]
		• Check if SI is Actuated: [Step 4.a]
		• SI actuation as indicated on the First Out Annunciator 1-ALB-6C.
		• SI Actuated blue status light - ON
		• VERIFY Both Trains SI Actuated: [Step 4.b]
		• SI Actuated blue status light - ON NOT FLASHING

Examiner Note: **Emergency Boration flow will be credited by using SI Flow. The crew should verify Emergency Boration flow using ABN-107, Attachment 4, Transfer of Charging Pump Suction to the RWST OR The Job Aid.**

Examiner Note: **The following steps are from ABN-107, Attachment 4; Transfer of Charging Pump Suction to the RWST OR The Job Aid to verify Emergency Boration.**

CAUTION: Injecting through a CCP SI ISOL VLV (8801A/B) requires CCP SI injection check valve leak test within 24 hours per SR 3.4.14.1 (requires MODE 3, 4, or 5).

Time	Position	Applicant's Actions or Behavior
	RO	IF Safety Injection actuated (1/1-LCV-112D OR 1/1-LCV-112E OPEN), THEN perform the following steps: [Step 1]
		• VERIFY ONE of the following valves OPEN: [Step 1.a] • 1/1-LCV-112D, RWST TO CHRG PMP SUCT VLV. OR • 1/1-LCV-112E, RWST TO CHRG PMP SUCT VLV.
		• VERIFY the following valves CLOSED: [Step 1.b] • 1/1-LCV-112B, VCT TO CHRG PMP SUCT VLV. AND • 1/1-LCV-112C, VCT TO CHRG PMP SUCT VLV.
		• VERIFY at least ONE CCP running: [Step 1.c] • 1/1-APCH1, CCP1 • 1/1-APCH2, CCP2
		• VERIFY 1-FI-917, CCP SI FLOW indication. [Step 1.d]
		• IF CCP SI FLOW can NOT be verified, THEN initiate Emergency Boration Flow per another method of ABN-107. [Step 1.e]

Operating Test : NRC	Scenario # 3	Event # 7, 8	Page 25 of 41
Event Description: Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure			

Time	Position	Applicant's Actions or Behavior

NOTE: TDM-201A/B provides equivalency values for boration from 2400 ppm source and a 7000 ppm source. A conservative approach is to borate the entire volume required for the condition from the 7000 ppm source once boration flow from the 2400 ppm source is terminated.

Time	Position	Applicant's Actions or Behavior
		• WHEN the RWST is isolated (1/1-LCV-112D AND 1/1-LCV-112E CLOSED) per the applicable ERG, THEN initiate Emergency Boration Flow per another method of ABN-107 until the desired amount of boration volume is injected (Reference Attachment 7 of ABN-107). [Step 1.f]

Examiner Note: EOP-0.0A, Attachment 2 steps performed by BOP are identified later in the scenario.

CAUTION: A Safety Injection actuation will affect normal egress from the Containment Building. Attachment 9 of this procedure provides instructions to evacuate personnel from the Containment during a Safety Injection actuation.

NOTE: Attachment 2 is required to be completed before FRGs are implemented.

Time	Position	Applicant's Actions or Behavior
	US/BOP	INITIATE Proper Safeguards Equipment Operation Per Attachment 2. [Step 5]

Examiner Note: The TDAWP may be used to feed all four SGs.

Operating Test :	NRC	Scenario #	3	Event #	7, 8	Page	26	of	41
Event Description:	Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure								

Time	Position	Applicant's Actions or Behavior
	RO	VERIFY AFW Alignment [Step *6]
		• VERIFY MDAFW 1-01 Pump – RUNNING feeding SG 1-01 and 1-02, MDAFW 1-02 Pump – TRIPPED, [Step 6.a]
		• TDAFW Pump RUNNING – feeding SG 1-03 and 1-04 [Step 6.b]
		• VERIFY AFW total flow – GREATER THAN 460 GPM. [Step 6.c]
		• VERIFY AFW valve alignment - PROPER ALIGNMENT. [Step 6.d]
	RO	VERIFY Containment Spray NOT Required: [Step *7]
		• VERIFY 1-ALB-2B, Window 1.8, CS ACT – NOT ILLUMINATED. [Step 7.a]
		• VERIFY 1-ALB-2B, Window 4.11, CNTMT ISOL PHASE B ACT – NOT ILLUMINATED. [Step 7.a]
		• VERIFY Containment pressure – LESS THAN 18.0 PSIG. [Step 7.a]
		• VERIFY Containment Spray Heat Exchanger Outlet Valves – CLOSED. [Step 7.b]
		• VERIFY Containment Spray Pumps – RUNNING. [Step 7.c]
CRITICAL TASK STATEMENT		**Initiate a MSLI or Manually close MSLI valves, due to failure to automatically isolate, prior to exiting EOP-0.0A, Reactor Trip or Safety Injection, or EOP-2.0, Faulted Steam Generator Isolation.**
	RO	CHECK if Main Steam lines should be ISOLATED: [Step *8]
		• VERIFY the following: [Step 8.a] • Containment pressure – GREATER THAN 6.0 PSIG. • Steam Line pressure – LESS THAN 610 PSIG.
CT-1		• VERIFY Main Steam Line Isolation – COMPLETE. [Step 8.b]
		• Determines Main Steam Isolation NOT complete with steam flow indicated on all four Steam Generators
		• Manually INITIATE a Main Steam Line Isolation. [Step 8.b RNO]
		• PLACE 1-HS-2337A, MSL ISOL MAN ACT / RESET in CLOSE position and VERIFY Main Steam Line Isolation Actuation <u>OR</u>
		• PLACE 1-HS-2337B, MSL ISOL MAN ACT / RESET in CLOSE position and VERIFY Main Steam Line Isolation Actuation <u>OR</u>

Operating Test : NRC	Scenario # 3	Event # 7, 8	Page 27 of 41
Event Description: Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure			

Time	Position	Applicant's Actions or Behavior
<u>Examiner Note</u>: Crew may manually initiate MSLI on Step 8 or Step 9, depending on timing of the event.		
CRITICAL TASK STATEMENT		**Initiate a MSLI or Manually close MSLI valves, due to failure to automatically isolate, prior to exiting EOP-0.0A, Reactor Trip or Safety Injection, or EOP-2.0, Faulted Steam Generator Isolation.**
	RO	CHECK RCS Temperature: [Step *9]
		• VERIFY RCS Average Temperature – STABLE AT OR TRENDING TO 557°F. [Step 9] - Less than 557°F
		• STOP dumping steam. [Step 9.a RNO]
		• IF cooldown continues, THEN REDUCE total AFW flow as necessary to minimize cooldown. [Step 9.b RNO] • Maintaining a minimum of 460 gpm UNTIL narrow range level greater than 43% (50% ADVERSE CONTAINMENT) in at least one SG. • As necessary to maintain SG levels WHEN narrow range level greater than 43% (50% FOR ADVERSE CONTAINMENT) in at least one SG • IF TDAFW pump is not required to maintain greater than 460 gpm flow, THEN stop TDAFW pump.
CT-1	US/RO	• IF cooldown continues, THEN CLOSE Main Steam Isolation Valves. [Step 9.c RNO]
		• Manually INITIATE a Main Steam Line Isolation. [Step 9.c RNO]
		• PLACE 1-HS-2337A, MSL ISOL MAN ACT / RESET in CLOSE position and VERIFY Main Steam Line Isolation Actuation <u>OR</u>
		• PLACE 1-HS-2337B, MSL ISOL MAN ACT / RESET in CLOSE position and VERIFY Main Steam Line Isolation Actuation <u>OR</u>

Operating Test : NRC	Scenario # 3	Event # 7, 8	Page 28 of 41
Event Description: Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure			

Time	Position	Applicant's Actions or Behavior
	RO	CHECK PRZR Valve Status: [Step 10]
		• VERIFY PRZR Safeties – CLOSED. [Step 10.a]
		• VERIFY Normal PRZR Spray Valves – CLOSED. [Step 10.b]
		• VERIFY PORVs – CLOSED. [Step 10.c]
		• VERIFY Power to at least 1 Block Valve – AVAILABLE. [Step 10.d]
		• VERIFY Block Valves – AT LEAST ONE OPEN. [Step 10.e]

<u>Examiner Note</u>: When EOP-0.0A, Step 11 is reached, RCS subcooling may not have lowered to the point where the RCPs must be tripped, however, this is a Foldout Page Action on Step 1 of EOP-0.0A, Attachment 1.A, and must be performed when conditions are met.

CRITICAL TASK STATEMENT	**Trip reactor coolant pumps within 5 minutes upon a loss of Subcooling per EOP-0.0A, Reactor Trip or Safety Injection OR EOP-1.0A, Loss of Reactor or Secondary Coolant.**

Subcooling less than 25°F Start Time: ____________

RCPs Tripped Stop Time: ____________

	RO	CHECK if RCPs Should Be Stopped: [Step 11]
		• VERIFY RCS subcooling – LESS THAN 25°F (55°F FOR ADVERSE CONTAINMENT). [Step 11.a]
		• VERIFY ECCS pumps - AT LEAST ONE RUNNING [Step 11.b]
		• CCP -OR- • SI pump
CT-2		• Stop all RCPs. [Step 11.c]

Operating Test :	NRC	Scenario #	3	Event #	7, 8	Page	29	of	41
Event Description:	Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure								

Time	Position	Applicant's Actions or Behavior
	RO/BOP	CHECK if Any SG is Faulted: [Step 12]
		• CHECK pressures in all SGs: [Step 12.a]
		• ANY SG PRESSURE DECREASING IN AN UNCONTROLLED MANNER -OR- • ANY SG COMPLETELY DEPRESSURIZED
		• Go to Step 13 [Step 12.a RNO a]
	RO/BOP	CHECK If SG Tubes Are Not Ruptured: [Step 13]
		• Condenser off gas radiation – NORMAL (COG-182, 1RE-2959) • Main steamline radiation – NORMAL (MSL-178 through 181, 1RE-2325 through 2328) • SG blowdown sample radiation monitor – NORMAL (SGS-164, 1RE-4200) • No Steam Generator level increasing in an uncontrolled manner
	RO/BOP	CHECK If RCS Is Intact: [Step 14]
		• Containment pressure – LESS THAN 1.3 psig • Containment recirculation sump levels – NORMAL • Containment radiation – NORMAL GRID 4
		• Go to EOP-1.0A, LOSS OF REACTOR OR SECONDARY COOLANT, Step 1

Examiner Note: **EOP-1.0A, Loss of Reactor or Secondary Coolant, steps begin here.**

CAUTION: Following a high energy line rupture inside containment, the operator should not rely upon steam generator water level indications in any depressurized steam generators.

Operating Test :	NRC	Scenario #	3	Event #	7, 8	Page	30	of	41
Event Description:	Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure								

Time	Position	Applicant's Actions or Behavior
		NOTE: As PRZR Temperature decreases the error on indicated PRZR level will increase. Attachment 2 may be used to determine actual PRZR level.
Examiner Note:		**When EOP-1.0A is entered, RCS subcooling may not have lowered to the point where the RCPs must be tripped, however, this is a Foldout Page Action on Step 1 of EOP-1.0A, Attachment 1.A, and must be performed when conditions are met.**
CRITICAL TASK STATEMENT		**Trip Reactor Coolant Pumps within 5 minutes upon a Loss of Subcooling per EOP-1.0A, Loss of Reactor or Secondary Coolant, Foldout Page.**
Subcooling less than 25°F Start Time: ____________		
RCPs Tripped Stop Time: ____________		
	RO	CHECK If RCPs Should Be Stopped: [Step 1]
		• RCS subcooling - LESS THAN 25°F (55°F FOR ADVERSE CONTAINMENT) [Step 1.a]
		• ECCS pumps - AT LEAST ONE RUNNING [Step 1.b] • CCP or • SI Pump
CT-2		• Stop all RCPs. [Step 1.c]
	RO/BOP	CHECK if Any Steam Generator Is Faulted: [Step 2]
		• Check pressures in all SGs [Step 2.a] • ANY SG PRESSURE DECREASINGIN AN UNCONTROLLED MANNER -OR- • ANY SG COMPLETELY DEPRESSURIZED
		• Go to Step 3 [Step 2.a RNO a]

Operating Test :	NRC	Scenario #	3	Event #	7, 8	Page	31	of	41	
Event Description:	Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure									

Time	Position	Applicant's Actions or Behavior
	BOP	CHECK Intact Steam Generator Levels: [Step *3]
		• Narrow range level – GREATER THAN 43% (50% FOR ADVERSE CONTAINMENT) [Step 3.a]
		• Control AFW flow to maintain narrow range level between 43% (50% FOR ADVERSE CONTAINMENT) and 60% [Step 3.b]
	BOP	CHECK Secondary Radiation NORMAL: [Step 4]
		• Condenser Off Gas radiation (COG-182, 1RE-2959)
		• Main steamline radiation (MSL-178 through 181, 1RE-2325 through 2328)
		• SG blowdown sample radiation monitor (SGS-164, 1RE-4200)
		CAUTION: If any PRZR PORV opens because of high PRZR pressure, Step 5b should be repeated after pressure decreases to less than the PORV setpoint.
	RO	CHECK PRZR PORVs and Block Valves: [Step *5]
		• Power to block valves – AVAILABLE [Step 5.a]
		• PORVs – CLOSED [Step 5.b]
		• Block valves - AT LEAST ONE OPEN [Step 5.c]
	US/RO	CHECK if ECCS Flow Should Be Reduced: [Step *6]
		• Secondary heat sink: [Step 6.a] • Total AFW flow to intact SGs - GREATER THAN 460 GPM -OR- • Narrow range level in at least one intact SG - GREATER THAN 43% (50% FOR ADVERSE CONTAINMENT)
		• RCS subcooling - GREATER THAN 25°F(55°F FOR ADVERSE CONTAINMENT) [Step 6.b]
		• Go to Step 7. OBSERVE CAUTIONS PRIOR TO STEP 7 [Step 6.b RNO b]

Operating Test : NRC	Scenario # 3	Event # 7, 8	Page 32 of 41
Event Description: Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure			

Time	Position	Applicant's Actions or Behavior
		CAUTION: If offsite power is lost after SI reset, manual action may be required to restart safeguards equipment.
		CAUTION: When time permits, Attachment 9 of EOP-0.0A, REACTOR TRIP OR SAFETY INJECTION should be performed to realign equipment after an SI signal has been reset.
	RO/BOP	RESET ESF Actuation Signals. [Step 7]
	RO/BOP	CHECK EDGs Running. [Step 7.a]
	RO/BOP	PLACE both EDG EMERG STOP/START handswitches in START. [Step 7.b]
	RO/BOP	RESET SI. [Step 7.c]
		• DEPRESS 1/1-SIRA, TRAIN A SI RESET pushbutton.
		• DEPRESS 1/1-SIRB, TRAIN B SI RESET pushbutton.
	RO/BOP	RESET SI Sequencers. [Step 7.d]
		• At SI Sequencer Train A Cabinet, DEPRESS SI SEQR RESET green pushbutton then PLACE ON/RESET toggle switch in RESET.
		• After ~ 2 seconds, PLACE ON/RESET toggle switch in ON.
		• At SI Sequencer Train B Cabinet, DEPRESS SI SEQR RESET green pushbutton then PLACE ON/RESET toggle switch in RESET.
		• After ~ 2 seconds, PLACE ON/RESET toggle switch in ON.
	RO/BOP	RESET Containment Isolation Phase A and Phase B. [Step 7.e]
		• DEPRESS 1/1-C1PARA, CNTMT ISOL – PHASE A RESET pushbutton.
		• DEPRESS 1/1-C1PARB, CNTMT ISOL – PHASE A RESET pushbutton.
		• DEPRESS 1/1-C1PBRA, CNTMT ISOL – PHASE B RESET pushbutton.

Operating Test :	NRC	Scenario #	3	Event #	7, 8	Page	33	of	41
Event Description:	Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure								

Time	Position	Applicant's Actions or Behavior
		• DEPRESS 1/1-C1PBRB, CNTMT ISOL – PHASE B RESET pushbutton.
	RO/BOP	RESET Containment Spray Signal. [Step 7.f]
		• DEPRESS 1/1-CSRA, TRAIN A CS RESET pushbutton.
		• DEPRESS 1/1-CSRB, TRAIN B CS RESET pushbutton.
		CAUTION: RCS pressure should be monitored. If RCS pressure decreases in an uncontrolled manner to less than 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT) the RHR pumps must be manually restarted to supply water to the RCS.
	US	CHECK If RHR Pumps Should Be Stopped: [Step *8]
		• Check RCS Pressure: [Step 8.a]
	RO/BOP	• VERIFY RCS pressure – GREATER THAN 325 psig (425 psig FOR ADVERSE CONTAINMENT). [Step 8.a.1)]
	RO/BOP	• VERIFY RCS pressure – STABLE OR INCREASING. [Step 8.a.2)]
	RO/BOP	• VERIFY RHR Pumps – RUNNING WITH SUCTION ALIGNED TO RWST. [Step 8.b]
	RO/BOP	• STOP RHR Pumps and PLACE in standby. [Step 8.c]
	RO/BOP	• RESET RHR Auto Switchover. [Step 8.d]
	US	CHECK RCS and SG Pressures: [Step 9]
		• Check RCS Pressure - STABLE OR DECREASING
		• Check Pressure in All SGs - STABLE OR INCREASING
	US/RO	CHECK If Diesel Generators Should Be Stopped: *[Step 10]
		• Verify AC safeguard busses - ENERGIZED BY OFFSITE POWER
	RO/BOP	• Stop any unloaded diesel generator by placing DG EMER STOP/START handswitch in STOP.

Operating Test :	NRC	Scenario #	3	Event #	7, 8	Page	34	of 41
Event Description:	Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure							

Time	Position	Applicant's Actions or Behavior
		NOTE: Verification of at least one flowpath from a RHR pump to the RCS via a SI pump or CCP is sufficient to verify cold leg recirculation capability.
	US	INITIATE Evaluation of Plant Status. [Step 11]
	RO/BOP	• Verify cold leg recirculation capability: [Step 11.a] • Verify the following conditions for the train related RHR pump(s): TRAIN A • RHR pump A – AVAILABLE • CCW to RHR pump A - AVAILABLE • 1/1-8811A, CNTMT SMP TO RHRP 1 SUCT ISOL VLV - AVAILABLE TRAIN B • RHR pump B – AVAILABLE • CCW to RHR pump B - AVAILABLE • 1/1-8811B, CNTMT SMP TO RHRP 2 SUCT ISOL VLV – AVAILABLE • Verify RHR valve(s) that supply SI pumps and CCPs – AVAILABLE • 1/1-8804A, RHRP 1 TO CCP SUCT VLV • 1/1-8804B, RHRP 2 TO SIP SUCT VLV
	RO/BOP	• Check auxiliary building and safeguards building radiation – NORMAL [Step 11.b] • Check PC-11 monitors (GRID 4) – NORMAL • Notify Radiation Protection to take local radiation surveys.
		• Notify Chemistry to obtain RCS samples to assist in determining extent of the accident. [Step 11.c]
		• Evaluate plant equipment: [Step 11.d] • Consult Plant Staff to determine equipment that should be available or started to assist in recovery.
	US	CHECK if RCS Cooldown and Depressurization Is Required: [Step 12]
		• RCS pressure - GREATER THAN 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT) [Step 12.a]
		• Go to EOS-1.2A, POST LOCA COOLDOWN AND DEPRESSURIZATION, Step 1. [Step 12.b]

Operating Test :	NRC	Scenario #	3	Event #	7, 8	Page	35	of	41
Event Description:	Ejected Rod, Steam leak downstream of MSIVs, MSLI Failure								

Time	Position	Applicant's Actions or Behavior

When the crew transitions to EOS-1.2A, POST LOCA COOLDOWN AND DEPRESSURIZATION, or at the lead Examiners discretion, Terminate the scenario

Operating Test :	NRC	Scenario #	3	Event #	Att 2	Page	36	of	41
Event Description:	EOP-0.0A, Attachment 2								

Time	Position	Applicant's Actions or Behavior
Examiner Note: **These steps are performed by the BOP per EOP-0.0A, Attachment 2.**		
CAUTION: If during performance of this procedure the SI sequencer fails to complete its sequence, Attachment 3 may be used to ensure proper equipment operation for major equipment.		
	BOP	VERIFY SSW Alignment: [Step 1]
		• VERIFY SSW Pumps – RUNNING. [Step 1.a]
		• VERIFY Diesel Generator Cooler SSW return flow. [Step 1.b]
	BOP	VERIFY Safety Injection Pumps – RUNNING. [Step 2]
	BOP	VERIFY Containment Isolation Phase A – APPROPRIATE MLB LIGHT INDICATION (RED WINDOWS). [Step 3]
	BOP	VERIFY Containment Ventilation Isolation – APPROPRIATE MLB LIGHT INDICATION (GREEN WINDOWS). [Step 4]
	BOP	VERIFY CCW Pumps – RUNNING. [Step 5]
	BOP	VERIFY RHR Pumps – RUNNING. [Step 6]
	BOP	VERIFY Proper CVCS Alignment: [Step 7]
		• VERIFY CCPs – RUNNING. [Step 7.a]
		• VERIFY Letdown Relief Valve Isolation: [Step 7.b]
		• VERIFY Letdown Orifice Isolation Valves – CLOSED. [Step 7.b.1)]
		• VERIFY Letdown Isolation Valves 1/1-LCV-459 & 1/1-LCV-460 – CLOSED. [Step 7.b.2)]

Operating Test : NRC	Scenario # 3	Event # Att 2	Page 37 of 41
Event Description: EOP-0.0A, Attachment 2			

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY ECCS flow: [Step 8]
		• CCP SI flow indicators – CHECK FOR FLOW. [Step 8.a]
		• RCS pressure – LESS THAN 1700 PSIG (1800 PSIG FOR ADVERSE CONTAINMENT). [Step 8.b]
		• SIP discharge flow indicator – CHECK FOR FLOW. [Step 8.c]
		• RCS pressure – LESS THAN 325 PSIG (425 PSIG FOR ADVERSE CONTAINMENT). [Step 8.d]
		• Go to Step 9 of this attachment. [Step 8.d RNO d]
	BOP	VERIFY Feedwater Isolation Complete: [Step 9]
		• Feedwater Isolation Valves – CLOSED.
		• Feedwater Isolation Bypass Valves – CLOSED.
		• Feedwater Bypass Control Valves – CLOSED.
		• Feedwater Control Valves – CLOSED.
	BOP	VERIFY Diesel Generators – RUNNING. [Step 10]
	BOP	VERIFY Monitor Lights for SI Load Shedding on 1-MLB-9 and 1-MLB-10 – LIT. [Step 11]
NOTE: The MLB indication for SI alignment includes components which may be in a different alignment to support unit conditions. MSIVs, MSLs BEF MSIV D/POT ISOL, TDAFWP STEAM SUPPLIES, TDAFWP RUN, MDAFWP FLO CTRL VLVs and TDAFWP FLO CTRL VLVs may be exceptions to the expected MLB indication.		
	BOP	VERIFY Proper SI alignment – PROPER MLB LIGHT INDICATION. [Step 12]

Operating Test :	NRC	Scenario #	3	Event #	Att 2	Page	38 of 41
Event Description:	EOP-0.0A, Attachment 2						

Time	Position	Applicant's Actions or Behavior

NOTE: Any previously removed missile shield(s) that affects the Control Room, Auxiliary, Safeguards or Fuel Building pressure boundary is required to be restored upon initiation of a Safety Injection Signal.

NOTE: When the SI sequencer has timed out, the Reactor Makeup Water Pump with its handswitch in Auto will restart.

Time	Position	Applicant's Actions or Behavior			
	BOP	VERIFY Components on Table 1 are Properly Aligned. [Step 13]			
		Location	Equipment	Description	Condition
		CB-03	X-HS-5534	H2 PRG SPLY FN 4	STOPPED
		CB-03	X-HS-5532	H2 PRG SPLY FN 3	STOPPED
		CB-04	1/1-8716A	RHRP 1 XTIE VLV	OPEN
		CB-04	1/1-8716B	RHRP 2 XTIE VLV	OPEN
		CB-06	1/1-8153	XS LTDN ISOL VLV	CLOSED
		CB-06	1/1-8154	XS LTDN ISOL VLV	CLOSED
		CB-07	1/1-RTBAL	RX TRIP BKR	OPEN
		CB-07	1/1-RTBBL	RX TRIP BKR	OPEN
		CB-07	1/1-BBAL	RX TRIP BYP BKR	OPEN/DEENERGIZED
		CB-07	1/1-BBBL	RX TRIP BYP BKR	OPEN/DEENERGIZED
		CB-08	1-HS-2397A	SG 1 BLDN HELB ISOL VLV	CLOSED
		CB-08	1-HS-2398A	SG 2 BLDN HELB ISOL VLV	CLOSED
		CB-08	1-HS-2399A	SG 3 BLDN HELB ISOL VLV	CLOSED
		CB-08	1-HS-2400A	SG 4 BLDN HELB ISOL VLV	CLOSED
		CB-08	1-HS-2111C	FWPT A TRIP	TRIPPED
		CB-08	1-HS-2112C	FWPT B TRIP	TRIPPED
		CB-09	1-HS-2490	CNDS XFER PUMP	STOPPED (MCC deenergized on SI)
		CV-01	X-HS-6181	PRI PLT SPLY FN 17 & INTK DMPR	STOPPED/DEENERGIZED

Operating Test : NRC	Scenario # 3	Event # Att 2	Page 39 of 41
Event Description: EOP-0.0A, Attachment 2			

Time	Position	Applicant's Actions or Behavior

	CV-01	X-HS-6188	PRI PLT SPLY FN 18 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6195	PRI PLT SPLY FN 19 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6202	PRI PLT SPLY FN 20 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6209	PRI PLT SPLY FN 21 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6216	PRI PLT SPLY FN 22 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6223	PRI PLT SPLY FN 23 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-6230	PRI PLT SPLY FN 24 & INTK DMPR	STOPPED/DEENERGIZED
	CV-01	X-HS-3631	UPS & DISTR RM A/C FN 1 & BSTR FN 42	STARTED
	CV-01	X-HS-3632	UPS & DISTR RM A/C FN 2 & BSTR FN 43	STARTED
	CV-01	1-HS-5600	ELEC AREA EXH FN 1	STOPPED/DEENERGIZED
	CV-01	1-HS-5601	ELEC AREA EXH FN 2	STOPPED/DEENERGIZED
	CV-01	1-HS-5602	MS & FW PIPE AREA EXH FN 3 & EXH DMPR	STOPPED/DEENERGIZED
	CV-01	1-HS-5603	MS & FW PIPE AREA EXH FN 4 & EXH DMPR	STOPPED/DEENERGIZED
	CV-01	1-HS-5618	MS & FW PIPE AREA SPLY FN 17	STOPPED/DEENERGIZED
	CV-01	1-HS-5620	MS & FW PIPE AREA SPLY FN 18	STOPPED/DEENERGIZED
	CV-03	X-HS-5855	CR EXH FN 1	STOPPED/DEENERGIZED
	CV-03	X-HS-5856	CR EXH FN 2	STOPPED/DEENERGIZED
	CV-03	X-HS-5731	SFP EXH FN 33	STOPPED/DEENERGIZED
	CV-03	X-HS-5733	SFP EXH FN 34	STOPPED/DEENERGIZED
	CV-03	X-HS-5727	SFP EXH FN 35	STOPPED/DEENERGIZED
	CV-03	X-HS-5729	SFP EXH FN 36	STOPPED/DEENERGIZED

Examiner Note: The next four steps would be performed on Unit 2.

Operating Test :	NRC	Scenario #	3	Event #	Att 2	Page	40	of	41
Event Description:	EOP-0.0A, Attachment 2								

Time	Position	Applicant's Actions or Behavior

		CB-03	2-HS-5538	AIR PRG EXH ISOL DMPR	CLOSED
		CB-03	2-HS-5539	AIR PRG EXH ISOL DMPR	CLOSED
		CB-03	2-HS-5537	AIR PRG SPLY ISOL DMPR	CLOSED
		CB-03	2-HS-5536	AIR PRG SPLY ISOL DMPR	CLOSED
	BOP	NOTIFY Unit Supervisor attachment instructions complete AND to IMPLEMENT FRGs as required.			
EOP-0.0A, Attachment 2 steps are now complete.					

```
;Initial Conditions

;MSL Isolation Failure
IMF SS02A1 f:1
IMF SS02A2 f:1

;TPCW Pmp Trip
IMF TP07B f:1
IMF TP06A f:1 k:2

;TK-130 Fails to 0% Demand-Manual Reopens valve, TCV129 not diverted
IOR AICVTK130 f:10 d:60 k:3
{AOCVTK130.Value=0}IMF CV05 f:0
{AOCVTK130.Value=0}IOR LOCVTK130_1 f:1
{AOCVTK130.Value=0}IOR LOCVTK130_2 f:0
{AOCVTK130.Value=0}IOR DICVTK130_2 f:1
{AOCVTK130.Value=0}IOR DICVTK130_4 f:1
{DICVTK130_2.Value=1}DMF CV05
{DICVTK130_2.Value=1}DOR LOCVTK130_1
{DICVTK130_2.Value=1}DOR LOCVTK130_2
{DICVTK130_2.Value=1}DOR DICVTK130_2
{DICVTK130_2.Value=1}DOR DICVTK130_4
{DICVTK130_1.Value=1}IMF CV05 f:0
IOR DICVHS129 f:2 d:60 k:3
aet TCV129 fail

;PCV456 Fail at 25%
IMF RX08B f:2500 k:4
IMF RX16B f:25 d:5 k:4

;AFWP 2 trip
IMF FW24B f:1 k:5

;Seismic event
IRF AN2A_02 f:4 k:6
IRF AN2A_03 f:4 k:6

;Ejected rod, stuck rod
IMF RD09B6 f:228 d:120 k:6
IMF RD04B6 f:228 d:120 k:6
IMF RD04F6 f:168 d:120 k:6
IMF RC19C f:1500 d:120 k:6

;Modify RCS Leak
{DIRPSIA2.Value=1} MMF RC19C f:1750 r:60

;Steam Leak
IMF MS02 f:2e+006 r:120 d:270 k:6

;PRZR PORV Block Valve Breaker
IRF RCR24 f:0 k:11
```

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

INTEGRATED PLANT OPERATING PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS hm / 2day LATEST PCN/EFFECTIVE DATE 1 / 6/21/16 1200

LEVEL OF USE:
CONTINUOUS USE

QUALITY RELATED

PLANT STARTUP
FROM HOT STANDBY

PROCEDURE NO. IPO-002A

REVISION NO. 21

EFFECTIVE DATE: 8-18-15 1200

PREPARED BY (Print): J. D. Stone EXT: 0564

TECHNICAL REVIEW BY (Print): EDITORIAL REVISION EXT: NA

APPROVED BY: Joe Ricks for D. McGaughey DATE: 8/11/15
DIRECTOR, OPERATIONS

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-002A
PLANT STARTUP FROM HOT STANDBY	REVISION NO. 21 CONTINUOUS USE	PAGE 2 OF 98

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PLANT STARTUP FROM HOT STANDBY	REVISION NO. 21 CONTINUOUS USE	PAGE 3 OF 98

1.0 [C] APPLICABILITY

This procedure describes steps for Reactor startup and plant operation up to approximately 2% Reactor power (from Hot Standby MODE 3 to MODE 2). This procedure is a trigger procedure for Technical Specification Surveillance Requirements (TS SR) 3.1.4.3, 3.1.6.1, 3.3.1.8.2b, 3.3.1.8.4, 3.3.1.8.5, 3.4.13.1, 3.4.13.2, 3.4.14.1, 3.7.2.1, and Offsite Dose Calculation Manual (ODCM) 4.11.2.1.1.2 and 4.11.2.1.1.3. This procedure captures and reflects the recommendations of SOER 07-01

2.0 PREREQUISITES

2.1 Approval has been granted by the Operations Manager or Shift Operations Manager to prepare for a Reactor startup. wm / 2day
Initials Date

2.2 The plant is in Hot Standby with all RCS loop temperatures greater than 500°F. wm / 2day
Initials Date

2.3 The shutdown margin is within the limits of the COLR per OPT-301. wm / 2day
Initials Date

2.4 The Main Turbine is on turning gear per SOP-404A wm / 2day
Initials Date

2.5 At least one Main Feedwater Pump turbine is on turning gear or allowed to windmill per SOP-302A wm / 2day
Initials Date

2.6 Main condenser vacuum is established (greater than 25 in. Hg) and the Steam Dumps are in the Steam Pressure mode of control. wm / 2day
Initials Date

2.7 At least one Condensate Pump is operating. wm / 2day
Initials Date

2.8 A sufficient number of Circulating Water Pumps are in service to optimize efficiency per TDM-310A wm / 2day
Initials Date

2.9 Both Motor Driven Auxiliary Feedwater Pumps are available to maintain Steam Generator levels. wm / 2day
Initials Date

2.10 RCS pressure is being maintained between 2220 psig and 2250 psig. wm / 2day
Initials Date

2.11 Normal charging and letdown have been established and are maintaining programmed Pressurizer level. wm / 2day
Initials Date

2.12 IF startup is following a Forced Outage,
THEN
ENSURE Attachment 8, Forced Outage Checklist, has been completed. NA /
Initials Date

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-002A
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2.13 CONTACT Chemistry to verify RCS Chemistry, and Lithium *, supports reactor startup.

		Absolute		
•	Chloride	≤ 0.15 ppm	0.01	ppm
•	Fluoride	≤ 0.15 ppm	0.01	ppm
•	Dissolved Oxygen	≤ 0.10 ppm	0.02	ppm
•	Dissolved Hydrogen	≥ 15 cc/Kg	20	cc/Kg
•	Lithium *	≥ 1.0 ppm	1.2	ppm

* Per Lithium Control Program in CHM-120.

Chemist
Chemist contacted

AN / 12day
Initials Date

2.14 NOTIFY Chemistry of intent to perform a Reactor Startup and ENSURE sampling requirements of ODCM 4.11.2.1.1.2 and 4.11.2.1.1.3 are initiated.

w / 12day
Initials Date

2.15 All Reactor Coolant Pumps are in service.

w / 12day
Initials Date

2.16 Any special tests required by the Operations Manager, prior to start-up, have been completed.

w / 12day
Initials Date

2.17 A Containment entry has been made to visually inspect Containment for any abnormal conditions and identify any leaks for VT-2 Post Work Series 70 Steps OR that may affect OPT-303. Any observed leakage shall be documented on form OPT-303-2. In addition, adverse conditions other than and including RCS Leakage should be documented per STA-606.

w / 12day
Initials Date

2.18 ENSURE all check valve leak rate testing has been performed per OPT-611A, OPT-612A, OPT-613A, OPT-614A, OPT-615A and OPT-616A (TS SR 3.4.14.1).

w / 12day
Initials Date

[C]
2.19 IF ALL RCPs are stopped,
THEN
INITIATE compensatory measures required by OWI-104-56.

NA /
Initials Date

2.20 IF a Trainee will be used to perform the Reactor Startup,
THEN
Shift Operations Manager approval has been obtained
AND
the requirements of ODA-102 are met.

N/A /
Initials Date

2.21 IF Start up is following an RCS cooldown,
THEN
an inspection of the Loop Rooms AND the Pressurizer Cubicle should be performed prior to Mode 2.

m / 2day
Initials Date

3.0 PRECAUTIONS

3.1 Administrative

3.1.1 Work activities in the Nuclear Instrumentation areas could adversely affect indication. All welding should be stopped in the Control, Auxiliary and Safeguards buildings while the Reactor Trip breakers are closed and the Reactor is in the Source Range.

3.1.2 During the approach to criticality and prior to reaching the point of adding heat, positive reactivity shall not be simultaneously inserted by boron dilution and control rod withdrawal.

3.1.3 Criticality should not be achieved by boron dilution, except during initial startup following a refueling.

3.1.4 The further the control rods are into the core when criticality is achieved, the more rod worth (reactivity addition) there will be when rod movement is initiated.

3.1.5 During the initial startup following a refueling, Core Performance Engineering procedures will be guiding the use of this procedure.

3.1.6 A plant vent grab sample shall be analyzed following shutdown, startup or thermal power change ≥15% of Rated Thermal Power within 1 hour, if analysis of the primary coolant shows dose equivalent I-131 concentration has increased by a factor of 3 or the noble gas monitor shows effluent activity has increased by a factor of 3 (ODCM 4.11.2.1.1.3).

3.1.7 Prior to opening the SG ARVs, Chemistry shall be notified to determine if a release permit is required per STA-603.

3.1.8 EXERCISE caution when opening the SG ARV or Steam Dump Valves in Auto or Manual. A rate compensated steam line low pressure Safety Injection can result from opening the valves too quickly.

3.1.9 The following cautions should be observed when the Main Steam Isolation Bypass Valves are opened after heatup:

A. AVOID large steam pressure drops to prevent a rate compensated steam line low pressure Safety Injection from occurring.

B. Steam lines should be heated up slowly.

C. Steam line drains should be checked for proper operation.

[C] 3.1.10 Reactor operation at low-power levels for extended periods of time is discouraged. Station management shall carefully consider the risk of operating during off-normal plant conditions such as low-power operation, develop appropriate contingencies, and provide training to operators before the evolution. Guidance should identify potential problems that could be encountered such as the possibility that the core may become subcritical and predefines conditions under which operators should shut down or manually scram the reactor.

3.1.11 STA-735 describes the Fuel Integrity Program. This program includes additional Radiochemistry sampling requirements for the following:

A. Initial Startup following a refueling - every 3-4 hours beginning at zero percent and continuing for at least 24 hours after full power is achieved.

B. Startup from the shutdown condition during a cycle - 2-6 hours after criticality, then once every 24 hours.

C. Shutdown - 2-6 hours after initiation of Reactor shutdown, then once per 24 hours.

D. Power condition:

- Daily for I, Cs and Br for first 4 weeks, 3 times per week thereafter.
- Three times per week for Xe, Kr and total activity for the first 4 weeks, once per week thereafter.
- Once per week for demineralizer efficiency.

3.1.12 Operational events which could affect fuel performance shall be reported to Core Performance Engineering. Examples of such events include: rapid RCS cooldowns or heatups, unusual control rod movements, unusual Nuclear Instrumentation (NI) indications, etc.

3.1.13 To determine plant MODE with NO Reactor Coolant Pumps operating, USE the Core Exit Thermocouple indicating the highest temperature. To determine plant MODE with Reactor Coolant Pumps operating, USE the Loop T_{HOT} indicating the highest temperature.

3.1.14 Performance of this procedure is considered as an Infrequently Performed Evolution which should be implemented per OWI-107.

3.1.15 A controller may be placed in MANUAL during the performance of this procedure if the Unit Supervisor is notified and the requirements of ODA-401 are met.

3.2 Equipment

3.2.1 Criticality must be anticipated anytime the control rods are being withdrawn, boron dilution operations are in progress or when RCS temperature is being changed.

3.2.2 If the source range count rate increases by a factor of two during any step involving a boron concentration change, except for dilution to criticality for initial startup following refueling, the operation must be stopped immediately and suspended until the reason for the increased count rate is determined. Core Performance Engineering should be notified if the reason cannot be determined.

3.2.3 An ECC shall be performed prior to withdrawing Shutdown Banks to ensure the Reactor will remain subcritical with Shutdown Banks withdrawn.

3.2.4 The Shutdown Rods shall be withdrawn prior to any RCS boron concentration dilution WHEN boron concentration is less than the boron concentration specified by the ECC.

3.2.5 DO NOT continue to insert Control Bank A rods in manual when indication is at the Control Bank Offset position. This will cause rod sequencing inaccuracy.

3.2.6 Steam shall not be admitted to the Main Turbine or the Main Feedwater Pump Turbines until Reactor power is greater than 1%.

[C] 3.2.7 When changing the RCS boron concentration, Pressurizer heaters and spray should be utilized to minimize the differential between the Pressurizer and RCS loop boron concentrations to approximately 50 ppm or less.

3.2.8 When any 345KV breaker is opened, the associated disconnects should be opened within one hour to prevent overheating the windings on the metering transformers.

3.2.9 A Reactor Coolant Pump shall not be started while in MODE 2 or MODE 1 operation.

3.2.10 Shutdown and Control Rod Banks shall be withdrawn and inserted in their prescribed sequence. Overlap of Control Rod Banks shall be 107 steps. If Control Rod Banks overlap is not 107 steps, rod withdrawal should be stopped and the problem investigated.

3.2.11 REFER to TDM-102A for the current Control Bank Offset (CBO) and Full Out Position (FOP). Control bank overlap will remain at 107 steps at all times.

3.2.12 The Turbine Driven Auxiliary Feedwater Pump should not be used during normal plant operation, except for surveillance testing, due to Environmental Qualification and High Energy Line Break design constraints which require the steam supply piping to be depressurized during normal plant operation.

3.2.13 Any time the Main Feed Pumps are not in operation, the FWIBVs are required to be isolated by closing the upstream manual isolation valves to prevent inadvertent backflow from the SGs.

[C] 3.2.14 Plant modifications, such as changing the physical location of nuclear detectors or modifying existing nuclear detectors and changing the core loading pattern, can affect Nuclear Instrumentation indication of Reactor power. Alternate indication of Reactor power level, such as core delta temperature or steam temperature (TDM-301A), should be used to verify accuracy of nuclear instrumentation and power level indication during startup.

3.2.15 <u>IF</u> main feedwater back leakage is indicated by abnormally high AFW pump discharge piping temperature, <u>OR</u> by high AFW temperature indication,
<u>THEN</u>
REFER to ABN-305.

3.2.16 Any time temperature through the upper penetration is >250°F, the time shall be logged in the Unit Log. The maximum time allowable >250°F is 24 hours. Temperature should be restored to less than 250°F within 24 hours.
<u>IF</u> temperature >250°F for 24 hours,
<u>THEN</u>
System Engineering should be contacted. REFER to ABN-302.

4.0 LIMITATIONS/NOTES

4.1 Limitations

4.1.1 A minimum of two Source Range channels shall be operable in MODE 2 below the P-6 setpoint (TS 3.3.1.5).

4.1.2 As a minimum, two Source Range Neutron Flux Monitors (two Westinghouse or two Gamma-Metrics) shall be OPERABLE, each with continuous visual indication in the Control Room per ODA-308-3.9.0. (TS 3.9.3, TR 13.3.32)

4.1.3 In MODE 1 (below the P-10 setpoint) and MODE 2 (above the P-6 setpoint), a minimum of two Intermediate Range channels shall be operable (TS 3.3.1.4).

4.1.4 In MODES 1 and 2, a minimum of four Power Range channels shall be operable (TS 3.3.1.2a, 3.3.1.2b, and 3.3.1.3).

4.1.5 In MODE 3, with the Rod Control System capable of rod withdrawal, a minimum of two Reactor Coolant loops shall be operable and in operation (TS 3.4.5).

4.1.6 In MODE 3, with the Rod Control System NOT capable of rod withdrawal, a minimum of two Reactor Coolant loops shall be operable and at least one Reactor Coolant loop shall be in operation (TS 3.4.5).

4.1.7 In MODES 1 and 2, four Reactor Coolant loops shall be operable and in operation (TS 3.4.4).

4.1.8 In MODE 1 and in MODE 2 with Keff $\geq$1.0, each operating RCS loop temperature (Tave) shall be greater than or equal to 551°F (TS 3.4.2).

4.1.9 In MODE 2 with Keff <1.0, and MODES 3, 4, and 5, SDM shall be within the limits provided in the COLR (TS 3.1.1).

4.1.10 During startup and power operations moderator temperature coefficient (MTC) shall be maintained within limits specified in the COLR.
<u>IF</u> during low power physics testing MTC is determined to be more positive than the upper limit of TS Figure 3.1.3-1,
<u>THEN</u>
control rods shall be maintained below the withdrawal limits established in NUC-116-2 (TS 3.1.3).

4.1.11 Control Banks shall be within the insertion, sequence, and overlap limits specified in the COLR (TS 3.1.6).

4.1.12 <u>IF</u> a RCS heatup is in progress,
<u>THEN</u>
the SGs shall NOT be drained below 60% narrow range level when the RCS temperature >200°F. (FDA-2013-000186-01)

4.1.13 FWIV temperature should be verified $\geq$90°F at all times. If temperature is <90°F REFER to TRM 13.7.38.

[C] 4.1.14 IF NO RCPs are operating in MODEs 3, 4, or 5,
THEN
dilution paths should be isolated per OWI-104-56 OR PERFORM the compensatory actions of OWI-104-56.

4.1.15 Do not exceed a startup rate of 1 dpm.

4.1.16 Performance of an RCS water inventory balance shall be performed within 12 hours after achieving a steady state condition per OPT-303 and at least once per 72 hours thereafter during steady state conditions (TS SR 3.4.13.1, 3.4.13.2).

4.1.17 Automatic start of the Motor Driven AFW Pumps on the trip of both Main Feedwater Pumps is required Operable in MODES 1 and 2 (TS 3.3.2, Table 3.3.2-1 Function 6.g) to ensure a supply of water to at least one SG for heat sink availability. In MODE 1 or 2 with one MFP supplying flow to the SGs (AFW pumps stopped), the second MFP must remain tripped or have the trip oil pressure switches isolated to ensure compliance with TS 3.3.2. (CR-2010-000638)

4.2 Notes

4.2.1 In the event plant conditions require a delay during some part of this procedure, the Shift Manager shall retain this procedure until it is continued or terminated. If this procedure is terminated prior to completion, the Shift Manager shall note the reason, time and date of termination on this procedure.

4.2.2 During a routine Reactor startup, three licensed Reactor Operators should be present in the affected Unit Control Room. Typically, one RO should be assigned duties at the Reactor Control System, one at the SG Water Level Control System, and during Turbine Generator rollup, the third RO should be at the Main Turbine Controls. When another RO is available, he should perform all checks required until criticality, silence and respond to alarms and operate equipment at the NIS and Ventilation panels. If an Operator is used to respond to alarms, all board Operators are to remain aware of alarm conditions and periodically scan the Main Control Boards. The Shift Manager may reduce the manpower requirements based on plant conditions.

4.2.3 A systematic step-by-step review and implementation of the procedure instructions (steps, notes and cautions) is required to implement this IPO. The Bubble Chart on Attachment 7 gives guidance as to what sequence the IPO steps may be performed when proceeding from MODE 3 to MODE 2.

4.2.4 During implementation of this IPO, the SRO directing IPO activities is expected to **initial AND date** steps once they have been performed, and notes and cautions once they have been evaluated for the applicable evolution.

Initialing the steps, notes and cautions provides a place-keeping aid to ensure the information has been reviewed and disseminated to the Shift Operations crew.

Providing a date for the steps, notes and cautions provides a time-frame with respect to when the instruction was completed, which may benefit planning an evolution that is being resumed following a time delay.

IPO steps reverified/reperformed following a delay where the step(s) had previously been signed off should be redated.

4.2.5 Any step which can not be performed in part or in its entirety due to equipment conditions shall be documented in the remarks section at the end of this procedure. The deviation shall not violate any Technical Specification limitation.

4.2.6 Experience has shown that on a sudden increase in oil system flow, (i.e., when FWP speed is raised quickly) the standby MOP may start. (EV-CR-1999-001167-1)

5.4 Increasing Reactor Power to Approximately 2% Following Reactor Startup and Establishing Main Feedwater Flow to the SGs

CAUTION:
- The preferred methods to maintain Reactor Power and temperature prior to Turbine Generator synchronization are use of Steam Dumps and SG Blowdown Flow. Steam Dump operation and Main Steam Line Drain flow affect LP Turbine casing ΔT, which should be monitored prior to synchronization.
- If LP Turbine casing ΔT approaches limits prior to synchronization, a reduction in Steam Dump operation may be required, and Main Steam Line drain flow should also be limited.
- The preferred method, to reduce Steam Dump Operation and Main Steam Line drain flow, is maintaining maximum SG Blowdown flow.
- SG Atmospherics should not be routinely used to minimize Steam Dump operation.

NOTE:
- The verification of Power Range response and reaching the point of adding heat can be used to ensure proper Nuclear Instrumentation response.
- Intermediate Range should be monitored and/or trended to provide alternate indication of how power is trending. At low power, Power Range Instruments may not give an accurate trend of actual power.

5.4.1 INCREASE Reactor power to approximately 2% by performing the following:

A. IF the Main Steam Isolation Valves are closed,
THEN
PERFORM the following:

1) IF required by Chemistry,
THEN
INITIATE a non-routine release permit per STA-603. ______/______ Initials Date

2) SLOWLY adjust the desired SG ATMOS RLF VLV CTRL setpoint to maintain approximately 1092 psig per TDM-501A. ______/______ Initials Date

3) ENSURE ALL SG ATMOS RLF CTRLs are in AUTO. ______/______ Initials Date

B. ESTABLISH a startup rate of approximately 0.5 dpm to increase Reactor power to approximately 2%. ______/______ Initials Date

5.4.1 C. Gradually REDUCE startup rate to attain approximately 0.2 dpm as the Intermediate Range channels approach 3X10^{-6} amps.

_____/_____
Initials Date

D. VERIFY the Power Range channels begin to respond when the Intermediate Range Channels are between 3X10^{-6} amps and 5X10^{-6} amps.

_____/_____
Initials Date

[C] E. IF the Steam Dumps are available AND RCS TAVE is approximately 557°F, THEN VERIFY the following:

- ☐ • Steam Dump operation begins
- ☐ • 1-PI-507, MS HDR PRESS is maintained at approximately 1092 psig

_____/_____
Initials Date

F. IF the Steam Dumps are NOT available AND RCS TAVE is approximately 557°F, THEN VERIFY the following:

- ☐ • SG ARVs begin to open
- ☐ • Main Steam line pressures are maintained at approximately 1092 psig

_____/_____
Initials Date

G. VERIFY 1-PCIP, 3.6, TAVE LO LO P-12 is OFF.

_____/_____
Initials Date

H. MAINTAIN Reactor power between 2% and 3%.

_____/_____
Initials Date

I. IF desired, COMMENCE main turbine startup preps in IPO-003A, while continuing with this procedure.

_____/_____
Initials Date

5.4.2 ADJUST Auxiliary Feedwater flow as necessary to maintain SG levels between 60% and 75%.

_____/_____
Initials Date

CAUTION: Exercise caution when opening the Main Steam Isolation Bypass Valves. A rate compensated steam line low pressure Safety Injection can result from opening the valves too quickly.

[C] 5.4.3 IF MSIVs are NOT open,
THEN
OPEN the MSIVs and heatup the Main Steam lines as follows:

CAUTION:
- Only ONE MSIBV shall be opened at any time.
- With one MSIBV open, ONLY the corresponding MSIV may be opened.
- During MODE 2, 3 or 4, one MSIV bypass valve may be opened provided the other three bypass valves are locked closed AND their associated MSIVs are closed.
- Operating MSIBVs after an extended outage OR under conditions of low decay heat generation may result in an excessive cooldown of the RCS.
- When opening MSIBVs, use no larger than ¼ turn increments to allow a controlled heatup without excessive RCS cooldown.

NOTE: OPT-509A should be reviewed prior to opening the MSIVs to determine if an MSIBV requires stroke testing. When the surveillance is required, the test will be performed in conjunction with the following steps.

A. IF Attachment 7 to IPO-001A was not completed during heat-up to MODE 3,
THEN
ENSURE Attachment 4 to this procedure is complete

_____ / _____
Initials Date

B. ENSURE N_2 has been isolated to the feedwater heaters per SOP-511.

_____ / _____
Initials Date

C. ENSURE 1-PK-507, STM DMP PRESS CTRL in MANUAL AND 0% demand.

_____ / _____
Initials Date

D. ENSURE ALL MSIBVs are closed AND locked.

_____ / _____
Initials Date

NOTE:
- Opening MSIBVs may cause RCS temperature to decrease.
- One MSIBV is selected for use in warming Main Steam Lines (MSIBV to be tested per OPT-509A, if required, should be the selected MSIBV).

5.4.3 E. UNLOCK AND OPEN ONE MSIBV less than ¼ turn and RECORD:

- ☐ • MSIBV 1-HV-__________
- ☐ • If required by Step 5.4.3.G MSIBV 1-HV-__________
- ☐ • If required by Step 5.4.3.G MSIBV 1-HV-__________
- ☐ • If required by Step 5.4.3.G MSIBV 1-HV-__________

_____/_____
Initials Date

NOTE: The following are available to monitor Main Steam Line Heatup on CB-08 (Plant Computer Points are shown in parenthesis). Equivalent valid Control Board or Plant Computer points may be substituted as desired:

- 1-PI-507, MS HDR PRESS (P5472A, MSL HEADER PRESS)
- 1-PI-514A, MSL 1 PRESS CHAN I (P6400A, MSL 1 PRESS CHAN I)
- 1-PI-524A, MSL 2 PRESS CHAN I (P6420A, MSL 2 PRESS CHAN I)
- 1-PI-534A, MSL 3 PRESS CHAN I (P6440A, MSL 3 PRESS CHAN I)
- 1-PI-544A, MSL 4 PRESS CHAN I (P6460A, MSL 4 PRESS CHAN I)
- 1-TI-2329, MSL 1 TEMP (T2611A, MSL 1 TEMP)
- 1-TI-2330, MSL 2 TEMP (T2612A, MSL 2 TEMP)
- 1-TI-2331, MSL 3 TEMP (T2613A, MSL 3 TEMP)
- 1-TI-2332, MSL 4 TEMP (T2614A, MSL 4 TEMP)
- TSE #1 ADMISSION DISPLAY POINT 1 1-RA01T021

F. WHEN MSL TEMP is stable,
THEN
COMPARE MSL PRESS to MS HDR PRESS
AND
PERFORM the following as required:

1) IF Δp ≤ 15 psid
THEN
GO TO Step 5.4.3 G.

_____/_____
Initials Date

2) IF Δp >15 psid PERFORM the following:

- THROTTLE OPEN the selected MSIBV up to an additional ¼ turn to increase steam flow to the secondary.

_____/_____
Initials Date

- RETURN to Step 5.4.3 F.

_____/_____
Initials Date

NOTE: MSIBV(s) may be stroked by OPT-509A. After completion of OPT-509A, the MSIBVs will be locked closed. Main Steamline pressure and SG pressures should be equalized with a MSIBV prior to opening the MSIVs to ensure Steamlines are properly warmed.

5.4.3 G. IF OPT-509A testing is required for the MSIBV(s),
THEN
PERFORM one of the following:

1) IF only one MSIBV is required to be tested,
THEN
PERFORM Step 5.4.3.H (OPT-509A testing is completed in Step 5.4.3.J). ______/______ Initials Date

OR

2) IF multiple MSIBVs were required to be tested
AND
this is the last MSIBV test,
THEN
PERFORM Step 5.4.3.H (OPT-509A testing is completed in Step 5.4.3.J). ______/______ Initials Date

OR

3) IF multiple MSIBVs are required to be tested,
THEN
PERFORM the following:

a) STROKE the MSIBV that is currently open per OPT-509A. ______/______ Initials Date

b) RETURN to Step 5.4.3.D. ______/______ Initials Date

H. OPEN the following:

- ☐ 1-HV-2333A-AS1, MSIV 1-01 HYD PMP AS1
- ☐ 1-HV-2334A-AS1, MSIV 1-02 HYD PMP AS1
- ☐ 1-HV-2335A-AS1, MSIV 1-03 HYD PMP AS1
- ☐ 1-HV-2336A-AS1, MSIV 1-04 HYD PMP AS1

______/______ Initials Date

> CAUTION: During MODE 2, 3 or 4, one MSIV bypass valve may be opened provided the other three bypass valves are locked closed AND their associated MSIVs are closed.

5.4.3 I. WHEN MS HDR PRESS is equalized (Δp ≤ 15 psid) with MSL PRESS corresponding to the open MSIBV,
THEN
OPEN the MSIV on the Steam Line with the open MSIBV:

- MSIV 1-HS-________ ______/______ Initials Date

J. PERFORM the following:

1) IF a stroke test is required for the MSIBV currently open,
THEN
TEST the MSIBV per OPT-509A. ______/______ Initials Date

[C] 2) ENSURE ALL MSIBVs are closed AND locked:

- 1-HV-2333B, MSIV 1-01 BYP VLV ______/______ Initials Date
  ______/______ Verify Date
- 1-HV-2334B, MSIV 1-02 BYP VLV ______/______ Initials Date
  ______/______ Verify Date
- 1-HV-2335B, MSIV 1-03 BYP VLV ______/______ Initials Date
  ______/______ Verify Date
- 1-HV-2336B, MSIV 1-04 BYP VLV ______/______ Initials Date
  ______/______ Verify Date

5.4.3 K. OPEN the remaining MSIVs:

- ☐ • 1-HS-2333A, MSIV 1
- ☐ • 1-HS-2334A, MSIV 2
- ☐ • 1-HS-2335A, MSIV 3
- ☐ • 1-HS-2336A, MSIV 4

_______ / _______
Initials Date

L. ENSURE the full stroke test of the MSIVs has been performed within the required frequency per OPT-509A (TS SR 3.7.2.1) (RT# 505757, 505758, 505768, 505769).

_______ / _______
Initials Date

<u>CAUTION</u>:

- The preferred methods to maintain Reactor Power and temperature prior to Turbine Generator synchronization are use of Steam Dumps and SG Blowdown Flow. Steam Dump operation and Main Steam Line Drain flow affect LP Turbine casing ΔT, which should be monitored prior to synchronization.
- If LP Turbine casing ΔT approaches limits prior to synchronization, a reduction in Steam Dump operation may be required, and Main Steam Line drain flow should also be limited.
- The preferred method, to reduce Steam Dump Operation and Main Steam Line drain flow, is maintaining maximum SG Blowdown flow.
- SG Atmospherics should not be routinely used to minimize Steam Dump operation.

[C] 5.4.4 <u>IF</u> the SG ARVs are being utilized to maintain Main Steam pressure,
<u>THEN</u>
PLACE the Steam Dumps in service as follows:

A. <u>SLOWLY</u> RAISE 1-PK-507, STM DMP PRESS CTRL demand to maintain 1-PI-507, MS HDR PRESS at approximately 1092 psig.

_______ / _______
Initials Date

B. VERIFY the SG ARVs are CLOSED:

- ☐ • 1-ZL-2325, SG 1 ATMOS RLF VLV
- ☐ • 1-ZL-2326, SG 2 ATMOS RLF VLV
- ☐ • 1-ZL-2327, SG 3 ATMOS RLF VLV
- ☐ • 1-ZL-2328, SG 4 ATMOS RLF VLV

_______ / _______
Initials Date

5.4.4 C. SLOWLY ADJUST the SG ARV controllers setpoint to 1125 psig per TDM-501A:

- ☐ • 1-PK-2325, SG 1 ATMOS RLF VLV
- ☐ • 1-PK-2326, SG 2 ATMOS RLF VLV
- ☐ • 1-PK-2327, SG 3 ATMOS RLF VLV
- ☐ • 1-PK-2328, SG 4 ATMOS RLF VLV

IF using form OPT-308-2 for the startup, AND ICRR data indicates criticality will be achieved outside the ±500 PCM Evaluation Criteria but within the ±1000 PCM Shutdown Criteria,
THEN
CONTACT Core Performance Engineering AND continue the startup (Do not exceed 5% Reactor power until resolved).

_____/_____
Initials Date

D. ENSURE 1-PK-507, STM DMP PRESS CTRL controller is set to maintain 1092 psig per TDM-501A.

_____/_____
Initials Date

E. PLACE 1-PK-507, STM DMP PRESS CTRL in automatic.

_____/_____
Initials Date

5.4.5 NOTIFY Generation Controller of the Reactor startup and the estimated time for synchronization.

_____/_____
Initials Date

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5.4.6 PERFORM the following to start a Main Feed Pump and prepare for FW flow to SGs:

A) START 1A OR 1B Main Feed Pump per SOP-302A.

_____/_____
Initials Date

> CAUTION: In MODE 1 or 2 with one MFP supplying flow to the SGs, the second MFP must remain tripped or have the trip oil pressure switches isolated to ensure compliance with TS 3.3.2 (CR-2010-000638).

B) ISOLATE the trip oil pressure switches for the non-running FWP as follows:

1) ENSURE the selected FWP is tripped.

_____/_____
Initials Date

2) ISOLATE the selected FWP trip oil pressure switches:

FWP 1-A

☐ • 1TO-0331, FWPT 1-A TRIP OIL PRESS IND SW 2111A RT VLV - CLOSED
AND
☐ 1-PS-2111A, FEEDWATER PUMP TURBINE 1-A TRIP OIL PRESSURE INDICATION SWITCH 2111A - LESS THAN 100 PSIG

☐ • 1TO-0332, FWPT 1-A TRIP OIL PRESS IND SW 2111B RT VLV - CLOSED
AND
☐ 1-PS-2111B, FEEDWATER PUMP TURBINE 1-A TRIP OIL PRESSURE INDICATION SWITCH 2111B - LESS THAN 100 PSIG

_____/_____
Initials Date

FWP 1-B

☐ • 1TO-0333, FWPT 1-B TRIP OIL PRESS IND SW 2112A RT VLV - CLOSED
AND
☐ 1-PS-2112A, FEEDWATER PUMP TURBINE 1-B TRIP OIL PRESSURE INDICATING SWITCH 2112A - LESS THAN 100 PSIG

☐ • 1TO-0334, FWPT 1-B TRIP OIL PRESS IND SW 2112B RT VLV - CLOSED
AND
☐ 1-PS-2112B, FEEDWATER PUMP TURBINE 1-B TRIP OIL PRESSURE INDICATING SWITCH 2112B - LESS THAN 100 PSIG

_____/_____
Initials Date

5.4.7 The following steps describe the method used to adjust Main Feedwater Pump speed.

NOTE:
- The FWP DISCH HDR PRESS - MS HDR PRESS ΔP should be maintained, as necessary, to allow controlled feeding of the SGs. Higher Δ Ps (near 80 psig) at low power, may cause inadvertent feeding of the SGs due to leakage through the FCVs.
- Plant Computer point U5002A, FW - MS HEADER DP provides indication of differential pressure between the FW Pump discharge header and the Main Steam header. Plant Computer point U5003A, DELTA PROGRAM - ACTUAL DP provides indication of the difference between the programmed differential pressure and actual differential pressure.
- FWPT speed should be maintained as low as reasonable but greater than 1800 rpm. Minimize operation in the range of 2500 to 3100 rpm due to FWPT critical speed of approximately 2800 rpm.
- Experience has shown that on a sudden increase in oil system flow, (i.e., when FWP speed is raised quickly) the standby MOP may start. (EV-CR-1999-001167-1)

A. ADJUST running Feedwater Pump speed using the turbine manual speed controller to maintain 1-PI-0508, FWP DISCH HDR PRESS approximately 50 - 80 psig greater than 1-PI-0507, MS HDR PRESS (Plant Computer point U5002A, FW - MS HEADER DP).

- ☐ 1-SC-2111B, FWPT A MAN SPD CTRL
- ☐ 1-SC-2112B, FWPT B MAN SPD CTRL

B. VERIFY FWP suction flow and suction pressure remain within normal bands:

- ☐ 1-FI-2289, FWP 1A SUCT FLO
- ☐ 1-PI-2295, FWP 1A SUCT PRESS
- ☐ 1-FI-2290, FWP 1B SUCT FLO
- ☐ 1-PI-2297, FWP 1B SUCT PRESS

_______ / _______
Initials Date

NOTE: The Condensate Pump Recirculation Valve may be THROTTLED as necessary to obtain the desired Condensate flow while maintaining flow above 6000 gpm (Trip to Auto setpoint) so that the recirculation valve will not trip to the open position.

5.4.8 ADJUST 1-FK-2239, CNDS PMP RECIRC CTRL as necessary to obtain the desired Condensate flow.

_______ / _______
Initials Date

5.4.9 DELETED

[C] 5.4.10 ENSURE ALL SG FW FLO CTRL valve controllers are in MANUAL (0% demand) AND the valves are CLOSED.

_____/_____
Initials Date

5.4.11 ENSURE ALL SG FW BYP CTRL valve controllers are in MANUAL AND 0% demand.

_____/_____
Initials Date

5.4.12 ENSURE the Feedwater Bypass Control valve handswitches are in AUTO AND the valves are CLOSED:

- ☐ • 1-HS-2162, SG 1 FW BYP & CTRL VLV
- ☐ • 1-HS-2163, SG 2 FW BYP & CTRL VLV
- ☐ • 1-HS-2164, SG 3 FW BYP & CTRL VLV
- ☐ • 1-HS-2165, SG 4 FW BYP & CTRL VLV

_____/_____
Initials Date

5.4.13 RESET the Feedwater Isolation signal by depressing the following pushbuttons:

- ☐ • 1/1-FWIRA, FW ISOL RESET
- ☐ • 1/1-FWIRB, FW ISOL RESET

_____/_____
Initials Date

5.4.14 VERIFY 1-ALB-8A, 1.13, LO TAVE & RX TRIP FW ISOL ACT is OFF.

_____/_____
Initials Date

NOTE:
- When Feedwater Bypass Control valves are open, the SG will be fed by two sources, which will require the operator to manipulate Auxiliary Feedwater flow to prevent SG level oscillations.
- The following three steps should be performed simultaneously in order to maintain proper SG level.

5.4.15 THROTTLE OPEN the Feedwater Bypass Control valve controllers in MANUAL:

- ☐ • 1-LK-550, SG 1 FW BYP CTRL
- ☐ • 1-LK-560, SG 2 FW BYP CTRL
- ☐ • 1-LK-570, SG 3 FW BYP CTRL
- ☐ • 1-LK-580, SG 4 FW BYP CTRL

_____/_____
Initials Date

5.4.16 VERIFY flow to each SG through the Main Feed line:

- ☐ 1-FI-510A, SG 1 FW FLO
- ☐ 1-FI-511A, SG 1 FW FLO
- ☐ 1-FI-520A, SG 2 FW FLO
- ☐ 1-FI-521A, SG 2 FW FLO
- ☐ 1-FI-530A, SG 3 FW FLO
- ☐ 1-FI-531A, SG 3 FW FLO
- ☐ 1-FI-540A, SG 4 FW FLO
- ☐ 1-FI-541A, SG 4 FW FLO

_____ / _____
Initials Date

5.4.17 THROTTLE CLOSED the Auxiliary Feedwater Flow Control valve controllers:

- 1-FK-2453A, MD AFWP 1 SG 1 FLO CTRL
- 1-FK-2453B, MD AFWP 1 SG 2 FLO CTRL
- 1-FK-2454A, MD AFWP 2 SG 3 FLO CTRL
- 1-FK-2454B, MD AFWP 2 SG 4 FLO CTRL

_____ / _____
Initials Date

NOTE:	The SG level control system is selected to the preferred channels to preserve the 2/3 coincidence on high level Turbine trip in the event the alternate level control channel fails.

5.4.18 ENSURE the SG level channel select switches are in the following position:

- 1-LS-519C, SG 1 LVL CHAN SELECT - LQY-551
- 1-LS-529C, SG 2 LVL CHAN SELECT - LQY-552
- 1-LS-539C, SG 3 LVL CHAN SELECT - LQY-553
- 1-LS-549C, SG 4 LVL CHAN SELECT - LQY-554

_____ / _____
Initials Date

5.4.19 WHEN Main Feedwater flow is sufficient to maintain SG level,
THEN
TERMINATE Auxiliary Feedwater flow AND PLACE the system in standby per SOP-304A.

_____ / _____
Initials Date

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CAUTION: Do not perform the following step if FWP suction pressure is< 280 PSIG.

5.4.20 CONTACT Rad Waste Operator to DISABLE "FWP Suction Header Pressure Low Trip" Override per RWS-109A.

_____ / _____
Initials Date

5.4.21 IF desired,
THEN
PLACE the Feedwater Bypass Control Valve controllers in AUTO:

- 1-LK-550, SG 1 FW BYP CTRL
- 1-LK-560, SG 2 FW BYP CTRL
- 1-LK-570, SG 3 FW BYP CTRL
- 1-LK-580, SG 4 FW BYP CTRL

_____ / _____
Initials Date

NOTE: To ensure equal run-time for the Main Oil Pumps, MOP A should be placed in service during even number refueling outages and MOP B during odd number refueling outages.

5.4.22 IF a backup MOP started as FWP speed was raised,
THEN
STOP selected FWPT(s) MOP to be the standby pump
AND
ENSURE handswitch in AUTO:

- 1-HS-3297, FWPT A MOP A
- 1-HS-3298, FWPT A MOP B
- 1-HS-3300, FWPT B MOP A
- 1-HS-3301, FWPT B MOP B

_____ / _____
Initials Date

5.4.23 WHEN all steps of this IPO have been completed, OBTAIN the Shift Manager approval,
THEN
PROCEED to IPO-003A and file this procedure per ODA-104.

_____ / _____
Initials Date

REMARKS/COMMENTS____

____

IPO-002A satisfactorily completed:_____________________ / _____
SHIFT MANAGER Date

6.0 REFERENCES

6.1 Performance References

6.1.1 Technical Specifications/TRM/ODCM

- TS 3.1.1, Shutdown Margin (SDM)
- TS 3.1.3, Moderator Temperature Coefficient (MTC)
- TS 3.1.4, Rod Group Alignment Limits
- TS 3.1.5, Shutdown Bank Insertion Limits
- TS 3.1.6, Control Bank Insertion Limits
- TS 3.1.7, Rod Position Indication
- TS 3.1.8, Physics Test Exceptions - MODE 2
- TS 3.3.1, Reactor Trip System (RTS) Instrumentation
- TS 3.3.2, Engineered Safety Feature Actuation System (ESFAS) Instrumentation
- TS 3.4.2, RCS Minimum Temperature for Criticality
- TS 3.4.4, RCS Loops - MODE 1 and 2
- TS 3.4.5, RCS Loops - MODE 3
- TS 3.4.13, RCS Operational Leakage
- TS 3.4.14, RCS Pressure Isolation Valve (PIV) Leakage
- TS 3.7.2, Main Steam Isolation Valves (MSIVs)
- TRM 13.1.39, Rod Position Indication - Shutdown
- TRM 13.7.38, Main Feedwater Isolation Valve Pressure/Temperature Limit
- ODCM 4.11.2, Gaseous Effluents

6.1.2 CPNPP Procedures

- CHM-120, Primary Chemistry
- CHM-130, Secondary Chemistry
- INC-7375A, Analog Channel Operational Test and Channel Calibration Neutron Flux Power Range, Channel N41
- INC-7376A, Analog Channel Operational Test and Channel Calibration Neutron Flux Power Range, Channel N42
- INC-7377A, Analog Channel Operational Test and Channel Calibration Neutron Flux Power Range, Channel N43
- INC-7378A, Analog Channel Operational Test and Channel Calibration Neutron Flux Power Range, Channel N44
- INC-7379A, Analog Channel Operational Test and Channel Calibration Intermediate Range Channel N35
- INC-7380A, Analog Channel Operational Test and Channel Calibration Intermediate Range Channel N36
- INC-7381A, Analog Channel Operational Test and Channel Calibration Neutron Flux Source Range Channel N31
- INC-7382A, Analog Channel Operational Test and Channel Calibration Neutron Flux Source Range Channel N32
- INC-4383A, Channel Calibration Neutron Flux Source Range Channel N31 High Flux at Shutdown
- INC-4384A, Channel Calibration Neutron Flux Source Range Channel N32 High Flux at Shutdown
- IPO-001A, Plant Heatup From Cold Shutdown To Hot Standby
- IPO-003A, Power Operations

6.1.2 CPNPP Procedures (continued)

- NUC-101, Zero Power and Power Ascension Test Sequence
- NUC-111, Inverse Count Rate Ratio Monitoring
- NUC-116, Rod Withdrawal Limits
- NUC-206, Control Rod Operability
- NUC-301, Low Power Physics Testing
- ODA-102, Conduct of Operations
- ODA-104, Operations Department Document Control
- ODA-108, Post RPS/ESF Actuation Evaluation
- ODA-308, LCO Tracking Program
- ODA-401, Control of Annunciators, Instruments and Protective Relays
- OPT-102A, Operations Shiftly Routine Tests
- OPT-104A, Operations Weekly Routine Tests
- OPT-106A, Control Rods Exercise
- OPT-117, Digital Rod Position Indication
- OPT-301, Reactor Shutdown Margin Verification
- OPT-303, Reactor Coolant System Water Inventory
- OPT-308, Calculating Estimated Critical Condition
- OPT-410A, Pre-Startup Turbine Trip Checks
- OPT-440A, Manual SI And Reactor Trip TADOT
- OPT-441A, Reactor Trip P-4 TADOT
- OPT-443A, Reactor Trip Breaker And Stationary Gripper Coil Response Time
- OPT-445A, Mode 5 and 6 Train A SSPS Actuation Logic Test
- OPT-446A, Mode 5 and 6 Train B SSPS Actuation Logic Test
- OPT-447A, Mode 1, 3 and 4 Train A SSPS Actuation Logic Test
- OPT-448A, Mode 1, 3 and 4 Train B SSPS Actuation Logic Test
- OPT-509A, MSIV Testing
- OPT-611A, Pressure Boundary Leakage Test For RHR And SI Valves
- OPT-612A, RCS Pressure Boundary Leakage Test For SI Loop 1 & 2 Valves
- OPT-613A, RCS Pressure Boundary Leakage Test For SI Loop 3 & 4 Valves
- OPT-614A, RCS Pressure Boundary Leakage Test For CCP Injection to RCS C.L.
- OPT-615A, RCS Pressure Boundary Leakage Test For Train A C.L. Injection Valves
- OPT-616A, RCS Pressure Boundary Leakage Test For Train B C.L. Injection Valves
- OWI-104, Operations Department Logkeeping and Equipment Inspections
- OWI-107, Operations Department Turnover and Briefing Instructions
- OWI-409, Equipment Rotation
- RWS-109A, Condensate Polishing System
- SOP-103A, Chemical and Volume Control System
- SOP-104A, Reactor Make-up and Chemical Control System
- SOP-106A, Boron Thermal Regeneration System
- SOP-301A, Main Steam System
- SOP-302A, Feedwater System
- SOP-303A, Condensate System
- SOP-304A, Auxiliary Feedwater System
- SOP-307A, Extraction Steam System
- SOP-308A, Heater Drains System
- SOP-309A, Condenser Vacuum and Waterbox Priming System
- SOP-310A, Circulating Water System
- SOP-311, Auxiliary Steam System

6.1.2 CPNPP Procedures (continued)

- SOP-313A, Turbine Plant Cooling Water System
- SOP-401A, Turbine Control Fluid System
- SOP-402A, Turbine Gland Steam System
- SOP-404A, Turbine Lube Oil System
- SOP-407A, Generator Seal Oil System
- SOP-408A, Generator Primary Water System
- SOP-511, Nitrogen Gas System
- SOP-611A, Isolated Phase Bus Duct Cooling System
- SOP-702A, Rod Control System
- SOP-703, Excore Instrumentation System
- STA-421, Initiation of Condition Reports
- STA-603, Control of Station Radioactive Effluents
- STA-610, Secondary Water Chemistry Control Program
- STA-735, Nuclear Fuel Integrity Program
- TDM-102A, Reactor Control Rod Data
- TDM-103A, Reactor Coefficient and Defect Data
- TDM-301A, RCS Temperature & Pressure Limits
- TDM-310A, Circulating Water System Data
- TDM-501A, S/G - Feedwater Controller Data

6.2 Development References

- CP-0003-002, ACPSI Turbine Generator Instruction Manual
- CP-0003-003, ACPSI Turbine Generator Instruction Manual
- CP-0005-002, Steam Turbine Feed Pump Drive
- Westinghouse Reference Operating Procedure 0-1
- SOER 07-1,Reactivity Management, Commitment 3667655 and 3667657
- SOER 88-2(recommendation #6), Commitment 23344
- SOER 94-02, Boron Dilution Events in PWRs, Commitment 26876
- Commitment 4872850, Revise Mode Change Checklists

7.0 ATTACHMENTS

7.1 Attachment 1, Checklist Signoff Required Prior to Entry into MODE 2

7.2 Attachment 2, Inverse Count Rate Ratio Calculation

7.3 Attachment 3, DRPI ROD DEV Alarm Verification

7.4 Attachment 4, Balance of Plant Activities

7.5 Attachment 5, Shutdown To MODE 3 From 1 X 10^{-8} AMPS

7.6 Attachment 6, Actions for Insertion of Rods Past Zero (0) Steps

7.7 Attachment 7, MODE 3 to MODE 2 Bubble Chart

ATTACHMENT 7
PAGE 1 OF 5

MODE 3 TO MODE 2 BUBBLE CHART

Instructions:

- The bubble chart includes all steps in the IPO.
- It is divided into four sections.

  A. Section 5.1 is diagramed throughout with hexagons

  B. Section 5.2 is diagramed throughout with circles

  C. Section 5.3 is diagramed throughout with triangles

  D. Section 5.4 is diagramed throughout with squares

  E. Steps diagramed with inverted triangles indicate steps carried from a previous section or steps may that carry to the next section.

- All steps found in parallel can be performed at the same time or in any order.
- Solid lines designate preferred method.
- Dark center line designates main procedure flowpath.
- Partially colored blocks indicate secondary plant steps.
- A systematic step-by-step review and implementation of the procedure instructions (steps, notes and cautions) is required to implement this IPO. The chart on Attachment 7 gives guidance as to what sequence the IPO steps may be performed when going from MODE 3 to MODE 2.
- IF this chart is used,
  THEN
  the IPO must still be signed off in its entirety.

CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-002A
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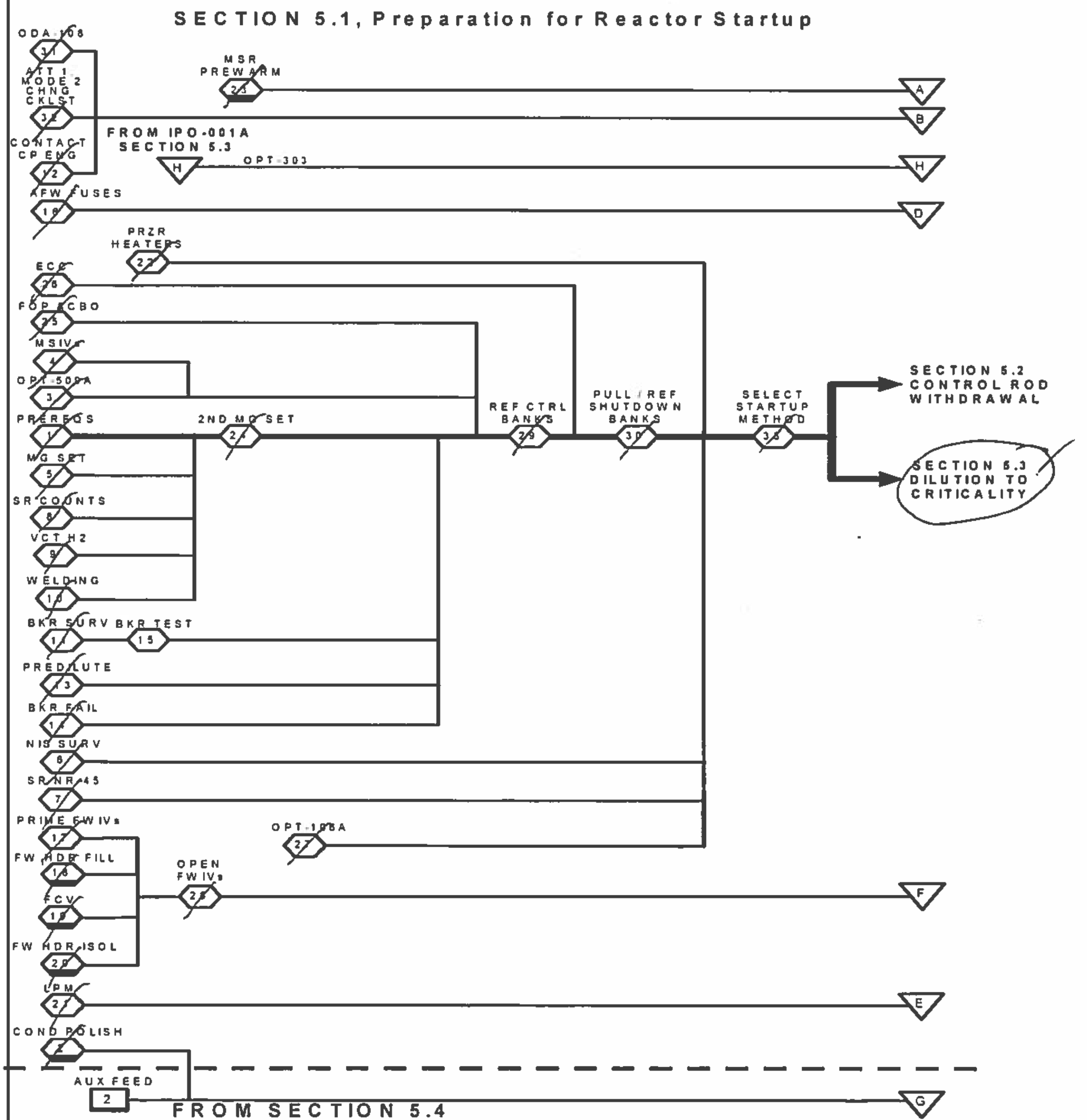
MODE 3 TO MODE 2 BUBBLE CHART



CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-002A
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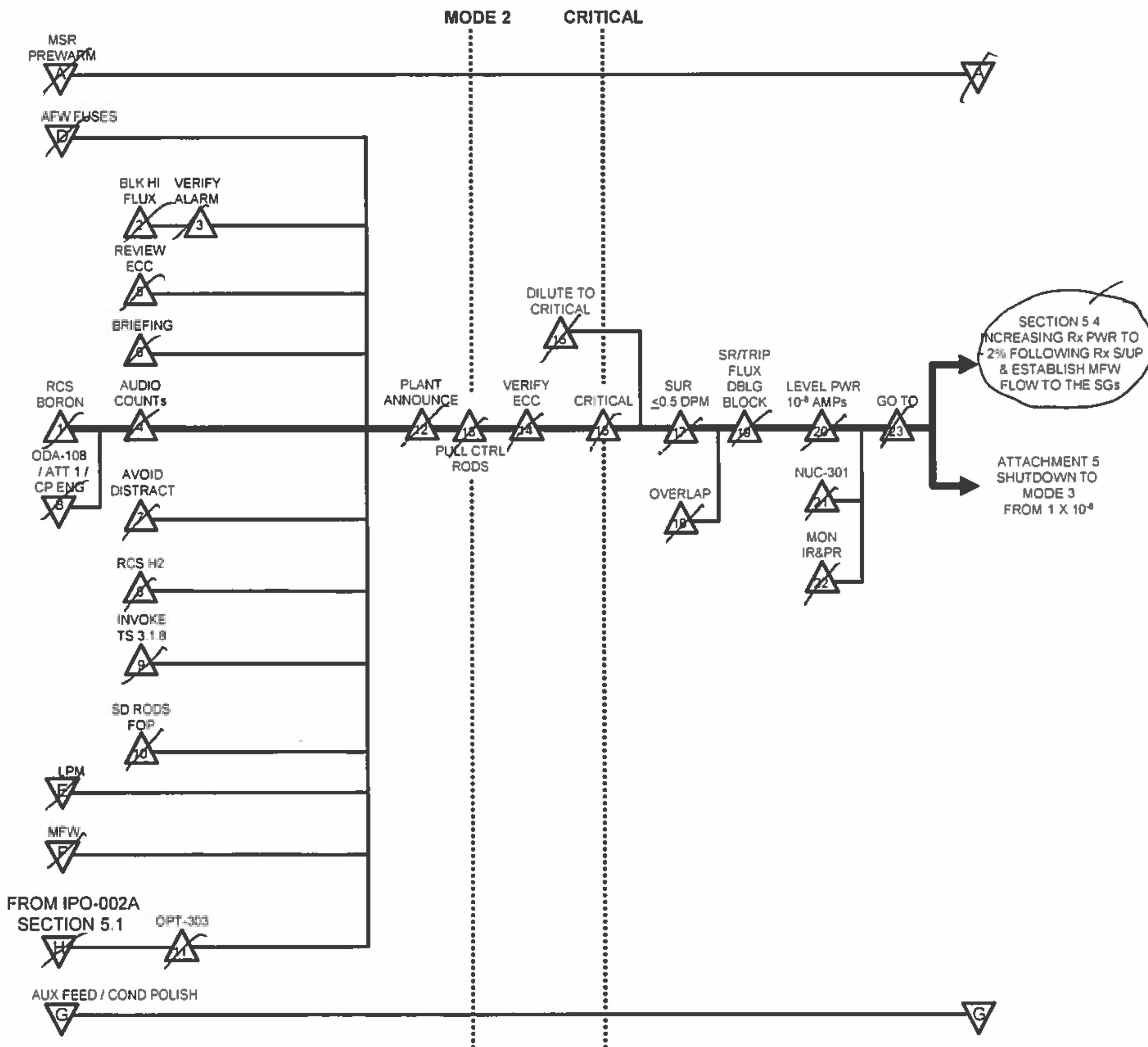
PAGE 4 OF 5

MODE 3 TO MODE 2 BUBBLE CHART

SECTION 5.3, Dilution to Criticality, Initial Startup Following Refueling



CPNPP INTEGRATED PLANT OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. IPO-002A
PLANT STARTUP FROM HOT STANDBY	REVISION NO. 21 / CONTINUOUS USE	PAGE 97 OF 98

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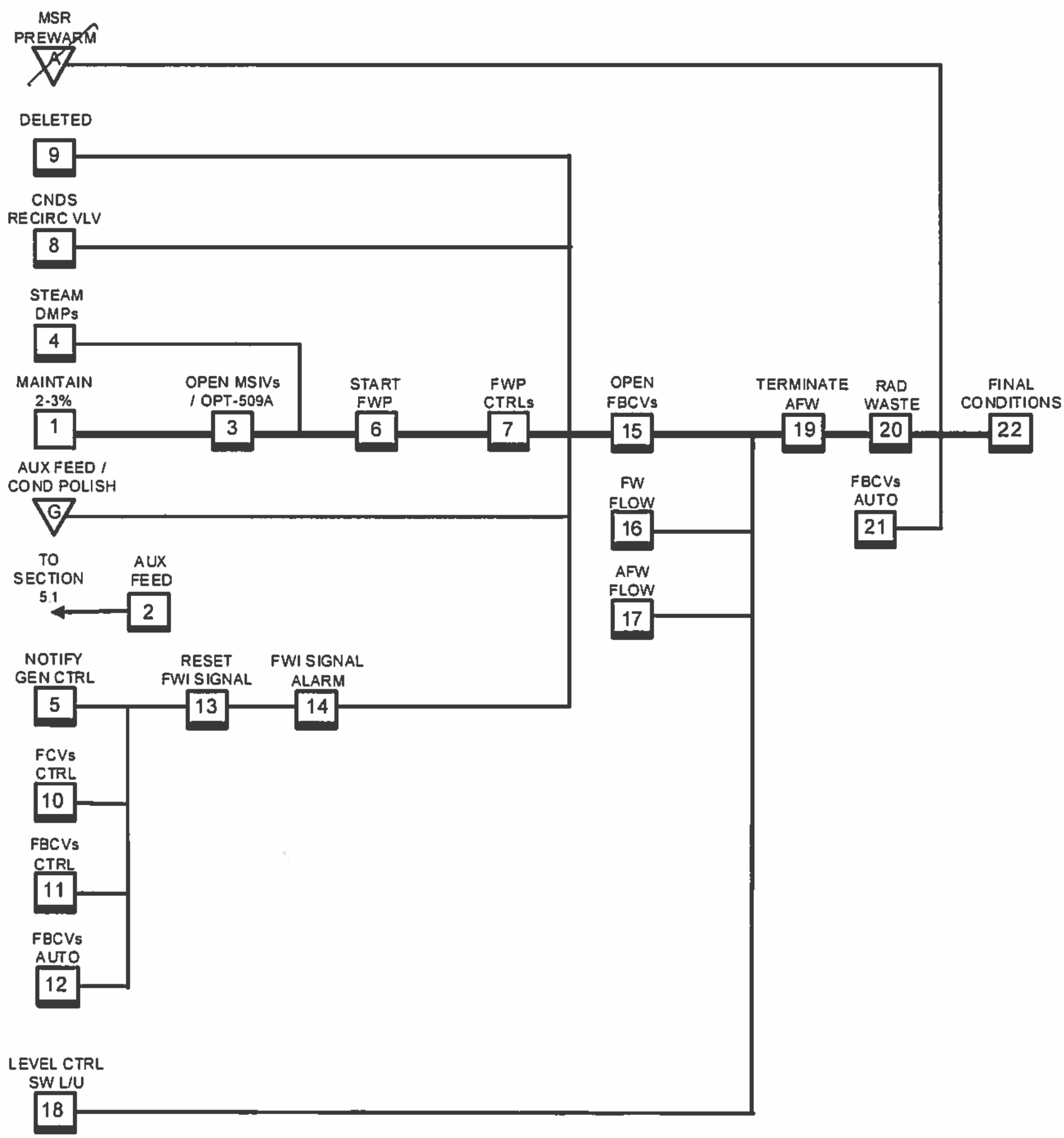
MODE 3 TO MODE 2 BUBBLE CHART

SECTION 5.4, Increasing Reactor Power to Approximately 2% Following Reactor Startup and Establishing Main Feedwater Flow to SGs



UNIT SUPERVISOR RELIEF CHECKLIST

UNIT: 1

OFF-GOING US: Unit Supervisor SHIFT: Night DATE: 2Day

ON-COMING US: ______ SHIFT: ______

PART I TO BE PREPARED BY THE OFF-GOING UNIT SUPERVISOR.

1.0 SHIFT ACTIVITIES:

1.1 Activities Completed This Shift:

Reactor dilution to criticality per IPO-002A. IPO-002A Section 5.3 is complete.

Low Power Physics Testing

1.2 Activities In-Progress:

Maintaining Reactor power 10^{-8} amps.

1.3 Planned Activities:

Continue IPO-002A at section 5.4 to raise power

Continue power escalation

2.0 PLANT AND EQUIPMENT STATUS:

2.1 Technical Specification Related Equipment Summary:

All equipment is operable

2.2 Non-Technical Specification Equipment Summary:

Secondary plant ready for power escalation. SG's being fed by MDAFW Pumps.

MSR Prewarming in progress

UNIT SUPERVISOR RELIEF CHECKLIST

3.0 General Information: None

4.0 END OF SHIFT REVIEW:

LOGS – RO/BOP x LOGS-NEO x CLOSED eLCOARs ARCHIVED x
OPTS COMPLETED x DAILY ACTIVITIES LIST x LCOARs REVIEWED x
COMP ACTIONS REVIEWED x

PART II TO BE COMPLETED BY THE ON-COMING UNIT SUPERVISOR.

1.0 CRITICAL PARAMETERS:

MODE: 2 REACTOR POWER: 1x10-8amps MWe: 0
RCS TAVE: 557 °F CONTROL ROD POSITION 99 ON BANK D
C_b: 1669 ppm RCS PRESS: 2235 psig

2.0 STATUS REVIEW:

	x	UNIT LOGS
[C]	x	* * LCOAR AND SYSTEMS IMPORTANT TO SAFETY STATUS [26082, 23486]
	x	UNIT DIFFERENCES (If last watch was on opposite unit)
	x	SHIFT ORDERS
	x	BOARD WALKDOWN
	x	* POD
[C]	x	CONDITIONAL SURVEILLANCE STATUS BOARD [23486]
	x	LOCATION OF SAFEGUARDS INFORMATION
	x	* RISK PROFILE FOR SHIFT

PROTECTED TRAIN [X] Train "A" [ ] Train "B"

* May be completed after turnover.
* * Each US's (U1 & U2) status review is to include the U1 & Common LCOAR & SIS Logs for Common equipment.

SHIFT RELIEF: ______________________ / ____________ / ____________
ON-COMING US SIGNATURE DATE TIME

Unit Supervisor
OFF-GOING US SIGNATURE

ON-COMING FSS REVIEW

SHIFT MANAGER REVIEW

Facility: CPNPP 1 & 2	Scenario No.: 4	Op Test No.: June 2017 NRC	
Examiners: ____ ____ ____	Operators: ____ ____ ____		

Initial Conditions: 92% power MOL – RCS boron is 777 ppm (by sample). Power has been reduced for Main Turbine testing; Control Bank D Rods are at 202 steps in Automatic. MDAFW Pump 1-02 is out of service for an oil change.

Turnover: Maintain 92% power conditions. Place RWST on Recirculation using Containment Spray pump 1-01.

Critical Tasks:

CT-1 - Trip all Reactor Coolant Pumps in accordance with FRH-0.1A, Response To Loss Of Secondary Heat Sink, prior to Initiating Bleed and Feed Cooling.

CT-2 - Initiate RCS Feed and Bleed in accordance with FRH-0.1A, Response To Loss Of Secondary Heat Sink, such that the RCS depressurizes sufficiently for Intermediate Head Injection to occur, prior to all Steam Generator Wide Range level lowering to 0%.

Event No.	Malf. No.	Event Type*	Event Description
1	-	N (BOP, SRO)	Recirculate the Refueling Water Storage Tank with Containment Spray Pump 1-01.
2	MS13C	I (RO, SRO)	SG 1-03 Steam Line Pressure Fails High (PT-2327) – ARV Opens
3	CS02A	TS (SRO)	Containment Spray Pump 1-01 Trip.
4	NI04E	I (RO, BOP, SRO) TS (SRO)	NI42 Power Range Channel fails high.
5	CH03	C (BOP, SRO)	Neutron Detector Well Fan 9 trips on motor overload
6	FW22	R (RO) C (BOP, SRO)	Low Pressure Feedwater Heater Bypass Valve (PV-2286) Fails Open.
7	FW20A	M (RO, BOP, SRO)	Condensate Pump 1-01 trips; requiring a manual reactor trip.
8	ED05H FW09A	M (RO, BOP, SRO)	Loss of 6.9KV Bus 1EA1 (86-1 relay) when Generator Output Breakers Open TDAFW Pump trips on overspeed, Loss of all AFW
9	RX16B	C (RO, SRO)	PORV 456 fails to open manually or automatically

* (N)ormal, (R)eactivity, (I)nstrument, (C)omponent, (M)ajor, (TS)Technical Specifications

Actual	Target Quantitative Attributes
9	Total malfunctions (5-8)
3	Malfunctions after EOP entry (1-2)
5	Abnormal events (2-4)
2	Major transients (1-2)
1	EOPs entered/requiring substantive actions (1-2)
1	EOP contingencies requiring substantive actions (0-2)
2	Critical tasks (2-3)

SCENARIO 4 SUMMARY

Event 1
As directed by the turnover the crew will recirculate the Refueling Water Storage Tank (RWST) using Containment Spray Pump 1-01 per SOP-204A, Containment Spray System, Section 5.1.3, Recirculation through the Recirculation Header.

Event 2
SG 1-03 Steam Line Pressure (PT-2327) fails high opening the ARV. Crew actions are per ABN-709, STM Line, STM HDR and Turbine 1st Stage Press, Feed HDR Press Instrument Malfunction. The crew will respond by checking STM Line pressures against set point and determining the ARV is open below set point. The RO will place the ARV in manual and close the valve.

Event 3
When conditions are stable, Containment Spray Pump 1-01 will trip. Actions are per ALM-0022A, 1-ALB-2B, Window 1.3 – ANY CSP OVRLD TRIP. The SRO will refer to Technical Specifications.

Event 4
Event 4 is a failure high of NI42 Power Range Channel. The crew will enter ABN-703, Power Range Instrumentation Malfunction. Since the failure is in the high direction, rods will be rapidly inserting. This will require the operator to place rod control to Manual, per Step 1.b of ABN-703. The SRO will refer to Technical Specifications.

Event 5
Event 4 will be a trip of the running Neutron Detector Well Fan #9. This will alarm 2.1 CNTMT FN MASTER TRIP. The ALM will direct the crew to determine which fan has tripped and start the other fan as required using SOP-801A, Containment Ventilation System. The crew will place the tripped fan handswitch in Pull Out or Stop as applicable.

Event 5
The Low Pressure Heater Bypass Valve fails open. Entry into ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 7.0, is required and Rod Control is returned to AUTO and a Manual Turbine Runback to 900 MWe is performed. During this event, Control Rod position may drop below the Rod Insertion Limit (RIL) and when informed, the SRO will refer to Technical Specifications

Event 6
Major Event, Condensate Pump 1-01 trips. Both Main Feedwater Pumps trip and the reactor will be manually tripped. The crew will enter EOP-0.0A, Reactor Trip or Safety Injection.

Event 7
The crew will experience a loss of Bus 1EA1. This will occur at the same time the Main Generator Breaker opens on the unit trip. With MDAFW Pump 1-02 tagged out, there are no motor driven AFW pumps available. There are no Main Feedwater Pumps or Condensate Pumps available. The only source of feedwater will be the Turbine Driven AFW Pump.

Events 8 & 9
The TDAFW pump will trip on overspeed, leaving no viable source of feedwater and when Heat Sink is lost the crew will transition to FRH-0.1A, Response to Loss of Secondary Heat Sink. The step for checking that both Centrifugal Charging Pumps are available will be answered with a "NO", requiring tripping of all Reactor Coolant Pumps and to initiate bleed and feed. One PORV will fail to open; this will require all reactor vessel and pressurizer head vents to be opened.

Termination Criteria
The scenario will be terminated when bleed and feed is initiated in accordance with FRH-0.1A; or at the discretion of the lead examiner.

Risk Significance:

- Failure of risk important system prior to trip: Loss of Containment Spray Pump 1-01
  Loss of Main Feedwater Pumps due to
  Loss of Condensate Pumps
- Risk significant core damage sequence: Loss of one Safeguards Bus (1EA1)
  TDAFW Pump trips on overspeed
- Risk significant operator actions: Restore Pressurizer Pressure Control
  Manually trip reactor on loss of all feedwater
  Initiate bleed and feed

Critical Task Determination

Critical Task	Safety Significance	Cueing	Measurable Performance Indicators	Performance Feedback
Trip all Reactor Coolant Pumps in accordance with FRH-0.1A, Response To Loss Of Secondary Heat Sink, prior to Initiating Bleed and Feed Cooling.	Without a source of water to provide a heat sink on the secondary side of the SGs, RCPs are tripped to extend the effectiveness if the remaining water inventory in the SGs.	Procedural direction at FRH-0.1A Step 2 RNO a. to immediately stop all RCPs.	The operator will manually stop RCPs using the handswitches on CB-05.	Control board light and flow indications, along with loss of flow annunciators that the RCPs have stopped.
Initiate RCS Bleed and Feed in accordance with FRH-0.1A, Response To Loss Of Secondary Heat Sink, such that the RCS depressurizes sufficiently for Intermediate-Head Injection to occur, prior to all Steam Generator Wide Range levels lowering to 0%.	Actuating SI ensures feed path of cool water to the RCS and isolates the containment to confine any RCS releases from the bleed flow. The bleed flow through a PORV/Vent valves will ensure that enough cool water will feed from the ECCS flow path to remove sufficient decay heat.	AFW flow will not be indicated on any AFW flow meter. Also no AFW pumps will be running. A RED path showing on CSFST for heat sink. The need for a heat sink as indicated by RCS temperature and pressure.	Actuated SI, ensured at least one CCP and SI pump is running with flow indicated providing a feed path for the RCS. PRZR PORV as well as PRZR and Vessel vent valves open providing a bleed path for the RCS.	Flow indicated on both a CCP and an SI pump. PRZR PORV open with block valve open. PRZR and Vessel vents open. RCS pressure lowering and CETs will indicate core cooling.

	SIMULATOR OPERATOR INSTRUCTIONS for SIMULATOR SETUP				
INITIALIZE to IC 49 and LOAD NRC Scenario 4.					
EVENT	**TYPE**	**MALF #**	**DESCRIPTION**	**DEMAND VALUE**	**INITIATING PARAMETER**
SETUP	IRF	FWR021	MDAFWP 1-02 Breaker Racked Out	f:0	K0
8	IMF	ED05H	Bus 1EA1 86-1 lockout.	f:1	(1)
	IMF	FW09A	TDAFW Pump trips on overspeed. {LORPRTBAL_1.Value=1} IMF FW09A	f:1	Rx Trip + 480
9	IMF	RX16B	PORV 456 fails to open manually or automatically	f:1	K0
1	-	-	Recirculate RWST with CSP 1-01	-	-
2	IMF	MS13C	SG ARV PT-2327 Fails High – ARV opens	f:1300	K2
3	IMF	CS02A	Containment Spray Pump 1-01 Trip	f:1	K3
4	IMF	NI04E	NI42 Power Range Channel fails high.	f:200	K4
5	IMF	CH03	Neutron Detector Well Fan 9 trips on motor overload	f:1	K5
6	IMF	FW22	Low Pressure Feedwater Heater Bypass Valve (PV-2286) fails open.	f:1	K6
7	IMF	FW20B	Condensate Pump 1-01 trips	f:1	K7
8	IMF	ED05H	Bus 1EA1 86-1 lockout.	f:1	(1)
	IMF	FW09A	TDAFW Pump trips on overspeed. {LORPRTBAL_1.Value=1} IMF FW09A	f:1	Rx Trip + 480 (2)
9	IMF	RX16B	PORV 456 fails to open manually or automatically	f:1	K0
(1) {LOEGW3_1.Value=1} IMF ED05H f:1 Inserts ED05H when Gen. Output Bkrs open					
(2) {LORPRTBAL_1.Value=1} IMF FW09A Trip TDAFWP 480 seconds after Rx Trip					

Simulator Operator:	**INITIALIZE to IC49 and LOAD NRC Scenario 4.** **ENSURE all Simulator Annunciator Alarms are ACTIVE.** **ENSURE RED Danger Tag on MDAFWP 1-02 and place in PULL-OUT.** **ENSURE GEM Box PLACED on 1-HS-2450A for MDAFWP 1-01.** **ENSUURE all Control board Tags are removed.** **ENSURE Operator Aid Tags reflect current boron conditions (777 ppm)** **ENSURE Rod Bank Update (RBU) is performed.** **ENSURE Turbine Load Rate set at 10 MWe/min.** **ENSURE 60/90 buttons DEPRESSED on ASD.** **ENSURE ASD speakers are ON at half volume.** **ENSURE Reactivity Briefing Sheet printout provided with Turnover.** **ENSURE procedures in progress are on SRO desk:** **- COPY of IPO-003A, Power Operations, Section 5.5, Operating at Constant Turbine Load.** **ENSURE Control Rods are in AUTO with Bank D at 202 steps.**
Control Room Annunciators in Alarm: **PCIP-1.1 – SR TRN A RX TRIP BLK** **PCIP-1.2 – IR TRN A RX TRIP BLK** **PCIP-1.4 – CNDSR AVAIL STM DMP ARMED C-9** **PCIP-1.6 – RX ≥ 10% PWR P-10** **PCIP-2.1 – SR TRN B RX TRIP BLK** **PCIP-2.2 – IR TRN B RX TRIP BLK** **PCIP-2.5 – SR RX TRIP BLK PERM P-6** **PCIP-3.2 – PR TRN A LO SETPT RX TRIP BLK** **PCIP-4.2 – PR TRN B LO SETPT RX TRIP BLK** **1-SSII2 – Train B MDAFW is Solid Red**	

Operating Test :	NRC	Scenario #	4	Event #	1	Page	7	of	35
Event Description:	Recirculate the Refueling Water Storage Tank with Containment Spray Pump 1-01								

Time	Position	Applicant's Actions or Behavior
Examiner Note:		**The Refueling Water Storage Tank is recirculated using a Containment Spray Pump per SOP-204A, Containment Spray System.**
	US	DIRECT performance of SOP-204A, Containment Spray System, Section 5.1.3, Recirculation Through the Recirculation Header.

NOTE: IF the containment spray system is being started for performance of OPT-205A, THEN the following valves will be positioned as directed by the performance of the operability test.

- 1CT-0150, U1 CS CHEM EDUCT TST HDR ISOL VLV
- 1CT-0137, CS PMP 1-01/1-03 CHEM EDUCT TST LN ISOL VLV
- 1CT-0183, CS PMPS 1-02/1-04 CHEM EDUCT TST LN ISOL VLV
- 1CT-0075, CS PMP 1-03 EDUCT SUCT ISOL VLV
- 1CT-0023, CS PMP 1-04 EDUCT SUCT ISOL VLV
- 1CT-0079, CS PMP 1-01 EDUCT SUCT ISOL VLV
- 1CT-0027, CS PMP 1-02 EDUCT SUCT VLV

Time	Position	Applicant's Actions or Behavior
	BOP	ENSURE the system is in standby per Section 5.1.1. [Step 5.1.3.A]
	BOP	VERIFY Train A Chemical Additive Tank Discharge Valve – CLOSED. [Step 5.1.3.B]
		• 1-HS-4754, CHEM ADD TK DISCH VLV, Train A
	BOP	INITIATE trend of Containment Spray Pump 1-01 parameters on Plant Computer. [Step 5.1.3.C]

Operating Test :	NRC	Scenario #	4	Event #	1	Page	8	of	35
Event Description:	Recirculate the Refueling Water Storage Tank with Containment Spray Pump 1-01								

Time	Position	Applicant's Actions or Behavior

DESCRIPTION	CSP 1-01	CSP 1-02	CSP 1-03	CSP 1-04
CSP MOT OUTBD BRG TEMP	T9313A	T9318A	T9323A	T9328A
CSP MOT INBD BRG TEMP	T9314A	T9319A	T9324A	T9329A
CSP INBD BRG TEMP	T9315A	T9320A	T9325A	T9330A
CSP OUTBD BRG TEMP	T9316A	T9321A	T9326A	T9331A
CSP STAT WNDG TEMP	T9340A	T9341A	T9342A	T9343A

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY CS Pump 1-01 Recirculation Valve – OPEN. [Step 5.1.3.D]
		• 1-HS-4772-1, CSP 1 RECIRC VLV
	BOP	START Containment Spray Pump 1-01. [Step 5.1.3.E]
		• PLACE 1-HS-4764, CSP 1 in START position.

CAUTION:
- WHEN CCW flow is NOT available to the Containment Spray System, THEN system temperature should be maintained ≤150°F.
- RWST maximum temperature limit is 120°F per TS 3.5.4.

NOTE: Step F is a CONTINUOUS ACTION.

Time	Position	Applicant's Actions or Behavior
	BOP	IF RWST OR Containment Spray System temperatures approach 120^{o}F, THEN, STOP recirculation prior to exceeding 120^{o}F in the RWST Containment Spray System. [Step 5.1.3.F]

When Containment Spray Pump flow and pressure are verified, or at Lead Examiner discretion, PROCEED to Event 2.

Operating Test : NRC	Scenario # 4	Event # 2	Page 9 of 35				
Event Description:	SG 1-03 Steam Line Pressure Fails High (PT-2327) – ARV Opens						

Time	Position	Applicant's Actions or Behavior
Simulator Operator: When directed, EXECUTE Event 2 (Key 2). - SG 1-03 Steam Line Pressure Fails High (PT-2327) – ARV Opens		
Indications Available: **1-PI-2327, MSL 3 PRESS failed high** **1-ZL-2327, SG 3 ATMOS RLF VLV red OPEN light LIT** **Plant Computer alarm Y6704D, SG 3 ATM RLF VLV OPEN**		
NOTE: • Control responses will only occur if failure is in channel selected for control. • A Steam Generator Automatic Relief Valve will fail open only if associated pressure channel (u-PT-2325, 2326, 2327, or 2328) fails high.		
	RO	REFER to Annunciator Alarm Procedures.
	RO	RECOGNIZE SG 1-03 Steam Pressure Transmitter 1-PT-2327 has failed high.
	US	DIRECT performance of ABN-709, Steam Line Pressure, Steam Header Pressure, Turbine 1st Stage Pressure and Feed Header Pressure Instrument Malfunction Section 2.0, Steam Line Pressure Instrument Malfunction
	RO	CHECK ONE Main Steamline Pressure Channel indicating - GREATER THAN 60 psig difference between remaining channels. [Step 2.3.1]
		• 1-PI-2327, MSL 3 PRESS failed High
	RO	VERIFY Steam Generator Atmospheric Relief Valves – CLOSED: [Step 2.3.2]
		• 1-ZL-2327, SG 3 ATMOS RLF VLV indicates OPEN AND • 1-PI-2327, MSL 3 PRESS failed High
		• IF pressure is less than 1125 psig, THEN manually CLOSE affected atmospheric relief valve. [Step 2.3.2 RNO a] • Manually SG 1-03 Atmospheric Relief Valve using 1-PK-2327, SG 3 ATMOS RLF VLV CTRL
		• NOTIFY Chemistry that a release has occurred and for Chemistry to determine if a release permit is required per STA-603. [Step 2.3.2 RNO b]

Operating Test :	NRC	Scenario #	4	Event #	2	Page	10	of	35
Event Description:	SG 1-03 Steam Line Pressure Fails High (PT-2327) – ARV Opens								

Time	Position	Applicant's Actions or Behavior
		GO TO Step 11. [Step 2.3.2 RNO c]
	US	REFER to Technical Specifications per Attachment 6. [Step 2.3.11]
		• DETERMINE no LCO entry required
	US	INITIATE a Condition Report per STA-421, as applicable. [Step 2.3.12]
When the plant is stable, or at Lead Evaluator's discretion, PROCEED to Event 3.		

Operating Test : NRC	Scenario # 4	Event # 3	Page 11 of 35
Event Description: Containment Spray Pump 1-01 trips			

Time	Position	Applicant's Actions or Behavior
		<u>Simulator Operator</u>: When directed, EXECUTE Event 3 (Key 3). **- CS02A, Containment Spray Pump 1-01 trip.**
		<u>Indications Available</u>: **2B-1.3 – ANY CSP OVRLOAD / TRIP** **Containment Spray Pump 1-01 amber MISMATCH and white TRIP lights lit**
	BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE 1-HS-4764, CSP 1, Containment Spray Pump 1-01 amber MISMATCH and white TRIP lights LIT.
	US	DIRECT performance of ALM-0022A, 1-ALB-2B, Window 1.3 – ANY CSP OVRLD TRIP.
		<u>CAUTION</u>: Do not place pump handswitch in STOP if pump has tripped (white TRIP light). This will reset 86M relay (white TRIP light) and may result in an automatic restart.
	BOP	DETERMINE Containment Spray Pump 1-01 affected pump. [Step 1]
		<u>Simulator Operator</u>: When asked about status of Containment Spray Pump, REPORT that the motor casing is hot.
	BOP	DISPATCH a NEO to affected pump to check for signs of damage (smoke, acrid odor, overheating). [Step 2]
		<u>Simulator Operator</u>: When asked about status of Containment Spray (CS) Pump breaker, REPORT that the 50/51 overcurrent relays on Phases B & C are tripped.

Operating Test :	NRC	Scenario #	4	Event #	3	Page	12	of	35
Event Description:	Containment Spray Pump 1-01 trips								

Time	Position	Applicant's Actions or Behavior
	BOP	DISPATCH an NEO to 1APCS1, CONTAINMENT SPRAY PUMP 1-01 MOTOR BREAKER to determine cause of alarm. (1EA1/8/BKR). [Step 3]
		• IDENTIFY affected relays (red buttons) [Step 3.A] • DETERMINE if an overload condition exists (sustained current > 50 amps) [Step 3.B] • NOTIFY Control Room of affected relays and overload condition. [Step 3.C]
	BOP	IF an overload condition is indicated AND 1-HS-4776/4777, CS HX 1/2 OUT VLV are closed, THEN STOP affected pump(s). [Step 4]
	US	REFER TO TS 3.6.6 [Step 5]
		• LCO 3.6.6.A, Containment Spray System.
		• CONDITION A - One containment spray train inoperable. • ACTION A.1 - Restore containment spray train to OPERABLE status within 72 hours. • CONDITION B - Required Action and associated Completion Time of Condition A not met. • ACTION B.1 - Be in MODE 3 within 6 hours, <u>AND</u> • ACTION B.2 - Be in MODE 5 within 84 hours.
<u>Examiner Note</u>:		**Both Train A Containment Spray Pumps may be taken to PULLOUT to avoid having the OPERABLE Train A CS Pump 1-03 experience a runout condition in the event a Containment HI-3 signal is received.**
	US	CORRECT the condition or INITIATE a work request per STA-606. [Step 6]
When Technical Specifications are addressed, or at Lead Examiner discretion, PROCEED to Event 4.		

Operating Test :	NRC	Scenario #	4	Event #	4	Page	13	of	35
Event Description:	NI42 Power Range Channel Fails High								

Time	Position	Applicant's Actions or Behavior
Simulator Operator: **When directed, EXECUTE Event 4 (Key 4).** **- NI42 Power Range Channel fails high.**		
Indications Available: **5C-2.5 – 1 OF 4 OT N-16 HI** **6D-1.3 – 1 OF 4 HI SETPT PR FLUX HI** **6D-2.3 – 1 OF 4 LO SETPT PR FLUX HI** **6D-3.3 – 1 OF 4 PR FLUX RATE HI** **6D-1.4 – RX > 50% PWR UP PR DET FLUX DEV HI** **6D-3.4 – PR CHAN DEV** **6D-4.10 – QUADRANT PWR TILT** **6D-2.14 – OP HI FLUX ROD STOP C-2**		
	RO	REFER to Annunciator Alarm Procedures.
	RO	RECOGNIZE Power Range Nuclear Instrument N-42 detector failure.
Examiner Note: **If a Power Range Channel fails HIGH while the Rod Control System is in AUTO, Control Rods will be rapidly inserted.**		
	US	DIRECT implementation of ABN-703, Power Range Instrumentation Malfunction, Section 2.0, Power Range Instrument Malfunction.
	RO	VERIFY rapid Control Rod insertion – NOT REQUIRED. [Step 2.3.1]
		• VERIFY Reactor and Turbine Power – MATCHED. [Step 2.3.1.a] AND • VERIFY T_{AVE} less than 3°F above $T_{REF.}$ [Step 2.3.1.a]
		• PLACE Rod Control in MANUAL. [Step 2.3.1.b]
	RO	VERIFY Reactor Power < 75% rated thermal power. [Step 2.3.2]
	US	• INITIATE actions to comply with Technical Specification SR 3.2.4.2. [Step 2.3.2 RNO]
Examiner Note: **Step 3.a – 3.f may be handed off to the BOP to be performed at the Power Range Nuclear Instrument Cabinets. The BOP should have a discussion with the RO and inform what alarms will be cleared as a result of actions at the NI Cabinets.**		

Operating Test :	NRC	Scenario #	4	Event #	4	Page	14	of	35
Event Description:	NI42 Power Range Channel Fails High								

Time	Position	Applicant's Actions or Behavior
		PERFORM at Channel N-42 Drawers: [Step 2.3.3]
	RO/BOP	• At Detector Current Comparator Drawer, SELECT Rod Stop Bypass Switch to N-42. [Step 2.3.3.a]
	RO/BOP	• At Comparator and Rate Drawer, SELECT Comparator Channel Defeat Switch to N-42. [Step 2.3.3.b]
	RO/BOP	• At Detector Current Comparator Drawer, SELECT Upper Section Switch to N-42. [Step 2.3.3.c]
	RO/BOP	• At Detector Current Comparator Drawer, SELECT Lower Section Switch to N-42. [Step 2.3.3.d]
	RO/BOP	• At Detector Current Comparator Drawer, SELECT Power Mismatch Bypass Switch to N-42. [Step 2.3.3.e]
	RO/BOP	• At the Power Range A Drawer, SELECT Rate Mode Switch momentarily to RESET for N-42. [Step 2.3.3.f]
	RO/BOP	• PLACE 1/1-JS-411E, N16 PWR CHAN DEFEAT Switch to LOOP 2. [Step 2.3.3.g]
	RO/BOP	• PLACE 1/1-TS-412T, T_{AVE} CHAN DEFEAT Switch to LOOP 2. [Step 2.3.3.g]
	RO/BOP	PLACE 1/1-TS-411E, 1-TR-411 Channel Select to an OPERABLE channel. [Step 2.3.4]

NOTE: Rod Control should remain in MANUAL until all channels are operable.This does not preclude placing rods in AUTO during rapidly changing transient conditions such as runbacks, etc. as long as rod control is returned to MANUAL when the plant is stabilized.

Examiner Note: The Crew will devise a Reactivity Plan and conduct a Reactivity brief to restore Control Rods to their Previous position and restore TAVE-TREF deviation.

Operating Test :	NRC	Scenario #	4	Event #	4	Page	15	of	35
Event Description:	NI42 Power Range Channel Fails High								

Time	Position	Applicant's Actions or Behavior
	RO	RESTORE T_{AVE} to within 1ºF of $T_{REF.}$ [Step 2.3.5]
NOTE: P-10 permissive is interlocked with Source Range instruments. During a unit shutdown if P-10 permissive is in incorrect state, SR detectors cannot be re-energized. This affects SR RX Trip and SR Flux DBLG protection.		
	US/RO	Verify WITHIN 1 Hour, of Instrument Malfunction, Interlocks in - REQUIRED STATE: [Step 2.3.6]
		• RX & TURB ≤ 10% PWR P-7 (PCIP – 3.5) – DARK. [Step 2.3.6.a]
		• RX ≤ 48% PWR 3-LOOP FLO PERM P-8 (PCIP – 4.5) – DARK. [Step 2.3.6.a]
		• RX ≤ 50% PWR TURB TRIP PERM P-9 (PCIP – 1.7) – DARK. [Step 2.3.6.a]
		• RX ≥ 10% PWR P-10 (PCIP – 1.6) – LIT. [Step 2.3.6.a]
	US/RO	• RECORD verification in Unit Log. [Step 2.3.6.b]
CAUTION: QUADRANT POWER TILT alarms (u-ALB-6D, 4.10) should be considered inoperable when any Power range channel is inoperable.		
	US/RO	CHECK Quadrant Power Tilt Ratio within limits: [Step 2.3.7]
		• CHECK Power Range Channels– ONE OR MORE INOPERABLE [Step 2.3.7.a]
		• CHECK Reactor Power – GREATER THAN 50%. [Step 2.3.7.b]
		• REFER to TS 3.2.4, Table 3.3.1-1, Items 2, 3 (ACTIONS D and E) and TR 13.2.33. [Step 2.3.7.c]
Examiner Note: **Step 2.3.8 is performed by I & C to locate problem and perform repairs; it is not included in the Scenario Guide.**		

Operating Test : NRC	Scenario # 4	Event # 4	Page 16 of 35
Event Description: NI42 Power Range Channel Fails High			

Time	Position	Applicant's Actions or Behavior
		NOTE: The following step allows I&C to troubleshoot failed channel while energized, to locate problem area. If troubleshooting can NOT be completed within 72 hours, Attachment 4 will cover ALL bistables regardless of partial or complete failure.
	US/RO	VERIFY interlocks match current power level: [Step 2.3.9]
		• RX & TURB <10% PWR P-7 (PCIP - 3.5)
		• RX <48% PWR 3-LOOP FLO PERM P-8 (PCIP - 4.5)
		• RX <50% PWR TURB TRIP PERM P-9 (PCIP - 1.7)
		• RX >10% PWR P-10 (PCIP - 1.6)
	US	EVALUATE Technical Specifications. [Step 2.3.10]
		• LCO 3.3.1.D, Reactor Trip System Instrumentation (Function 2.a, Power Range Neutron Flux High)
		• CONDITION D - One Power Range Neutron Flux-High channel inoperable. • ACTION D.1.1 - Perform SR 3.2.4.2 within 12 hours from discovery of THERMAL POWER> 75% RTP AND Once per 12 hours thereafter, AND • ACTION D.1.2 - Place channel in trip within 72 hours, OR • ACTION D.2 - Be in MODE 3 within 78 hours.
		• LCO 3.3.1.E, Reactor Trip System Instrumentation (Function 3.a, Power Range Neutron Flux Rate High Positive Rate)
		• CONDITION E - One channel inoperable. • ACTION E.1 - Place Channel in Trip in 72 hours. OR • ACTION E.2 - Be in MODE 3 in 78 hours.
		• LCO 3.3.1.S, Reactor Trip System Instrumentation (Function 18.e, Power Range Neutron Flux, P-10)
		• CONDITION S - One or more required channel(s) inoperable. • ACTION S.1 - Verify interlock is in the required state for existing unit conditions within 1 hour, OR • ACTION S.2 - Be in MODE 3 within 7 hours.

Operating Test :	NRC	Scenario #	4	Event #	4	Page	17	of	35
Event Description:	NI42 Power Range Channel Fails High								

Time	Position	Applicant's Actions or Behavior
		• LCO 3.3.1.T, Reactor Trip System Instrumentation. (Function 18.b, c, & d, Power Range Neutron Flux, P-7, P-8, & P-9)
		• CONDITION T - One or more required channel(s) inoperable. • ACTION T.1 - Verify interlock is in the required state for existing unit conditions within 1 hour. • ACTION T.2 - Be in MODE 2 within 7 hours.
	US	INITIATE a Condition Report per STA-421. [Step 2.3.11]

When the Technical Specification actions are addressed, or at Lead Evaluator's discretion, PROCEED to Event 5.

Operating Test : NRC	Scenario # 1	Event # 5	Page 18 of 35
Event Description: Neutron Detector Well Fan 9 trips on motor overload.			

Time	Position	Applicant's Actions or Behavior
Simulator Operator: When directed, EXECUTE Event 5 (Key 5) - CH03, Neutron Detector Well fan # 9 trips		
Indications Available: **3A-2.1 – CNTMT FN MASTER TRIP** **3A-1.4 – NEUT DET WELL FN CLR 9 DISCH TEMP HI** **3A-2.4 – NEUT DET WELL FN CLR 10 DISCH TEMP HI**		
	BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE Neutron Detector well fan #9 tripped
Simulator Operator: When contacted to investigate the fan trip wait 2 minutes and report back the breaker has tripped on motor overload.		
	US	DIRECT performance of ALM-0031A, 1-ALB-3A, Window 2.1 – CNTMT FN MASTER TRIP
Examiner Note: The following steps are from ALM-0031A, 1-ALB-3A, Window 2.1 – CNTMT FN MASTER TRIP		
NOTE: IF the trip is due to the overcurrent trip switch (OTS) , THEN the handswitch white light will be illuminated. A phase overcurrent trip can be identified at breaker compartment by red buttons on affected relays.		
NOTE: IF the trip is due to a Motor Overload, THEN the handswitch white light will be illuminated. A blown control power fuse OR breaker trip will cause a loss of all handswitch light indication.		
	BOP	DETERMINE affected fan from the associated handswitch light indication. [Step 1] • 1-HS-5435, NEUT DET WELL FN CLR FN 9 & DMPR
Examiner Note: The US may direct the operator to start an alternate fan prior to procedure direction.		
	BOP	START an alternate fan, as required per SOP-801A. [Step 2]

Operating Test : NRC	Scenario # 1	Event # 5	Page 19 of 35
Event Description: Neutron Detector Well Fan 9 trips on motor overload.			

Time	Position	Applicant's Actions or Behavior
Examiner Note:		**The crew may perform either Section 5.2.1, Neutron Detector Well Cooling System Startup OR Section 5.2.3, Alternating Neutron Detector Well Cooling Units to start the Alternate Fan.** **The following steps are from SOP-801A, Containment Ventilation System, Section 5.2.1, Neutron Detector Well Cooling System Startup**
	BOP	ENSURE the prerequisites in Section 2.2 are met. [Step A]
	BOP	START the selected cooling unit AND VERIFY the associated suction damper opens for the running fan AND the damper for the standby fan remains closed. [Step B] • 1-HS-5440, NEUT DET WELL FN CLR, FN 10 AND DMPR (1-HV-5440B)
	BOP	VERIFY the chill water return valve for the selected cooling unit automatically opens as indicated by the position lights on the valve's handswitch on CV-01. [Step C] • 1-HS-6709, NEUT DET WELL FN CLR 10 CH WTR RET VLV
	BOP	ENSURE 1-HS-6084, CH WTR SPLY ISOL VLV ORC is OPEN. [Step D]
Examiner Note:		**The crew may perform either Section 5.2.1, Neutron Detector Well Cooling System Startup OR Section 5.2.3, Alternating Neutron Detector Well Cooling Units to start the Alternate Fan.** **The following steps are from SOP-801A, Containment Ventilation System, Section 5.2.3, Alternating Neutron Detector Well Cooling Units**
	BOP	START the idle cooling unit AND VERIFY the associated suction damper opens. [Step A] • 1-HS-5440, NEUT DET WELL FN CLR, FN 10 AND DMPR (1-HV-5440B)

Operating Test :	NRC	Scenario #	1	Event #	5	Page	20	of	35
Event Description:	Neutron Detector Well Fan 9 trips on motor overload.								

Time	Position	Applicant's Actions or Behavior
	BOP	VERIFY the chill water return valve from the selected cooling unit automatically opens as indicated by the position lights on the valve handswitch on CV-01. [Step B] • 1-HS-6079, NEUT DET WELL FN CLR 10 CH WTR RET VLV
Examiner Note:		**The US should direct placing the tripped fan in PULL-OUT and Step C and D should NOT be performed as written.**
	BOP	SHUTDOWN the desired cooling unit by performing the following: [Step C]

		• STOP the cooling unit to be shut down AND VERIFY the associated suction damper closes. [Step C.1)]
		  • 1-HS-5435, NEUT DET WELL FN CLR, FN 9 AND DMPR (1-HV-5435B)
		• VERIFY the chilled water return valve closes. [Step C.2)]
		  • 1-HS-6078, NEUT DET WELL FN CLR 9 CH WTR RET VLV

		PLACE the shutdown cooling unit handswitch in AUTO. [Step D] • 1-HS-5435, NEUT DET WELL FN CLR, FN 9 AND DMPR (1-HV-5435B)
Examiner Note:		**The following steps continue with ALM-0031A, 1-ALB-3A, Window 2.1 – CNTMT FN MASTER TRIP**
	BOP	PLACE affected fan handswitch in Pull Out OR Stop, as available. [Step 3]
NOTE:		The Control Rod Drive Mechanism Fan AND Containment Air Cooling AND Recirc Fan Overcurrent Trip Switch can be reset locally at the breaker compartment OR by placing the handswitch in Trip OR Pull Out. The Reactor Coolant Pipe Penetration Fan, Preaccess Filtration Fan OR Neutron Detector Well Fan motor overload must be reset at the breaker.
Simulator Operator:		**When contacted to investigate the fan trip wait 2 minutes and report back the breaker has tripped on motor overload.**
	RO/BOP	DISPATCH an operator to affected fan breaker to determine cause of trip. [Step 4]

Operating Test :	NRC	Scenario #	1	Event #	5	Page	21	of	35
Event Description:	Neutron Detector Well Fan 9 trips on motor overload.								

Time	Position	Applicant's Actions or Behavior
	US	WHEN conditions permit, THEN PERFORM a Containment entry per STA-620 to check the fan for signs of damage (smoke, acrid odor, overheating). [Step 5]
	US	CORRECT the condition OR INITIATE a CR per STA-421, as applicable. [Step 6]
When the plant is stable or at Lead Examiner discretion, PROCEED to Event 5		

Operating Test :	NRC	Scenario #	1	Event #	6	Page	22	of	35
Event Description:	Low Pressure Feedwater Heater Bypass Valve fails open								

Time	Position	Applicant's Actions or Behavior
Simulator Operator: When directed, EXECUTE Event 6 (Key 6). - FW22, Low Pressure Feedwater Heater Bypass Valve fails open.		
Indications Available: 8B-3.8 – CNDS LP HTR BYP VLV OPEN PV-2286 Reactor Power rising and Main Feedwater temperature lowering		
	BOP	RESPOND to Annunciator Alarm Procedures.
	RO/BOP	OBSERVE rising Reactor Power and lowering Main Feedwater temperatures.
	US	DIRECT performance of ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 7.0, LP Heater Bypass Valve Opening at Power.
Examiner Note: The following steps are from ABN-302, Feedwater, Condensate, Heater Drain System Malfunction, Section 7.0, LP Heater Bypass Valve Opening at Power.		
Examiner Note: Diamond steps (◊) are Initial Operator Actions.		
CAUTION: • LP FW HTR BYP VLV opening at power will cause reactor power to increase. • Using Load Target to reduce load without rods in AUTO can result in excessive TAVE-TREF mismatch before C-7 activates. This mismatch may cause an SI when steam dumps trip open. NOTE: Diamond step 1 denotes Initial Operator Actions.		
Examiner Note: Control Rods will be in MANUAL from the previous NI-42 failure and will be placed in AUTO by the RO.		
	◊ US ◊	ENSURE Turbine Power – LESS THAN OR EQUAL TO 900 MWe. [Step 7.3.1]
	◊ RO ◊	• PLACE 1/1-RBSS, CONTROL ROD BANK SELECT Switch in AUTO.
	◊ BOP ◊	• MANUALLY RUNBACK Turbine Power to 900 MWe.

Time	Position	Applicant's Actions or Behavior
		• DEPRESS "900 MWe" Manual Runback button.
		• CLICK on "0/1" button.
		• CLICK on "EXECUTE" then VERIFY Runback in progress.

Simulator Operator: If contacted to inspect 1-PV-2286 for cause of failure, REPORT that Instrument Air piping to 1-PV-2286 has been severed and the valve has FAILED OPEN.

Simulator Operator: After 3 minutes, REPORT no indication of piping or hanger damage.

Time	Position	Applicant's Actions or Behavior
	US	Locally INSPECT Heater Drain System for signs of water hammer induced damage. [Step 7.3.2]
	BOP	ENSURE Feedwater Pump suction pressure > 250 PSIG. [Step 7.3.3]
		• 1-PI-2295, FWP A SUCT PRESS
		• 1-PI-2297, FWP B SUCT PRESS
	US/BOP	If required, RESET Turbine Runback per ABN-401. [Step 7.3.4]

Examiner Note: The following steps are from ABN-401, Main Turbine Malfunction, Section 8.0, Turbine Reloading after Runback.

Time	Position	Applicant's Actions or Behavior
		• VERIFY alarm 6D-1.9, ANY TURB RUNBACK EFFECTIVE – DARK. [Step 8.3.1]
		• In the Load Control Section, ENSURE Load Rate Setpoint Controller is SET to support reload or current plant conditions. [Step 8.3.2]
		• In the Load Control Section, ENSURE Load Target Setpoint Controller is set for actual MWe. [Step 8.3.3]
		• If Manual Runback was used, TURN OFF the appropriate Subloop Controller on the TG Control Display in the MANUAL RUNBACKS Section. [Step 8.3.4]
		• VERIFY Runback is RESET. [Step 8.3.5]
		• VERIFY Runback – GREATER THAN 15% WITHIN ONE HOUR and CONTACT Chemistry. [Step 8.3.6]

Time	Position	Applicant's Actions or Behavior
		• CONTROL Turbine Load as required per IPO-003A. [Step 8.3.7]

Examiner Note: **Combination of events prior to / during this scenario may result in exceeding the Rod Insertion Limits (RIL). The RO should inform the SRO when ALB-6D, Window 2.7 – ANY CONTROL ROD BANK AT LO-LO LIMIT is LIT. Technical Specifications must be referenced.**

Time	Position	Applicant's Actions or Behavior
	US	EVALUATE Technical Specifications.
		• LCO 3.1.6.A, Control Bank Insertion Limits.
		• CONDITION A - Control bank insertion limits not met. • ACTION A.1.1 - Verify SDM to be within the limits provided in the COLR within one (1) hour, <u>OR</u> • ACTION A.1.2 - Initiate Boration to restore SDM to within limit within one (1) hour, <u>AND</u> • ACTION A.2 - Restore control bank(s) to within limits within 2 hours.
	BOP	When Steam Dumps have closed - RESET C-7. [Step 7.3.5]
		• Momentarily PLACE 43/1-SD, STM DMP MODE SELECT in RESET.
		• VERIFY PCIP, Window 3.4 – TURB LOAD REJ STM DMP ARMED C-7 is DARK.

<u>NOTE</u>: Isolating the LP FW HTR BYP VLV will cause RCS temperature to initially decrease and steam flow to increase as more extraction steam is drawn from the turbine. Subsequently, this will cause feedwater temperatures increase which will result in an increase in RCS temperature and a decrease in reactor power.

Time	Position	Applicant's Actions or Behavior
	BOP	Locally SLOWLY CLOSE one manual isolation valve for 1-PV-2286, while adjusting Turbine Load to maintain Reactor Power stable. [Step 7.3.6]
		• 1CO-0148, U1 CNDS LP HTR BYP VLV 2286 UPSTRM ISOL VLV.
		• 1CO-0149, U1 CNDS LP HTR BYP VLV 2286 DNSTRM ISOL VLV.

Examiner Note: **The Shift Manager must be contacted and a Crew Brief conducted prior to isolating PV-2286. This evolution takes significant time and is performed locally, therefore, it is desirable to proceed with the next scenario event.**

Operating Test :	NRC	Scenario #	1	Event #	6	Page	25	of 35
Event Description:	Low Pressure Feedwater Heater Bypass Valve fails open							

Time	Position	Applicant's Actions or Behavior

When Technical Specifications have been referenced, or at Lead Examiner discretion, PROCEED to Event 6.

Operating Test :	NRC	Scenario #	1	Event #	7, 8, 9	Page	26	of	35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically								

Time	Position	Applicant's Actions or Behavior
Simulator Operator:		**When directed, EXECUTE Event 7 (key 7)** **- FW20A, Condensate Pump 1-01 Trip** **- ED05H, 1EA1 86-1 Lockout [when generator output breakers open]** **- FW09A, TDAFW Pump Overspeed Trip When EOS-0.1A is entered** **- RX16B, PORV-456 fails to open in auto or manual**
Indications Available: **8B-4.10 – CNDS PMP 1/2 OVERLOAD/TRIP** **1-PI-2295, FWP A SUCT PRESS Lowering** **1-PI-2297, FWP B SUCT PRESS Lowering** **7B-1.12 – FWPT A TRIP** **8A-1.3 – FWPT B TRIP**		
	RO/BOP	RESPOND to Annunciator Alarm Procedures.
	BOP	RECOGNIZE trip of Condensate Pump 1-01.
Examiner Note:		**Upon trip of a Condensate Pump BOTH MFPs will trip at current power level. When the MFPs trip the US will direct a manual Reactor Trip inserted and will enter EOP-0.0A, Reactor Trip or Safety Injection.**
	BOP	RECOGNIZE trip of both Main Feed pumps
	US	DIRECTS performance of EOP-0.0A, Reactor Trip or Safety Injection.
	RO	VERIFY Reactor Trip: [Step 1]
		• PLACE 1/1-RTC, RX TRIP BKR in TRIP position and VERIFY Reactor Trip. [Step 1]
		• VERIFY the following: [Step 1.a]
		• DETERMINE Reactor Trip Breakers – OPEN AND
		• DETERMINE Neutron flux – DECREASING. [Step 1.a]
		• DETERMINE all Control Rod Position Rod Bottom Lights – ON. [Step 1.b]
	BOP	VERIFY Turbine Trip: [Step 2]
		• DETERMINE all HP Turbine Stop Valves – CLOSED.

Operating Test : NRC	Scenario # 1	Event # 7, 8, 9	Page 27 of 35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically		

Time	Position	Applicant's Actions or Behavior
Examiner Note:		**The US may contact the SM and request additional personnel to perform the appropriate ABN for loss of power.**
Examiner Note:		**When Train A Safeguards power is lost to 1EA1, DG 1-01 will be running unloaded with NO SSW flow. DG 1-01 must be secured within 15 minutes of start to prevent damage.**
Simulator Operator:		**When/If contacted as the SM acknowledge request for additional personnel to perform actions of ABN-601/602.**
	BOP	VERIFY Power to AC Safeguards Buses: [Step 3]
		• AC safeguards busses – AT LEAST ONE ENERGIZED [Step 3.a]
		• DETERMINE 1EA2 Bus ENERGIZED at 6900 Volts
		• AC safeguards busses – BOTH ENERGIZED [Step 3.b]
		• RESTORE power to de-energized AC safeguards bus per ABN-601, RESPONSE TO A 138/345 KV SYSTEM MALFUNCTION or ABN-602, RESPONSE TO A 6900/480 VOLT SYSTEM MALFUNCTION when time permits. [Step 3.b RNO b]
	US/RO	CHECK SI status: [Step 4]
		• CHECK if SI is actuated: [Step 4.a]
		• SI actuation as indicated on the First Out Annunciator 1-ALB-6C • SI actuated blue status light – ON
		• CHECK if SI is required: [Step 4.a RNO a]
		• Steam Line Pressure less than 610 psig • Pressurizer Pressure less than 1820 psig • Containment Pressure greater than 3.0 psig
		• IF SI is NOT required, THEN go to EOS-0.1A, Reactor Trip Response, Step 1. [Step 4.a RNO a]

Operating Test :	NRC	Scenario #	1	Event #	7, 8, 9	Page	28	of	35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically								

Time	Position	Applicant's Actions or Behavior
Examiner Note:		**When the Reactor is tripped a loss of Safeguards Buss 1EA1 will occur due to an 86-1 Lockout. This will result in a loss of the only running Charging Pump, CCP 1-01. The RO should recognize the loss of Charging when he addresses RCP Seals during performance of EOP-0.0A foldout page actions and start CCP 1-02.**
Simulator Operator:		**When contacted concerning Bus 1EA1 report that the bus has an 86-1 Lockout Relay indication.**
Examiner Note:		**The TDAWP will trip on overspeed 8 minutes after it starts. With no AFW flow a Red Path will exist on Heat Sink when level in all Steam Generators drops below 43% NR and a transition to FRH-0.1A should occur.** **EOS-0.1A, Reactor Trip Response steps begin here.**
	US	DIRECT performance of EOS-0.1A, Reactor Trip Response.
CAUTION:		If SI actuation occurs during this procedure, EOP-0.0A, REACTOR TRIP OR SAFETY INJECTION shall be performed.
	RO	CHECK RCS Temperature - [Step *1]
		• CHECK RCPs – ANY RUNNING [Step 1.a]
		• RCS average temperature stable at or trending to 557ºF. [Step 1.b]
NOTE:		When establishing feedwater to SGs, at least two SGs should be used.
	RO/BOP	CHECK FW Status: [Step *2]
		• VERIFY Reactor Trip Breakers – OPEN. [Step 2.a]
		• CHECK RCS average temperatures < 564ºF. [Step 2.b]

Operating Test :	NRC	Scenario #	1	Event #	7, 8, 9	Page	29	of	35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically								

Time	Position	Applicant's Actions or Behavior
		• VERIFY Feedwater Isolation - ISOLATION Complete. [Step 2.c]
		• DETERMINE total AFW flow to SGs > 460 GPM. [Step 2.d]
Examiner Note:		**When the Reactor is tripped a loss of Safeguards Buss 1EA1 will occur due to an 86-1 Lockout. This will result in a loss of the only running Charging Pump, CCP 1-01. If the RO did not recognize the loss of CCP 1-01, EOS-0.1A will direct the crew to re-establish Charging flow in Step 3.b**
	RO	CHECK PRZR Level Control: [Step *3]
		• VERIFY PRZR Level > 17%. [Step 3.a]
		• VERIFY Charging - IN SERVICE. [Step 3.b]
		• PERFORM the following to place charging in service: [Step 3.b RNO b]
		• Ensure a charging pump running. IF CCW to RCP Thermal Barrier flow not available, THEN isolate RCP seal injection prior to charging pump start. [Step 3.b RNO b.1)]
		• Place charging flow control valve in manual and 35% demand. [Step 3.b RNO b.2)]
		• Ensure CCP miniflow valves, 1/1-8110 and 1/1-8111 open. [Step 3.b RNO b.3)]
		• Ensure CCP alternate miniflow isolation valves, 1/1-8511A and 1/1-8511B closed. [Step 3.b RNO b.4)]
		• Ensure charging line isolation valves, 1/1-8105 and 1/1-8106 open. [Step 3.b RNO b.5)]
		• Adjust charging flow control valve to establish charging flow. [Step 3.b RNO b.6)]
		• Adjust RCP seal flow to RCPs to maintain between 6 gpm and 13 gpm, if not isolated. [Step 3.b RNO b.7)]
		• VERIFY Letdown - IN SERVICE. [Step 3.c]
		• DETERMINE PRZR Level TRENDING to 25%. [Step 3.d]
	RO	CHECK PRZR Pressure Control: [Step *4]
		• DETERMINE PRZR Pressure > 1820 PSIG. [Step 4.a]
		• DETERMINE PRZR Pressure - TRENDING TO 2235 PSIG. [Step 4.b]

Operating Test :	NRC	Scenario #	1	Event #	7, 8, 9	Page	30	of	35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically								

Time	Position	Applicant's Actions or Behavior
	BOP	CHECK Steam Generator Levels: *[Step 5]
		• DETERMINE Narrow range level < 43%.
Examiner Note:		**When the TDAFWP trips all AFW flow is lost. The crew will enter FRH-0.1A when all SG levels are less than 43% as a RED Path will exist on Heat Sink. SG Levels may not have exceeded 43% prior to trip of the TDAFWP which will necessitate an immediate entry to FRH-0.1A.**
	US	Determines a Red Path will exist on Heat Sink, enters FRH-0.1A, Response to Loss of Secondary Heat Sink.
Examiner Note:		**FRH-0.1A steps begin here.**
	US	DIRECTS performance of FRH-0.1A, Response to Loss of Secondary Heat Sink.
CAUTION:		If total feed flow is less than 460 gpm due to operator action as directed by the ERGs, this procedure need not be performed.
CAUTION:		Feed flow should not be re-established to any faulted SG if a non-faulted SG is available.
	US/BOP	CHECK If Secondary Heat Sink Is Required: [Step 1]
		• DETERMINE RCS pressure – > ANY NON-FAULTED SG PRESSURE. [Step 1.a]
		• DETERMINE RCS temperature > 350ºF. [Step 1.b]

Operating Test :	NRC	Scenario #	1	Event #	7, 8, 9	Page	31	of	35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically								

Time	Position	Applicant's Actions or Behavior
	US/RO	DETERMINE Only CCP 1-02 – AVAILABLE. [Step *2]
		• Starts CCP 1-02 if not previously started.
CRITICAL TASK STATEMENT		**Trip all Reactor Coolant Pumps in accordance with FRH-0.1A, Response To Loss Of Secondary Heat Sink, prior to Initiating Bleed and Feed Cooling.**
		• Immediately PERFORM the following steps: [Step 2 RNO]
CT-1		• Stop All RCPs [Step 2 RNO a]
		• VERIFY power to PRZR PORV block valves - AVAILABLE [Step 2 RNO b]
		• DETERMINES power available to PORV block valve 1/1-8000B ONLY as 1EA1 is de-energized and unable to locally restore power.
		• Go to Step 13 [Step 2 RNO c]
CAUTION: Steps 13 through 22 must be performed quickly in order to establish RCS heat removal by RCS bleed and feed.		
	RO/BOP	Manually ACTUATE Safety Injection. [Step 13]

Operating Test :	NRC	Scenario #	1	Event #	7, 8, 9	Page	32	of	35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically								

Time	Position	Applicant's Actions or Behavior
	RO/BOP	VERIFY RCS Feed Path: [Step 14]
		• CHECK CCP SI flow indicator – CHECK FOR FLOW [Step 14.a] • CCP 1-02 is running with flow
		• CHECK SI pumps – BOTH RUNNING [Step 14.b]
		• PERFORM the following: [Step 14.b RNO b]
		• Manually start pumps and align valves as necessary - Unable to start SIP 1-01 as no power is available. [Step 14. B RNO b.1)]
		• IF either of the following RCS feed paths exist, THEN go to Step 15: [Step 14.b RNO b.2)] • CCPs – BOTH INJECTING -OR- • AT LEAST ONE CCP AND ONE SI PUMP RUNNING
Examiner Note:	**The following six steps are performed per FRH-0.1A, Attachment 1.D. This attachment may be handed off to an operator.**	
	BOP	[1.D] PLACE DG 1-02 EMER STOP/START handswitches In START. [Step 15]
	BOP	[1.D] RESET Safety Injection. [Step 16]
	BOP	[1.D] RESET Safety Injection Sequencers. [Step 17]
	BOP	[1.D] RESET Containment Isolation Phase A and B. [Step 18]
	BOP	[1.D] RESET Containment Spray Signal. [Step 19]

Operating Test :	NRC	Scenario #	1	Event #	7, 8, 9	Page	33	of	35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically								

Time	Position	Applicant's Actions or Behavior
	BOP/RO	[1.D] ESTABLISH instrument Air and Nitrogen To Containment. [Step 20]
		• ESTABLISH Instrument Air: [Step 20.a]
		• Verify Air Compressors – RUNNING. [Step 20.a.1)] -AND- • ESTABLISH Instrument Air to Containment by opening 1-HS-3487, CNTMT INSTR AIR ISOL VLV
		• ESTABLISH Nitrogen: [Step 20.b]
		• Verify 1-HC-943, ACCUM 1 4 Vent Valve CLOSED. [Step 20.b.1)]
		• OPEN SI/PORV ACCUM N2 ISOL VLV 1/1-8880. [Step 20.b.2)]
CRITICAL TASK STATEMENT		**Initiate RCS Feed and Bleed in accordance with FRH-0.1A, Response To Loss Of Secondary Heat Sink, such that the RCS depressurizes sufficiently for Intermediate Head Injection to occur, prior to all Steam Generator Wide Range level lowering to 0%.**
<u>Examiner Note</u>:		**With power available to only the Train B PORV Block Valve the operator should open the Train A PORV first and verify a pressure drop occurs as there is no indication of Train A PORV Block Valve position.** **The Train B PORV will fail to open when demanded by the operator thus requiring Rx Head and Pressurizer Vent Valves being opened.**
	RO	ESTABLISH RCS Bleed Path: [Step 21]
		• DETERMINE power to Train B PRZR PORV block valve – AVAILABLE. [Step 21.a]
		• VERIFY PRZR PORV Block Valves – BOTH OPEN. [Step 21.b]
CT-2		• OPEN 1-PCV-455A, PRZR PORV. [Step 21.c] • Train A PORV should be open first to verify system response due to no indication of Train A PORV Block Valve position
		• OPEN 1-PCV-456, PRZR PORV. [Step 21.c] • The Train B PORV will fail to open when demanded by the operator.

Operating Test :	NRC	Scenario #	1	Event #	7, 8, 9	Page	34	of	35
Event Description:	Condensate Pump 1-01 trips; requiring a manual reactor trip, Loss of 6.9 KV Bus 1EA1 (86-1 relay), TDAFW Pump trips on overspeed, PORV-456 fails to open manually or automatically								

Time	Position	Applicant's Actions or Behavior
		VERIFY Adequate RCS Bleed Path: [Step 22]
		• PRZR PORVs – BOTH OPEN • PRZR PORV block valves – BOTH OPEN
CT-2		• OPEN vents on Reactor Vessel Head and on the PRZR to containment. [Step 22 RNO]
When an adequate Reactor Coolant System bleed and feed path is aligned, TERMINATE the scenario.		

```
;CPNPP 2017 NRC Scenario 4
;Initial Conditions
;IC49 92% power

;MDAFW 2 Rackout
IRF FWR021 f:0

;TDAFWP trip if running
{LORPRTBAL_1.Value=1} IMF FW09A f:1 d:480

;1EA1 86-1 on gen brkr open
{LOEGW3_1.Value=1} IMF ED05H f:1

;PORV 456 fails to OPEN Auto or Manual
IMF RX16B f:0

;PT-2327 Fails High
IMF MS13C f:1300 k:2

;CS Pump 1-01 trip
IMF CS02A f:1 k:3

;N42 fails high
IMF NI04E f:200 k:4

;NDWC fan 9 trip
IMF CH03 f:1 k:5

;PV2286 opens
IMF FW22 f:100 k:6

;Cond pmp 1 trip
IMF FW20A f:1 k:7
```

GUARDED EQUIPMENT MANAGEMENT (GEM) SIGN POSTING LOG

REASON FOR POSTING MDAFW Pump 1-02

Component to be Posted	Nomenclature	Posting Installed	Posting Checked	Posting Removed
		Initial	Initial	Initial
1-HS- 2450A	MDAFW Pump 1-01	OPR	BOF	

Authorized By: Unit Superviser Date: Today Posting Removal Authorized By:__________ Date:__________

Open Narrative Log Entry Entered ☒ Open Narrative Log Entry Closed ☐

Comments:__________

REFERENCE USE

STI-600.01-1
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Rev. 0

COMANCHE PEAK NUCLEAR POWER PLANT

UNIT 1

SYSTEM OPERATING PROCEDURES MANUAL

FOR EMPLOYEE USE:
DATE VERIFIED/INITIALS m / 2day LATEST PCN/EFFECTIVE DATE PCN 5 / 9/29/15 1200

LEVEL OF USE:
CONTINUOUS USE

QUALITY RELATED

CONTAINMENT SPRAY SYSTEM

PROCEDURE NO. SOP-204A

REVISION NO. 15

EFFECTIVE DATE: 09/22/10 1200

PREPARED BY (Print): Greg Blythe Ext: 6769

TECHNICAL REVIEW BY (Print): Lisabeth Donley Ext: 6524

APPROVED BY: Alan Hall for Steven Sewell Date: 09/14/10
DIRECTOR, OPERATIONS

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CONTAINMENT SPRAY SYSTEM	REVISION NO. 15	PAGE 3 OF 50
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1.0 APPLICABILITY

This procedure provides instructions for operating the Containment Spray System.

2.0 PREREQUISITES

2.1 Placing the System in Standby

> NOTE: CCW flow to the Containment Spray Pumps and Heat Exchanger is not required provided system temperature is maintained ≤150°F and the affected train is declared inoperable per TS 3.6.6.
>
> NA

N/A

- ☐ CCW is available and aligned to the pump seal coolers.
- ☐ CCW is available to the heat exchangers.
- ☐ SSW is available and aligned to the pump bearing coolers.
- ☐ Nitrogen is available to the Chemical Additive Tank.
- ☐ The Chemical Additive Tank is available for chemical addition.
- ☐ Both spray trains have been filled and vented and the respective Containment Spray Risers are above the low level alarm.
- ☐ The RWST is filled and aligned to the SI header.
- The following valve lineups are complete:
  - ☐ SOP-204A-CT-V01, Train A Valve Lineup
  - ☐ SOP-204A-CT-V02, RWST Valve Lineup
  - ☐ SOP-204A-CT-V03, Chem Add Tank Valve Lineup
  - ☐ SOP-204A-CT-V04, Train B Valve Lineup
- The following control switch lineups are complete:
  - ☐ SOP-204A-CT-C01, Train A Control Switch Lineup
  - ☐ SOP-204A-CT-C02, Train B Control Switch Lineup
- The following electrical lineups are complete:
  - ☐ SOP-204A-CT-E01, Train A Electrical Lineup
  - ☐ SOP-204A-CT-E02, Train B Electrical Lineup

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2.2 Filling and Venting

2.2.1 Filling Train A

- The following valve lineups are complete:
  - ☐ SOP-204A-CT-V01, Train A Valve Lineup
  - ☐ SOP-204A-CT-V02, RWST Valve Lineup
  - ☐ SOP-204A-CT-V03, Chem Add Tank Valve Lineup
- ☐ The RWST is ≥ 25% and ALIGNED to the SI header.
- ☐ Demin Water is available in Containment for Spray Riser fill.
- ☐ The control switch lineup per SOP-204A-CT-C03, Train A Fill and Vent Control Switch Lineup is complete.

> NOTE: CCW flow to the Containment Spray Pumps and Heat Exchanger is not required provided system temperature is maintained ≤ 150°F and the affected train is declared inoperable per TS 3.6.6.
> N/A

- ☐ CCW is available and aligned to the pump seal coolers.
- ☐ SSW is available and aligned to the pump bearing coolers.

2.2.2 Filling Train B

- The following valve lineups are complete:
  - ☑ SOP-204A-CT-V02, RWST Valve Lineup
  - ☐ SOP-204A-CT-V03, Chem Add Tank Valve Lineup
  - ☑ SOP-204A-CT-V04, Train B Valve Lineup
- ☑ The RWST is ≥ 25% and aligned to the SI header.
- ☐ Demin Water is available in Containment for Spray Riser fill.
- ☑ The control switch lineup per SOP-204A-CT-C04, Train B Fill and Vent Control Switch Lineup is complete.

> NOTE: CCW flow to the Containment Spray Pumps and Heat Exchanger is not required provided system temperature is maintained ≤ 150°F and the affected train is declared inoperable per TS 3.6.6.
>
> NW

- ☑ CCW is available AND aligned to the pump seal coolers.
- ☐ SSW is available AND aligned to the pump bearing coolers.

2.2.3 Filling the Chemical Additive Tank

- ☐ Contact Chemistry in preparation for NaOH addition to tank.
- ☐ Demin Water is available at the Chem Add Tank.
- ☑ Nitrogen is available to the tank to supply cover gas.

3.0 PRECAUTIONS

- Thirty (30) percent by weight NaOH is highly basic and will cause caustic burns.

4.0 LIMITATIONS/NOTES

4.1 Limitations

- When at ambient temperature, two (2) consecutive starts are allowed with the motor coasting to rest between starts. Running time between additional starts should be 15 minutes. Time required at standstill between additional starts should be 45 minutes.
- When at rated temperature, one (1) additional start is allowed with the motor coasting to rest before the start. Running time between additional starts should be 15 minutes. Time required at standstill between additional starts should be 45 minutes.
- Two independent Containment Spray Systems shall be operable with each spray system capable of taking suction from the RWST and manually transferring suction to the containment sump any time the unit is in MODES 1, 2, 3 and 4 per TS 3.6.6.
- The Spray Additive System shall be operable with a spray additive tank level of between 91% and 94% of 28% to 30% NaOH solution by weight and four spray additive eductors each capable of adding NaOH solution from the chemical additive tank to a Containment Spray System pump flow in MODES 1, 2, 3 and 4 per TS 3.6.7 and TR 13.6.7.
- The Containment Spray System containment isolation valves shall be operable in MODES 1, 2, 3 and 4 per TS 3.6.3.
- The RWST shall be operable in MODES 1, 2, 3 and 4 per TS 3.5.4.
- RWST maximum temperature limit is 120°F per TS 3.5.4.
- Degraded Containment Spray Pump performance may be caused by gas instrusion into the Containment Spray System. Gas intrusion into the Containment Spray System may cause fluctuations in <u>OR</u> a reduction in Containment Spray Pump discharge pressure <u>OR</u> flow, <u>OR</u> increased pump vibration (Reference STA-698, "Gas Instrusion Program").

4.2 Notes

- The opening stroke time of the Containment Spray Heat Exchanger Discharge Valves (1-HV-4776 and 4777) is based on preventing an overcurrent trip of the Containment Spray Pump(s). The stroke time assumes a START of both pumps and an initial fill of the riser and associated piping in containment occurs. The following limitations apply:
    - IF a Containment Spray Pump is taken out-of-service, THEN the other pump in the same train should also be placed in pull out.
    - IF a Containment Spray Pump is taken out of standby due to the limitations above AND the pump is needed to support emergency operation, THEN the pump may be operated as required.
- The Containment Spray system is designed to operate with system temperature up to 300°F. When the system temperature exceeds 150°F, however, CCW flow must be aligned to the pump seal coolers to maintain integrity of the mechanical seals. In all cases, CCW flow must be available to both the Containment Spray Heat Exchanger and the mechanical seal cooler to declare the system operable per TS 3.6.6.
- Maintaining less than 25 inches vacuum for less than 12 hours, along with the sequence of instructions followed during the Containment Spray vacuum fill, ensures the Containment Spray System instrumentation which is vulnerable to damage from a vacuum is not exposed to conditions that may cause instrument damage or instrument drift.(EVAL-2000-003051-03 and -04)
- The Containment Spray Heat Exchanger CCW supply isolation valves, 1CC-0107 AND 1CC-0158, are butterfly valves which have holes drilled in the valve discs such that the valves operate functionally like an orifice. With the valves in their normal "LOCKED CLOSED" position, they allow the nominal CCW flow required for Containment Spray Heat Exchanger cooling.
- ENSURE oil level is always maintained in all CT Spray Pump oil bubblers prior to AND after all pump runs as well as after any Maintenance activities (i.e., oil samples or oil changes). Ref. CR-2010-005117

5.1.3 Recirculation Through the Recirculation Header

This section describes the steps required to align and start a Containment Spray Pump(s) AND recirculate to the RWST via the recirculation header.

NOTE: IF the containment spray system is being started for performance of OPT-205A, THEN the following valves will be positioned as directed by the performance of the operability test.

- 1CT-0150, U1 CS CHEM EDUCT TST HDR ISOL VLV
- 1CT-0137, CS PMP 1-01/1-03 CHEM EDUCT TST LN ISOL VLV
- 1CT-0183, CS PMPS 1-02/1-04 CHEM EDUCT TST LN ISOL VLV
- 1CT-0075, CS PMP 1-03 EDUCT SUCT ISOL VLV
- 1CT-0023, CS PMP 1-04 EDUCT SUCT ISOL VLV
- 1CT-0079, CS PMP 1-01 EDUCT SUCT ISOL VLV
- 1CT-0027, CS PMP 1-02 EDUCT SUCT VLV

☐ A. ENSURE the system is in standby per Section 5.1.1.

B. VERIFY the selected Train Chemical Additive Tank discharge valve is CLOSED.

☐ • 1-HS-4754, CHEM ADD TK DISCH VLV, Train A

☐ • 1-HS-4755, CHEM ADD TK DISCH VLV, Train B

CPNPP SYSTEM OPERATING PROCEDURES MANUAL	UNIT 1	PROCEDURE NO. SOP-204A
CONTAINMENT SPRAY SYSTEM	REVISION NO. 15	PAGE 16 OF 50
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5.1.3

☐ C. INITIATE a trend of the selected pump's parameters on the Plant Computer.

DESCRIPTION	CSP 1-01	CSP 1-02	CSP 1-03	CSP 1-04
CSP MOT OUTBD BRG TEMP	T9313A	T9318A	T9323A	T9328A
CSP MOT INBD BRG TEMP	T9314A	T9319A	T9324A	T9329A
CSP INBD BRG TEMP	T9315A	T9320A	T9325A	T9330A
CSP OUTBD BRG TEMP	T9316A	T9321A	T9326A	T9331A
CSP STAT WNDG TEMP	T9340A	T9341A	T9342A	T9343A

D. VERIFY the CS Pump recirculation valve is OPEN.

- ☐ 1-HS-4772-1, CSP 1 RECIRC VLV
- ☐ 1-HS-4772-2, CSP 3 RECIRC VLV
- ☐ 1-HS-4773-1, CSP 2 RECIRC VLV
- ☐ 1-HS-4773-2, CSP 4 RECIRC VLV

E. START the selected spray pump(s).

Train A

- ☐ 1-HS-4764, CSP 1
- ☐ 1-HS-4765, CSP 3

Train B

- ☐ 1-HS-4766, CSP 2
- ☐ 1-HS-4767, CSP 4

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5.1.3

CAUTION:	• WHEN CCW flow is NOT available to the Containment Spray System, THEN system temperature should be maintained ≤ 150°F. • RWST maximum temperature limit is 120°F per TS 3.5.4.

NOTE:	Step F is a CONTINUOUS ACTION.

☐ F. IF RWST OR Containment Spray System temperatures approach 120°F,
THEN
STOP recirculation prior to exceeding 120°F in the RWST OR Containment Spray System.

[IV] G. WHEN recirculation is complete,
THEN
STOP the running pump(s) AND ENSURE the handswitch(es) is in AUTO.

Train A

- ☐ 1-HS-4764, CSP 1
- ☐ 1-HS-4765, CSP 3

Train B

- ☐ 1-HS-4766, CSP 2
- ☐ 1-HS-4767, CSP 4

COMMENTS ______________________________

6.0 REFERENCES

6.1 Performance References

6.1.1 Technical Specifications

- 3.5.4, Refueling Water Storage Tank (RWST)
- 3.6.3, Containment Isolation Valves
- 3.6.6, Containment Spray System
- 3.6.7, Spray Additive System

6.1.2 Technical Requirements

- 13.6.7, Spray Additive System

6.1.3 INC-2100A, Instrument Valve Lineup

6.1.4 OPT-205A, Containment Spray System

6.1.5 SOP-501A, Station Service Water System

6.1.6 SOP-502A, Component Cooling Water System

6.2 Development References

6.2.1 Applicable Drawings

- M1-0232
- M1-0232 Sheet A

6.2.2 DBD-ME-0232, Containment Spray System

6.2.3 Westinghouse Containment Spray Motors Instruction Book, CP-0411-002

6.2.4 Bingham Containment Spray Pumps Instruction Book HS-002, CP-0012-001

6.2.5 FSAR Sections

- 6.2.2
- 6.5.2

6.2.6 OWI-103, "Locked Component Listing and Deviation Control"

6.2.7 Technical Evaluation 92-2591, Operating Containment Spray/Residual Heat Removal Pumps Without CCW

6.2.8 WPT-13884, TCX RHR Pump Operation Without Component Cooling Water

6.2.9 EVAL-2000-003051-03 and -04

6.3 <u>Commitments</u>

6.3.1 04249 Using the demineralized water transfer pumps, makeup to the spray headers inside the containment is obtained from the DWST by manual operation. A level switch is provided to monitor the level in the spray head riser.

Reactivity Briefing Sheet for Stable Operation

MOL PROJECTIONS - SIMULATOR USE ONLY

Valid for approximately 7 days.

Calculations based on core design values, and assume:

Burnup =	**12000.0**	MWD/MTU
	270.8	EFPD
Power =	**100**	RTP
Boron =	**775**	ppm
B10 Conc =	**0.183400**	w/o
Control Bank D =	**215**	steps

Burnup in the MOL range

NOTE: Re-create the Briefing Sheet if current values significantly differ from assumed inputs.

Reactivity affects of Control Bank D

HFP Diff Worth @ 215.0 steps = **-1.6** pcm / step

HFP Integral Rod Worth for CBD Step Positions:

Steps	pcm	Steps	pcm	Steps	pcm	Steps	pcm
225	0.0	218	-5.7	211	-17.7	200	-48.5
224	0.0	217	-7.0	210	-20.0	195	-65.6
223	-1.4	216	-8.4	209	-22.3	190	-83.6
222	-2.0	215	-10.0	208	-24.9	185	-102.0
221	-2.7	214	-11.7	207	-27.5	180	-120.4
220	-3.6	213	-13.6	206	-30.3	175	-138.7
219	-4.6	212	-15.6	205	-33.1	170	-156.7

Reactivity affects of Boron (Assuming BAT concentration of 7447.0 ppm)

HFP Diff Boron Worth @ 775 ppm = **-7.8** pcm / ppm

1-FK-110 Pot Setting for Blended Flow @ 775 ppm = **2.34** (90 gpm Total Flow)

1-FK-110 Pot Setting for Blended Flow @ 775 ppm = **3.30** (127 gpm Total Flow)

Reactivity affects of Power

Power Coefficient of Reactivity = **-16.0** pcm / % RTP

Dilution to equal 1% Power Increase = **180.5** gallons RMUW

Boration to equal 1% Power Decrease = **20.1** gallons boric acid

Reactivity affects of RCS Temperature

Temperature Coefficient of Reactivity (ITC) = **-21.5** pcm / ☜F

Boration to equal 1☜F Temperature Decrease = **27.1** gallons boric acid

Dilution to equal 1☜F Temperature Increase = **243.0** gallons RMUW

Load Reduction equal to 1☜F T_{ave} Increase = **16.0** MWe

Load Reduction Calculation Worksheet

Note: Do not perform these calculations following a Runback. For a Runback, borate per the Reactivity Briefing Sheets as soon as possible.

This computer generated form may be substituted for Attachment 1 of NUC-117 Rev 8

Contact Core Performance (817-432-0134) if possible to discuss the plan.

Unit ______ **Date / Time:** ____________________

A.1 Boration Volume _______________ **gallons**

Indicate source (listed in order of preference)

___ BEACON by Core Performance (obtain if time permits)
___ Reactivity Briefing Sheets from the Boration Matrix
___ CHORE output (under 'Tools' ->'Power Change Rx Calc IPO-003 ATT 3')
___ IPO-003A Attachment 3 Manual Calculation

A.2 Current Turbine Load Setpoint . . . . _______________ **MWe**

A.3 Final Turbine Load Setpoint . . . . _______________ **MWe**

(200 MWE if plant shutdown planned)

A.4 Total Turbine Ramp Time . . . . _______________ **minutes**

(Do not include calculation prep and Pre-Job Brief times)

Calculations:

B.1 Load Change . . . . _______________ **MWe**

= A.2 - A.3

B.2 Load Rate . . . . _______________ **MWe/min**

= B.1 / A.4

B.3 Total Boration Time . . . . _______________ **minutes**

Ideally, start time should be 5 minutes BEFORE load change is initiated.

If time does not allow, start time should be same as the load change start time.

Ideally, end time should be 15 minutes BEFORE load change is complete.

B.4 Boration Rate . . . . _______________ **gpm**

= A.1 / B.3

B.5 1-FK-110 Pot Setting . . . . _______________ **turns**

= B.4 / 4 (N/A for Batch Boration)

Reactivity Briefing Sheet for Runback to 900 MWe

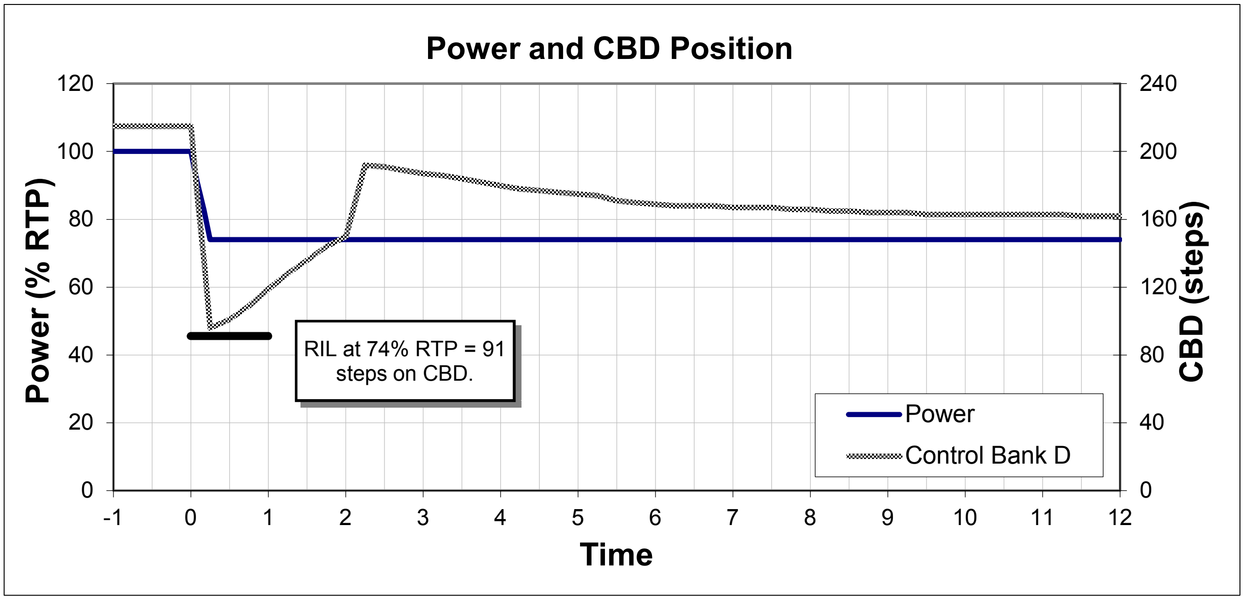
MOL PROJECTIONS - SIMULATOR USE ONLY

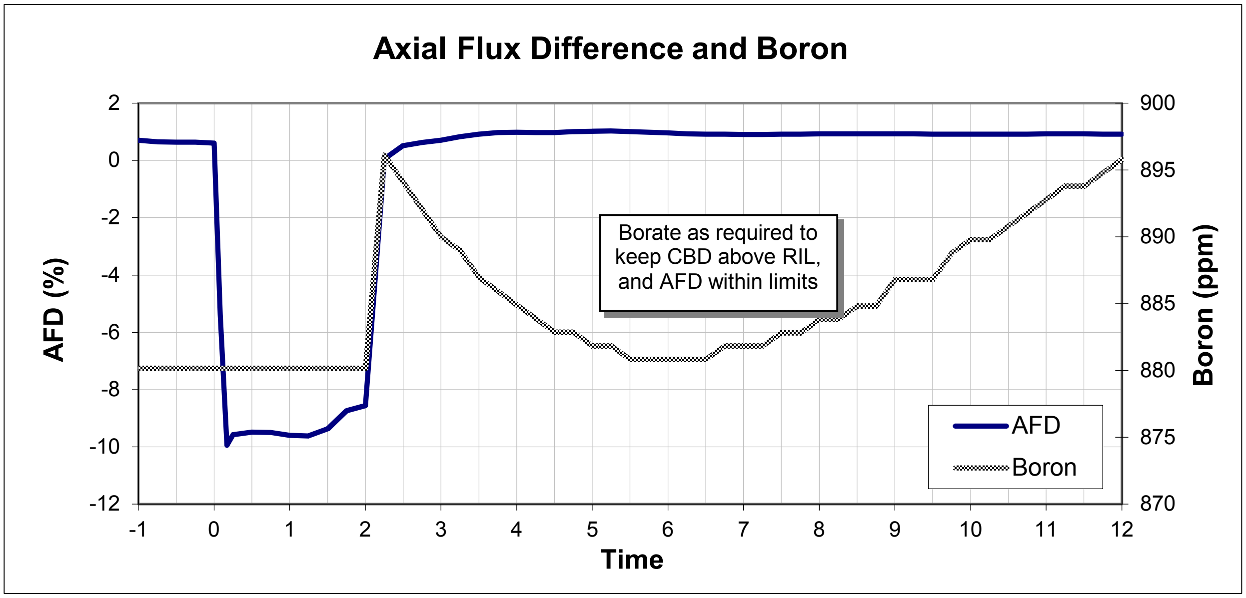
Basic Control Strategy:

A) A boration of 155 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 1200 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Runback to 800 MWe

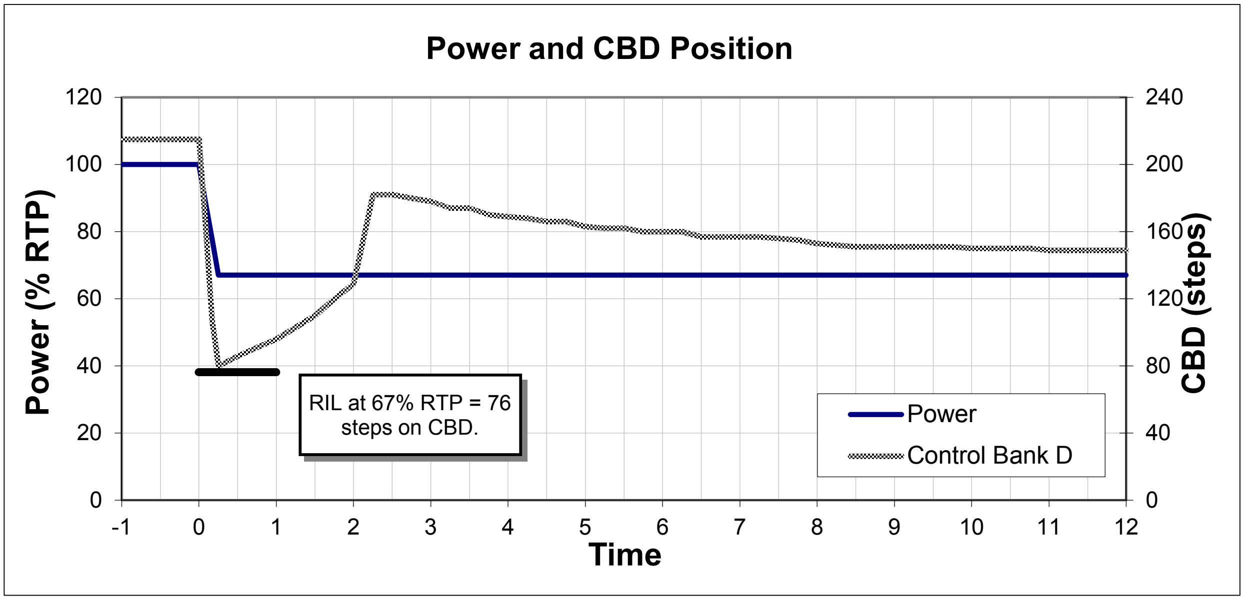
MOL PROJECTIONS - SIMULATOR USE ONLY

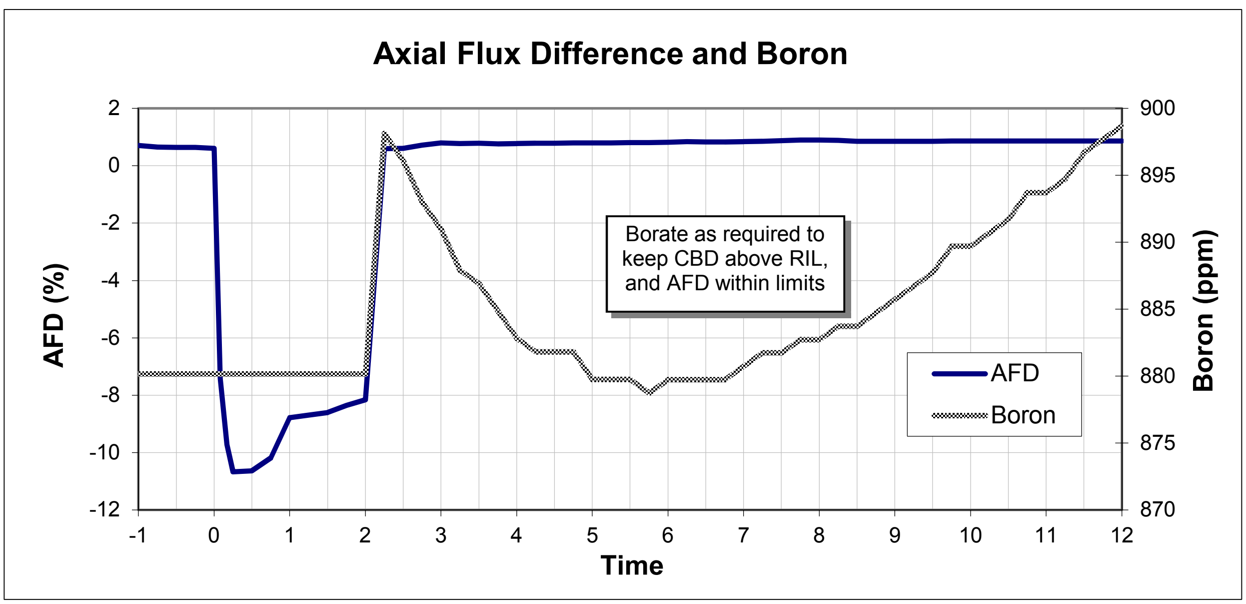
Basic Control Strategy:

A) A boration of 175 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 1500 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Runback to 700 MWe

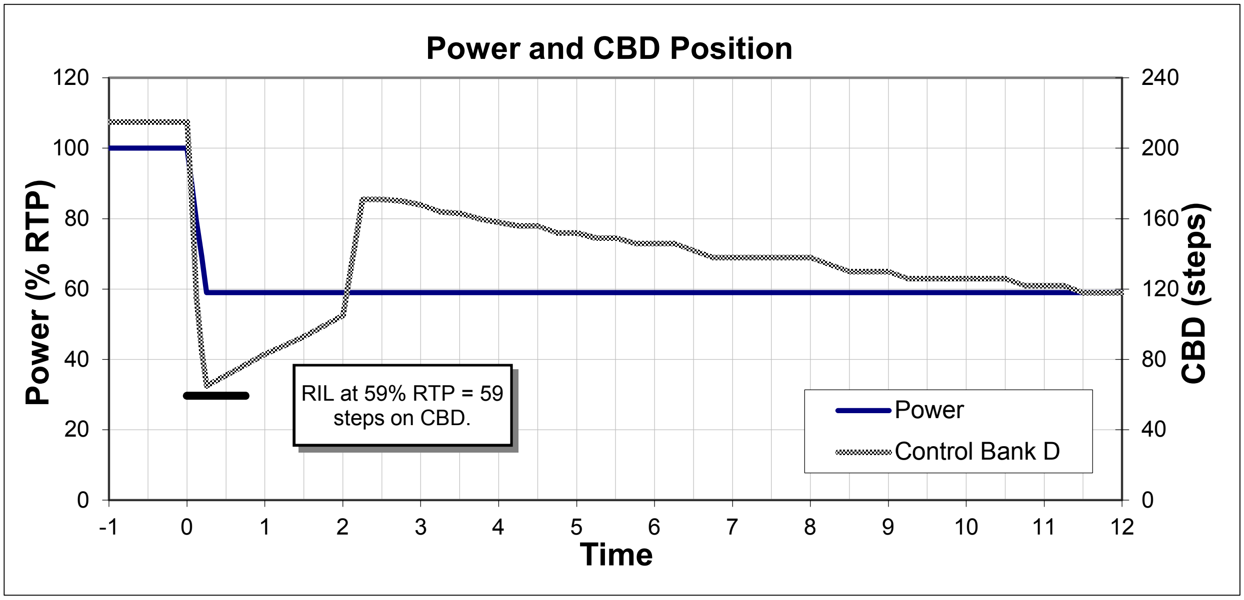
MOL PROJECTIONS - SIMULATOR USE ONLY

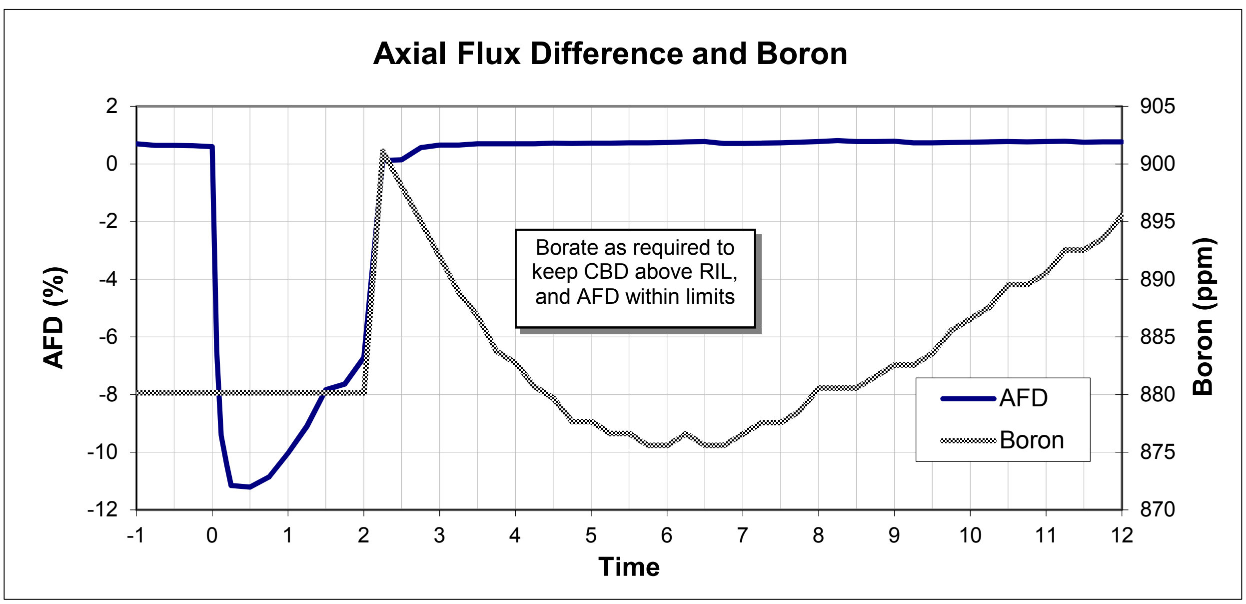
Basic Control Strategy:

A) A boration of 200 gallons should be initated soon after the runback. This will ensure rods are above RIL within 45 minutes and will likely be needed to restore Target AFD.

B) As rods are withdrawn due to boration, begin dilution when AFD reaches the Target value to maintain Target AFD. Total Dilution Estimate is 2000 gallons.

NOTE: Contact Core Performance Engineering following any Runback for additional support.





Reactivity Briefing Sheet for Downpower Boration Matrix

MOL PROJECTIONS - SIMULATOR USE ONLY

The boration/dilution estimates are based on BEACON predictions for maintaining Incore Axial Offset.

With deep rod insertion, it is expected AFD indications (based on Excore Detectors) will be less than the Incore value by ~2-4%. In this case, no immediate action is needed to restore AFD, but contact Core Performance.

Borate at a rate sufficient to allow ~15 minutes of mixing before the final power level is reached.

Contact Core Performance as soon as possible when planning ANY downpower for additional support.

Assumed Initial Conditions

Power	100	% RTP
CBD Position	215	steps
RCS Boron	864	ppm *(anticipated boron at middle of validity range)*

30 Minute Ramp Down Boration Estimates

	900 MWe	800 MWe	700 MWe	50% RTP
	(~74% RTP)	(~67% RTP)	(~59% RTP)	
Final CBD Position	*172 steps*	*161 steps*	*148 steps*	*123 steps*
Total Boration	*304 gal*	*384 gal*	*481 gal*	*561 gal*

Dilution in first hour to support maintaining reduced power, while holding Incore AFD on Target:

Followup Dilution (1st hour)	*1102 gal*	*1409 gal*	*1792 gal*	*2435 gal*
Ave Dilution Rate (1st hour)	*18.4 gpm*	*23.5 gpm*	*29.9 gpm*	*40.6 gpm*

Notes: Highlighted values: Max boration rate during downpower may be unable to maintain Target AFD. Restore and hold Target AFD as soon as possible following the Downpower.

2 Hour Ramp Down Boration Estimates

	900 MWe	800 MWe	700 MWe	50% RTP
	(~74% RTP)	(~67% RTP)	(~59% RTP)	
Final CBD Position	*172 steps*	*158 steps*	*142 steps*	*101 steps*
Total Boration	*191 gal*	*232 gal*	*286 gal*	*258 gal*

Dilution in first hour to support maintaining reduced power, while holding Incore AFD on Target:

Followup Dilution (1st hour)	*771 gal*	*1017 gal*	*1292 gal*	*1641 gal*
Ave Dilution Rate (1st hour)	*12.9 gpm*	*17 gpm*	*21.5 gpm*	*27.4 gpm*

1 Hour Rapid Shutdown (Ramp to 20% on Target AFD, 30 minute hold, trip)

	20% RTP
Final CBD Position	*79.2 steps*
Total Boration	*698 gal*

Notes:

After 30 minutes, no dilution (withdrawing rods to control power), holding at 20% RTP

CBD Position	*107.4 steps*	Incore AFD	*2.8 %*

UNIT SUPERVISOR RELIEF CHECKLIST

UNIT 1

OFF-GOING US: Unit Supervisor **SHIFT:** Night **DATE:** Today
ON-COMING US: ______ **SHIFT:** ______

PART I TO BE PREPARED BY THE OFF-GOING UNIT SUPERVISOR.

1.0 SHIFT ACTIVITIES:

1.1 Activities Completed This Shift:

Verified CT System is in standby per SOP-204 5.1.1

1.2 Activities In-progress:

MD AFW Pump 1-02 motor oil change

Maintaining power ~92% for Main Turbine testing

1.3 Planned Activities:

OPT-206 A when MDAFW work completes

SOP-204A 5.1.3 to recire the RWST via the recirculation header

2.0 PLANT AND EQUIPMENT STATUS:

2.1 Technical Specification or Related Equipment Summary

A1-17-0065 ->TS 3.7.5 AFW Condition B.1 - 72 hours for MDAFW 1-02 motor oil change (expected completion in 8 hours)

GEM on 1-HS-2450A

UNIT SUPERVISOR RELIEF CHECKLIST

2.2 **Non-Technical Specification Related Equipment Summary**

No equipment out of service.

3.0 **GENERAL INFORMATION:**

None

4.0 **END OF SHIFT REVIEW:**

LOGS – RO/BOP X LOGS-NEO X CLOSED eLCOARs ARCHIVED X
OPTS COMPLETD X DAILY ACTIVITIES LIST X LCOARs REVIEWED X
COMP ACTIONS REVIEWED X

PART II TO BE COMPLETED BY THE ON-COMING UNIT SUPERVISOR.

1.0 **CRITICAL PARAMETERS:**

MODE: 1 REACTOR POWER: 92 MWe: 1163
RCS TAVE: 585 °F CONTROL ROD POSITION 202 ON BANK D
C_B: 777 ppm RCS PRESS: 2235 psig

2.0 **STATUS REVIEW:**

	X	UNIT LOGS
[C]	X	* * LCOAR AND SYSTEMS IMPORTANT TO SAFETY STATUS [26082, 23486]
	X	UNIT DIFFERENCES (If last watch was on opposite unit)
	X	SHIFT ORDERS
	X	BOARD WALKDOWN
	X	* POD
[C]	X	CONDITIONAL SURVEILLANCE STATUS BOARD [23486]
	X	LOCATION OF SAFEGUARDS INFORMATION
	X	* RISK PROFILE FOR SHIFT

PROTECTED TRAIN [X] Train “A” [ ] Train “B”

* May be completed after turnover.
* * Each US’s (U1 & U2) status review is to include the U1 & Common LCOAR & SIS Logs for Common equipment.

SHIFT RELIEF: ______________________ / ______________ / ______________
ON-COMING US SIGNATURE DATE TIME

Unit Supervisor
OFF-GOING US SIGNATURE

____
ON-COMING FSS REVIEW

____
SHIFT MANAGER REVIEW