Examination Outline Cross-reference:	Level	RO	SRO
295001AA2.05	Tier #		1
Ability to determine and interpret the following as they apply to Partial or Complete Loss of Forced Core Flow Circulation: Jet pump operability.	Group #		1
	K/A #	295001AA2.05	
	Importance Rating	3.1	3.4

Proposed Question: **SRO #1**

Given the following conditions:

- Unit 1 is starting up following refueling on 12/17/2008.
- Power level is being held at 30% to allow maintenance on RFPT 1B.
- 1A Recirc VFD inadvertently tripped at 1400 due to human error locally at the VFD.
- 1A Recirc Pump was restarted at 1415.

Which ONE of the following describes the requirement for performing 1-SR-3.4.2.1, "Jet Pump Mismatch and Operability?"

Surveillance 1-SR-3.4.2.1, "Jet Pump Mismatch and Operability" is required to be performed NO LATER THAN ____(1)______.

a. 1815 on 12/17/2008

b. 1800 on 12/18/2008

c. 1415 on 12/18/2008

d. 1400 on 12/18/2008

Proposed Answer: **A**

Explanation:

a. Correct answer

b. Incorrect. The allowance for 24 hours is only appropriate if 4 hours have passed since the recirc pump was started and power level remained below 25%. In addition, the time limitation begins when the pump is started, not tripped.

c. Incorrect. The allowance for 24 hours is only appropriate if 4 hours have passed since the recirc pump was started AND power level remained below 25%.

d. Incorrect. The allowance for 24 hours is only appropriate if 4 hours have passed since the recirc pump was started and power level remained below 25%. In addition, the time limitation begins when the pump is started, not tripped.

Technical Reference(s): U1 TSR 3.4.2, U1 TSB 3.4.2, 1-OI-68 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New X 7/6/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 Jet Pumps

LCO 3.4.2 All jet pumps shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more jet pumps inoperable.	A.1 Be in MODE 3.	12 hours

Jet Pumps
3.4.2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	------------------------NOTES-------------------- 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 25% RTP. --- Verify at least one of the following criteria (a, b, or c) is satisfied for each operating recirculation loop: a. Recirculation pump flow to speed ratio differs by ≤ 5% from established patterns, and jet pump loop flow to recirculation pump speed ratio differs by ≤ 5% from established patterns. b. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns. c. Each jet pump flow differs by ≤ 10% from established patterns.	24 hours

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.2.1 (continued) Note 2 allows this SR not to be performed until 24 hours after THERMAL POWER exceeds 25% of RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.
REFERENCES	1. FSAR, Section 14.6.3. 2. GE Service Information Letter No. 330, "Jet Pump Beam Cracks," June 9, 1980. 3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984. 4. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

Examination Outline Cross-reference:	Level	RO	SRO
295006G2.2.42	Tier #		1
Ability to recognize system parameters that are entry-level conditions for Technical Specifications: Scram	Group #		1
	K/A #	295006G2.2.42	
	Importance Rating	3.9	4.6

Proposed Question: **SRO #2**

Given the following conditions:

- Unit 1 is operating at 100% rated power.
- Both Reactor Recirculation Pumps have tripped.
- A manual scram was initiated in accordance with 1-AOI-68-1A, "Recirc Pump Trip/Core Flow Decrease OPRMs Operable."

Which ONE of the following describes the relationship between the required actions of 1-AOI-68-1A and the required actions per Technical Specifications for the given conditions and the basis for that action?

The requirement to initiate a scram in accordance with 1-AOI-68-1A is ______(1)______ with respect to the required actions per Technical Specifications. The basis for that action is __________(2)__________.

	(1)	(2)
a.	consistent	the FSAR analysis for a DBA requires both recirc pumps to be operating.
b.	consistent	to place the plant in a MODE where the LCO does not apply.
c.	conservative	the FSAR analysis for a DBA requires both recirc pumps to be operating.
d.	conservative	to place the plant in a MODE where the LCO does not apply.

Proposed Answer: **D**

Explanation:

a. Part (1) is incorrect. A manual scram is conservative with respect to Tech Spec requirements. TSR 3.4.1.B provides 12 hours to be in Mode 3. Part (2) is also incorrect. The FSAR analysis "assumes" both recirc pumps are in operation but does not "require" this conditions provided adjustments are made to thermal limits with the required timeframe.

b. Part (1) is incorrect. Part (2) is correct. Although the actions required by 1-AOI-68-1A are conservative compared to Tech Specs, the end result is the same. Operation in Mode 3.

c. Part (1) is correct. Part (2) is also incorrect. The FSAR analysis "assumes" both recirc pumps are in operation but does not "require" this conditions provided adjustments are made to thermal limits with the required timeframe.

d. Correct answer

Technical Reference(s): 1-AOI-68-1A, U1 TSR 3.4.1 (Attach if not previously provided)

U1 TSB 3.4.1

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/6/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge X

Comprehension or Analysis

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 Recirculation Loops Operating

LCO 3.4.1 Two recirculation loops with matched flows shall be in operation.

OR

One recirculation loop may be in operation provided the following limits are applied when the associated LCO is applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," single loop operation limits specified in the COLR;

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," single loop operation limits specified in the COLR;

c. LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," Function 2.b (Average Power Range Monitors Flow Biased Simulated Thermal Power - High), Allowable Value of Table 3.3.1.1-1 is reset for single loop operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Requirements of the LCO not met.	A.1	Satisfy the requirements of the LCO.	24 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> No recirculation loops in operation.	B.1	Be in MODE 3.	12 hours

BFN Unit 1	Recirc Pump Trip/Core Flow Decrease OPRMs Operable	1-AOI-68-1A Rev. 0002 Page 6 of 12

4.0 OPERATOR ACTIONS

4.1 Immediate Actions

None

4.2 Subsequent Actions

[1] **IF** both Recirc Pumps are tripped in modes 1 or 2, **THEN** (Otherwise N/A)

[1.1] **SCRAM** the Reactor. ☐

CAUTION

[NER/C] Failure to restart Reactor Recirculation pumps in a timely manner may result in exceeding the differential temperature limit for pump start and subsequently require plant depressurization to avoid exceeding pressure-temperature limits for the reactor vessel. [SER 93-005]

[1.2] **RESTART** affected Reactor Recirculation pumps. Refer to 1-OI-68 Section 8.0. ☐

[2] **IF** the ΔT between the Rx vessel bottom head temperature and the moderator temperature precludes restart of a Recirc pump, **OR** forced Recirculation flow CANNOT be established for any reason, **THEN** (Otherwise NA)

[2.1] **INITIATE** a plant cooldown to prevent exceeding the pressure limit for the Rx vessel bottom head temperature indicated on REACTOR VESSEL METAL TEMPERATURE, 1-TR-56-4 pt. 10 (Panel 1-9-47) and based on Tech Specs Figure 3.4.9-1. ☐

[2.2] **INFORM** the Unit Supervisor, Tech Spec 3.4.1 requires the Reactor be placed in Mode 3 in 12 hours. **REFER TO** 1-GOI-100-12A and Tech Specs 3.4.1.B. ☐

BASES (continued)

LCO	Two recirculation loops are required to be in operation with their flows matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. With the limits specified in SR 3.4.1.1 not met, the recirculation loop with the lower flow must be considered not in operation. With only one recirculation loop in operation, modifications to the required APLHGR Limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, 'MINIMUM CRITICAL POWER RATIO (MCPR)"), and APRM Flow Biased Simulated Thermal Power-High Setpoint (LCO 3.3.1.1) may be applied to allow continued operation consistent with the assumptions of References 7 and 8.
APPLICABILITY	In MODES 1 and 2, requirements for operation of the Reactor Coolant Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur. In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

BASES

ACTIONS (continued)

B.1

With no recirculation loops in operation while in MODES 1 or 2 or the Required Action and associated Completion Time of Condition A not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

Examination Outline Cross-reference:	Level	RO	SRO
295016G2.2.3	Tier #		1
Knowledge of the design, procedural and operational differences between units: Control Room Abandonment.	Group #		1
	K/A #	295016G2.2.3	
	Importance Rating	3.8	3.9

Proposed Question: **SRO # 3**

Given the following plant conditions:

- Unit 1/2 control room has been evacuated due to a toxic gas intrusion.
- Control has been established at both Backup Control Panels.
- All four Unit 1/2 diesel generators have been started.
- Both units have initiated a cooldown at < 90 ^{O}F.
- The Shift manager has directed both units to initiate and maximize Suppression Pool Cooling.

Which ONE of the following describes the required RHR pump lineup for each unit and the basis for that lineup?

The RHR pump lineup is _____(1)_____. The basis for the required lineup is to _____(2)_____.

	(1)	(2)
A.	Unit-1 Div I, Unit-2 Div II	equalize loading of all four 4Kv Shutdown Boards
B.	Unit-1 Div I, Unit-2 Div II	ensure PREFERRED pumps for LPCI injection remain available.
C.	Unit-1 Div II, Unit-2 Div I	equalize loading of all four 4Kv Shutdown Boards
D.	Unit-1 Div II, Unit-2 Div I	ensure PREFERRED pumps for LPCI injection remain available.

Proposed Answer: **C**

Explanation:

a. Part (1) is incorrect. This would be the correct lineup for LPCI pumps under Common Accident conditions, but is reversed for operation from the Backup Control Panel. Part (2) is correct.

b. Part (1) is incorrect. This would be the correct lineup for LPCI pumps under Common Accident conditions, but is reversed for operation from the Backup Control Panel. Part (2) is incorrect. Although the lineup for Suppression Pool Cooling does not involve PREFERRED RHR pumps for the given unit, actions farther along in the AOI direct opening the breakers for the remaining two RHR pumps so they would not be available for injection.

c. Correct answer.

d. Part (1) is correct. Part (2) is incorrect. Although the lineup for Suppression Pool Cooling does not involve PREFERRED RHR pumps for the given unit, actions farther along in the AOI direct opening the breakers for the remaining two RHR pumps so they would not be available for injection.

Technical Reference(s): 1/2-AOI-100-2, OPL171.044 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/13/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge X

Comprehension or Analysis

10 CFR Part 55 Content: 55.41

55.43 X

Comments: The basis for the divisional separation is primarily historical. Unit-2 was the first of the three BFN units to be re-started following an extended 3 unit shutdown. As such, Division I was established for use following control room abandonment. When Unit-3 followed, being essentially identical to Unit-2 with a separate control room and DGs, Division I was also used for control room abandonment. The Unit-1 re-start had to take into consideration the current divisional assignment of Unit-2 as well as reliability of available power. As such, Unit-1 was assigned Division II to allow equal loading of the two remaining 4Kv Shutdown Boards not being used by Unit-2. What makes this such a challenging question is that the divisional assignments are opposite of those for a Common Accident scenario.

BFN Unit 1	Control Room Abandonment	1-AOI-100-2 Rev. 0016 Page 15 of 79

4.2 Unit 1 Subsequent Actions (continued)

[15.4] **VERIFY OPEN** RHR SYSTEM II MIN FLOW VLV, 1-FCV-074-0030, at either of the following:

- 480V RMOV Bd 1B, Compt. R11E, RHR SYSTEM II MIN FLOW VLV, 1-BKR-074-0030 **OR** ☐
- Rx Bldg - SE Quad - El 541' local control switch RHR SYS II MIN FLOW VALVE, 1-HS-074-0030B. (Otherwise N/A) ☐

[15.5] **PLACE** RHR PUMP 1B, 1-HS-074-0028C, in CLOSE at 4160V Shutdown Bd C, Compt. 17, to start RHR PUMP 1B. ☐

[15.6] **PLACE** RHR SYS II SUPPR CHBR/POOL ISOL VLV, 1-HS-074-0071C in OPEN at 480V RMOV Bd 1B, Compt. 11C. ☐

[15.7] **ESTABLISH** RHR system flow between 7,000 and 10,000 gpm as follows:

[15.7.1] **MONITOR** RHR SYS II TOTAL FLOW, 1-FI-74-79 at Panel 1-25-32. ☐

[15.7.2] **THROTTLE OPEN** RHR SYS II SUPPR POOL CLG/TEST VLV using 1-HS-074-0073C at 480V RMOV Bd 1B, Compt. R11C. ☐

[15.7.3] **WHEN** RHR SYS II TOTAL FLOW, 1-FI-74-79 indicates between 7,000 and 10,000 gpm, **THEN**

DIRECT the operator to stop throttling 1-HS-074-0073C. ☐

[15.7.4] **VERIFY CLOSED** RHR SYSTEM II MIN FLOW VLV, 1-FCV-074-0030, at either of the following:

- 480V RMOV Bd 1B, Compt. R11E, RHR SYSTEM II MIN FLOW VLV, 1-BKR-074-0030 **OR** ☐
- Rx Bldg - SE Quad - El 541' local control switch RHR SYSTEM II MIN FLOW VALVE, 1-HS-074-0030B. (Otherwise N/A) ☐

BFN Unit 1	Control Room Abandonment	1-AOI-100-2 Rev. 0016 Page 16 of 79

4.2 Unit 1 Subsequent Actions (continued)

[15.8] **MONITOR** SUPPR POOL TEMPERATURE, 1-TI-64-55B, at Panel 1-25-32 **and MAINTAIN** temperature less than 120°F. ☐

NOTE
Communication between 4160V Shutdown Bd D and 480V RMOV Bd 1B is necessary for establishing RHRSW flow and to prevent exceeding 53 amps on RHRSW Pump D2.

[15.9] **IF** additional Suppression Pool cooling is necessary, **THEN** (Otherwise N/A)

START a second RHRSW and RHR pump as follows:

[15.9.1] **PLACE** RHRSW PUMP D2 MOTOR, 0-HS-023-0027C in CLOSE at 4160V Shutdown Bd D, Compt. 15 to start RHRSW Pump D2. ☐

[15.9.2] **THROTTLE OPEN** RHR HX 1D RHRSW OUTLET VLV, using 1-HS-023-0052C at 480V RMOV Bd 1B, Compt. 15C. ☐

[15.9.3] **WHEN** between 48 and 52 amps on RHR SERVICE WATER PUMP C1, **THEN**

STOP throttling RHR HX 1D RHRSW OUTLET VLV, 1-HS-023-0052C. ☐

[15.9.4] **PLACE** RHR PUMP 1D, 1-HS-074-0039C, in CLOSE at 4160V Shutdown Bd D, Compt. 16, to start RHR Pump 1D. ☐

[15.9.5] **MONITOR** RHR SYS II TOTAL FLOW, 1-FI-74-79 at Panel 1-25-32. ☐

[15.9.6] **THROTTLE OPEN** RHR SYS II SUPPR POOL CLG/TEST VLV using 1-HS-074-0073C at 480V RMOV Bd 1B, Compt. R11C. ☐

[15.9.7] **WHEN** RHR SYS II TOTAL FLOW, 1-FI-74-79 is at or below 13,000 gpm, **THEN**

DIRECT operator to stop throttling 1-HS-074-0073C. ☐

BFN Unit 2	Control Room Abandonment	2-AOI-100-2 Rev. 0051 Page 16 of 95

4.2 **Unit 2 Subsequent Actions (continued)**

[15] **INITIATE** RHR Suppression Pool Cooling as follows:

NOTE
Communication between 4160V Shutdown Bd B and 480V RMOV Bd 2A is necessary for establishing RHRSW flow and to prevent exceeding 53 amps on RHRSW Pump C2.

[15.1] At 4160V Shutdown Bd B, compt. 15, **PLACE** RHRSW PUMP C2 MOTOR, 0-HS-23-12C, in CLOSE to start RHR SERVICE WATER PUMP C2. ☐

[15.2] At 480V RMOV Bd 2A, compt. 18C, **THROTTLE OPEN** RHR HX 2C OUTLET VLV, 2-HS-023-0040C. ☐

[15.3] **WHEN** between 48 and 52 amps on RHR SERVICE WATER PUMP C2, **THEN**

STOP throttling, RHR HX 2C OUTLET VLV, 2-HS-023-0040C. ☐

[15.4] **VERIFY OPEN** RHR SYSTEM I MINIMUM FLOW VALVE, 2-FCV-74-7, at either of the following:

- 480V RMOV Bd 2D, compt. 5E, RHR SYSTEM I MINIMUM FLOW VLV, **OR**
- Rx Bldg - SW Quad - El 541' local control switch RHR SYSTEM I MINIMUM FLOW VALVE, 2-HS-74-7B. ☐

[15.5] At 4160V Shutdown Bd B, compt. 17, **PLACE** RHR PUMP 2C, 2-HS-074-0016C, in CLOSE to start RHR PUMP 2C. ☐

[15.6] At 480V RMOV Bd 2A, compt. 11C, **PLACE** RHR SYSTEM I SUPP POOL SPRAY/TEST ISOL VLV, 2-HS-74-57C, in OPEN. ☐

BFN Unit 2	Control Room Abandonment	2-AOI-100-2 Rev. 0051 Page 18 of 95

4.2 Unit 2 Subsequent Actions (continued)

NOTE
Communication between 4160V Shutdown Bd A and 480V RMOV Bd 2A is necessary for establishing RHRSW flow and to prevent exceeding 53 amps on RHRSW Pump A2.

[15.9] **IF** additional Suppression Pool cooling is necessary, **THEN** (Otherwise N/A)

START a second RHRSW and RHR pump as follows:

[15.9.1] At 4160V Shutdown Bd A, compt. 17, **PLACE** RHRSW PUMP A2 MOTOR, 0-HS-023-0005C, in CLOSE to start RHR SERVICE WATER PUMP A2. ☐

[15.9.2] At 480V RMOV Bd 2A, compt. 17C, **THROTTLE OPEN** RHR HX 2A OUTLET VLV, 2-HS-023-0034C. ☐

[15.9.3] **WHEN** between 48 and 52 amps on RHR SERVICE WATER PUMP A2, **THEN**

STOP throttling RHR HX 2A OUTLET VLV, 2-HS-023-0034C. ☐

[15.9.4] At 4160V Shutdown Bd A, compt. 19, **PLACE** RHR PUMP 2A, 2-HS-074-0005C, in CLOSE to start RHR PUMP 2A. ☐

[15.10] **MAINTAIN** RHR system flow at or below 13,000 gpm as follows:

[15.10.1] At Panel 2-25-32, **MONITOR** RHR SYS I TOTAL FLOW, 2-FI-74-79. ☐

[15.10.2] At 480V RMOV Bd 2A, compt. 19C5, **THROTTLE** RHR SYSTEM I TEST VLV, 2-HS-074-0059C. ☐

[15.10.3] **WHEN** RHR SYS I TOTAL FLOW, 2-FI-74-79 is at or below 13,000 gpm, **THEN**

DIRECT operator to stop throttling 2-HS-74-59C. ☐

BFN Unit 1	Control Room Abandonment	1-AOI-100-2 Rev. 0016 Page 3 of 79

1.0 PURPOSE

This instruction provides symptoms and operator actions for safe shut down and cooldown to cold conditions (Mode 4) of Unit 1 Reactor from locations outside the Unit 1 Control Room in the event of a Main Control Room evacuation.

1.1 Scope

This procedure can **NOT** be properly executed for, and does **NOT** support, shutting down the Reactor during any type of accident.

The provisions of this instruction are adequate and proper for the following EOI entry conditions that may be encountered while executing Control Room abandonment:

- 1-EOI-1 Flow Chart, RPV Control

  Reactor Water Level less than +2.0 inches

  Reactor Pressure High above 1073 psig.

- 1-EOI-2 Flow Chart, Primary Containment Control

  Suppression Pool Temperature above 95°F

  Suppression Pool Level above -1 inch

1.2 Responsibilities

A. The Shift Manager/Unit Supervisor (SRO) has primary responsibility for implementation and coordination of this instruction.

B. For ALL situations, the Shift Manager/Unit Supervisor (SRO) makes an assessment of the situation and attempts corrective measures to preclude evacuation. If abandonment becomes necessary, the Shift Manager/Unit Supervisor (SRO) has the authority to assign personnel necessary to implement this instruction.

C. When the Control Room becomes available, the Shift Manager/Unit Supervisor (SRO) makes an assessment of the situation, gradually transfers control back to normal, re-establishes the condenser as a heat sink, and returns the Condensate System to service.

Examination Outline Cross-reference:

295025G2.1.19

Ability to use plant computer to evaluate system or component status: High Reactor Pressure.

	RO	SRO
Level	RO	SRO
Tier #		1
Group #		1
K/A #	295025G2.1.19	
Importance Rating	3.9	3.8

Proposed Question: **SRO # 4**

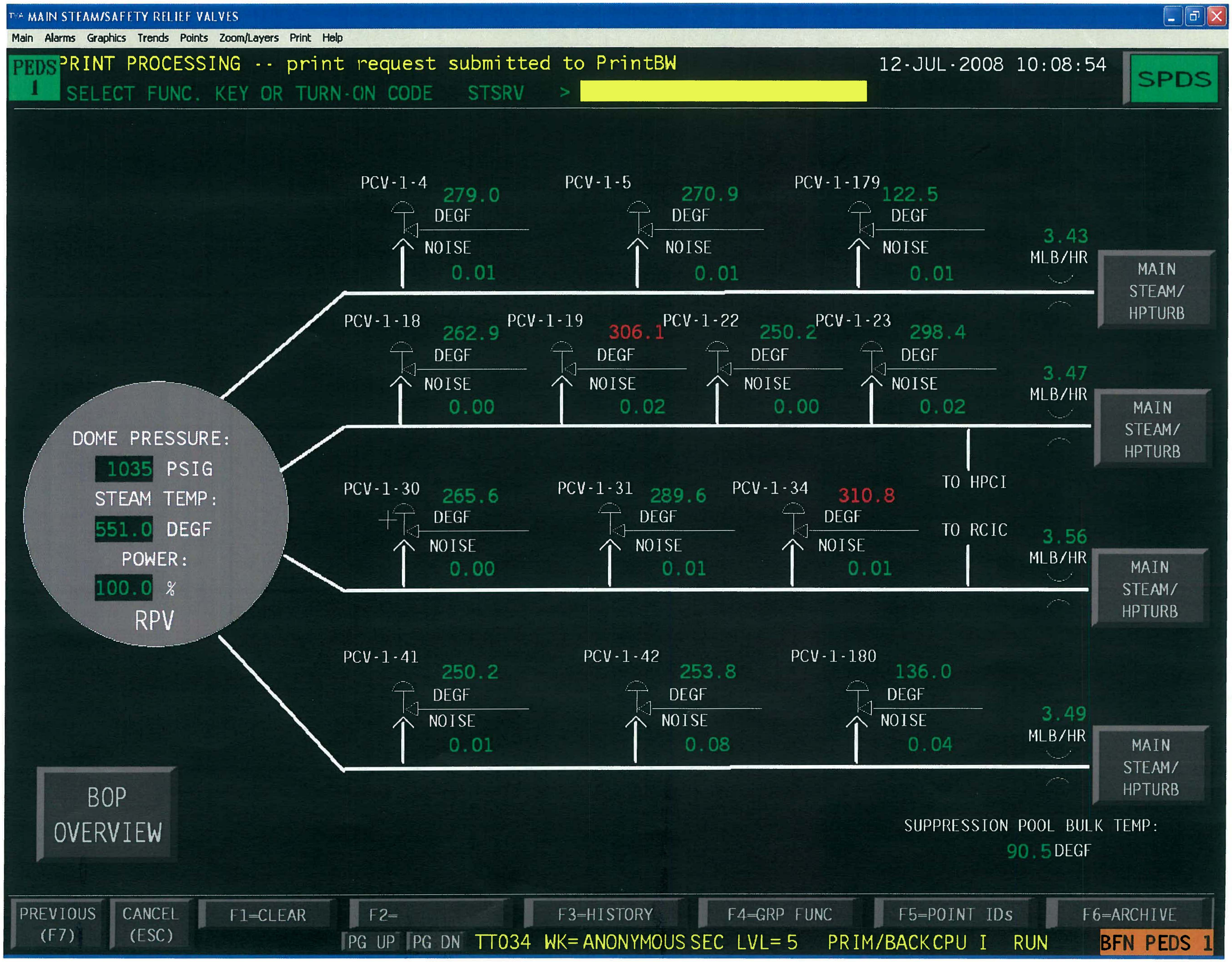
Given the attached printout of U1 PEDS Main Steam/Safety Relief Valves:

Which ONE of the following describes the status of U1 Main Steam Relief Valves (MSRV) and any required actions resulting from this condition?

MSRVs 1-19 and 1-34 are _____(1)_____ . The required action for this condition is to ____________(2)____________.

REFERENCE PROVIDED ON THE FOLLOWING PAGE.

	(1)	(2)
A.	INOPERABLE	be in Mode 3 in 12 hours and Mode 4 in 36 hours.
B.	INOPERABLE	be in Mode 3 in 12 hours and reduce reactor steam dome pressure to $\leq$ 150 psig in 36 hours.
C.	OPERABLE	enter an "INFORMATION ONLY" LCO in accordance with OPDP-8, "LCO Tracking."
D.	OPERABLE	maintain Suppression Pool temperature < 95 ^{O}F in accordance with 1-OI-74, "RHR System."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SPDS
PCV-1-4 279.0 DEGF NOISE 0.01
PCV-1-5 270.9 DEGF NOISE 0.01
PCV-1-179 122.5 DEGF NOISE 0.01
3.43 MLB/HR
MAIN STEAM/ HPTURB
PCV-1-18 262.9 DEGF NOISE 0.00
PCV-1-19 306.1 DEGF NOISE 0.02
PCV-1-22 250.2 DEGF NOISE 0.00
PCV-1-23 298.4 DEGF NOISE 0.02
3.47 MLB/HR
MAIN STEAM/ HPTURB
DOME PRESSURE: 1035 PSIG
STEAM TEMP: 551.0 DEGF
POWER: 100.0 %
RPV
PCV-1-30 265.6 DEGF NOISE 0.00
PCV-1-31 289.6 DEGF NOISE 0.01
PCV-1-34 310.8 DEGF NOISE 0.01
TO HPCI
TO RCIC
3.56 MLB/HR
MAIN STEAM/ HPTURB
PCV-1-41 250.2 DEGF NOISE 0.01
PCV-1-42 253.8 DEGF NOISE 0.08
PCV-1-180 136.0 DEGF NOISE 0.04
3.49 MLB/HR
MAIN STEAM/ HPTURB
BOP OVERVIEW
SUPPRESSION POOL BULK TEMP: 90.5 DEGF
PREVIOUS (F7)
CANCEL (ESC)
F1=CLEAR
F2=
F3=HISTORY
F4=GRP FUNC
F5=POINT IDs
F6=ARCHIVE
PG UP PG DN TT034 WK=ANONYMOUS SEC LVL=5 PRIM/BACK CPU I RUN
BFN PEDS 1

Proposed Answer: **D**

Explanation:

a. Part (1) is incorrect. The MSRVs in question are both OPERABLE. Part (2) is also incorrect. This action is based on Tech Spec 3.4.3.A if more than one MSRV is inoperable.

b. Part (1) is incorrect. The MSRVs in question are both OPERABLE. They are not considered INOPERABLE based solely on leakage. Part (2) is also incorrect. This action is based on Tech Spec 3.5.1.G if two or more ADS MSRVs are inoperable.

c. Part (1) is correct based on (a) and (b) above. Part (2) is incorrect. This action is based on INOPERABLE equipment that does not apply to an LCO.

d. Correct Answer.

Technical Reference(s):	U1 TSR 3.4.3, 3.5.1, 1-OI-74	(Attach if not previously provided)
	OPDP-8	

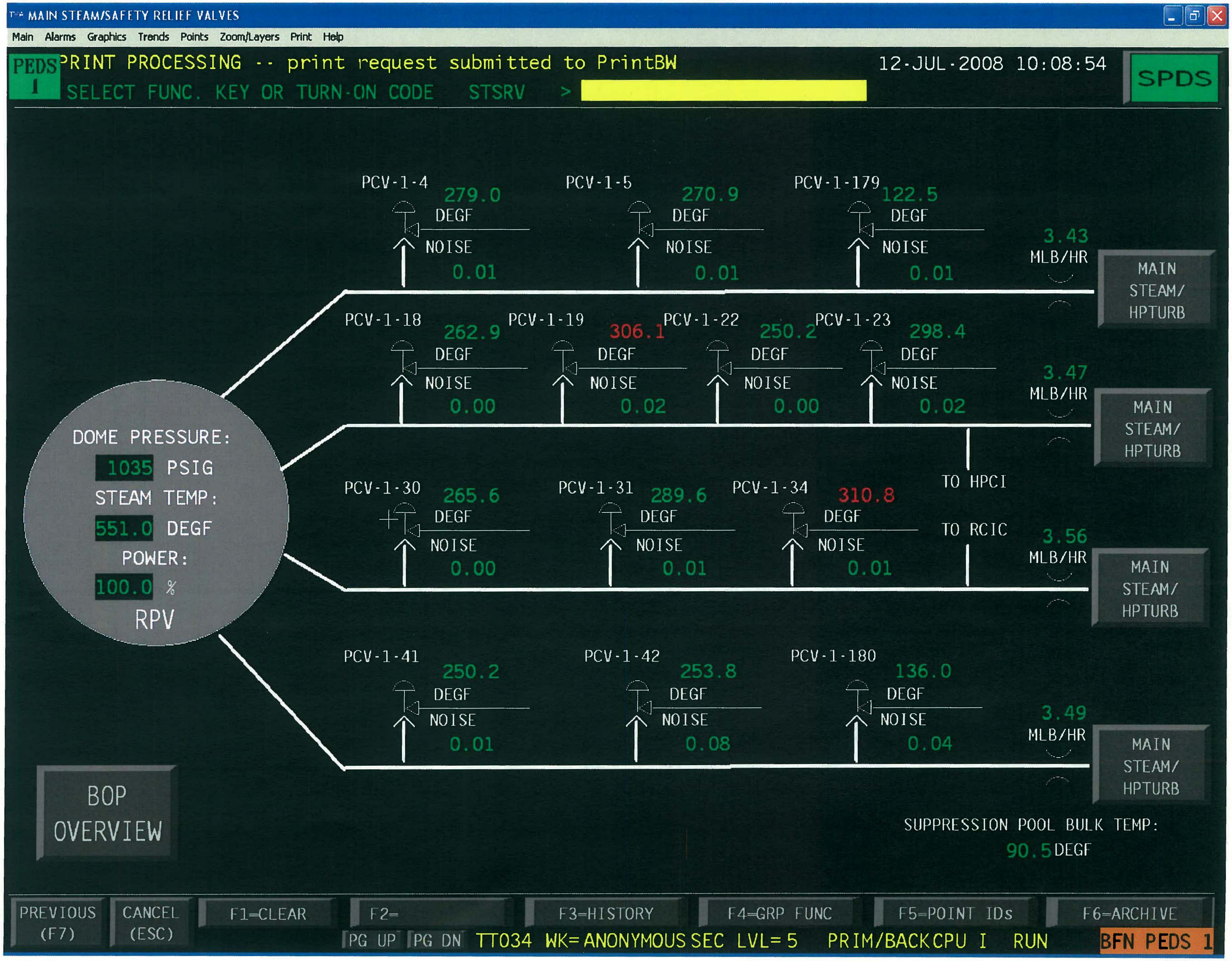
Proposed references to be provided to applicants during examination: U-1 ICS computer printout of Main Steam/Safety Relief Valve page Attachment 1.

Question Source:	Bank #		
	Modified Bank #		(Note changes or attach parent)
	New	7/13/2008 RMS	
Question History:	Last NRC Exam		

Question Cognitive Level:	Memory or Fundamental Knowledge	
	Comprehension or Analysis	X

10 CFR Part 55 Content:	55.41	
	55.43	X

Comments: In order to answer the first part of this question, the candidate must first determine whether the MSRVs are ADS or non-ADS valves. He must then determine whether the given indications from the plant computer satisfy the requirements for OPERABILITY according to Tech Spec bases. Therefore, only half of the first part of this question can be answered using RO technical knowledge.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Main Alarms Graphics Trends Points Zoom/Layers Print Help
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PCV-1-5 270.9 DEGF NOISE 0.01
PCV-1-179 122.5 DEGF NOISE 0.01
3.43 MLB/HR
MAIN STEAM/ HPTURB
PCV-1-18 262.9 DEGF NOISE 0.00
PCV-1-19 306.1 DEGF NOISE 0.02
PCV-1-22 250.2 DEGF NOISE 0.00
PCV-1-23 298.4 DEGF NOISE 0.02
3.47 MLB/HR
MAIN STEAM/ HPTURB
DOME PRESSURE: 1035 PSIG
STEAM TEMP: 551.0 DEGF
POWER: 100.0 %
RPV
PCV-1-30 265.6 DEGF NOISE 0.00
PCV-1-31 289.6 DEGF NOISE 0.01
PCV-1-34 310.8 DEGF NOISE 0.01
TO HPCI
TO RCIC
3.56 MLB/HR
MAIN STEAM/ HPTURB
PCV-1-41 250.2 DEGF NOISE 0.01
PCV-1-42 253.8 DEGF NOISE 0.08
PCV-1-180 136.0 DEGF NOISE 0.04
3.49 MLB/HR
MAIN STEAM/ HPTURB
BOP OVERVIEW
SUPPRESSION POOL BULK TEMP: 90.5 DEGF
PREVIOUS (F7)
CANCEL (ESC)
F1=CLEAR
F2=
F3=HISTORY
F4=GRP FUNC
F5=POINT IDs
F6=ARCHIVE
PG UP PG DN TT034 WK=ANONYMOUS SEC LVL=5 PRIM/BACKCPU I RUN
BFN PEDS 1

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 Safety/Relief Valves (S/RVs)

LCO 3.4.3 The safety function of 12 S/RVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required S/RVs inoperable.	A.1 Be in MODE 3.	12 hours
	AND	
	A.2 Be in MODE 4.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition C, D, E, or F not met.	G.1 Be in MODE 3. AND G.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours
H. Two or more low pressure ECCS injection/spray subsystems inoperable for reasons other than Condition A. OR HPCI System and one or more ADS valves inoperable.	H.1 Enter LCO 3.0.3.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. HPCI System inoperable.	C.1	Verify by administrative means RCIC System is OPERABLE.	Immediately
	AND		
	C.2	Restore HPCI System to OPERABLE status.	14 days
D. HPCI System inoperable. AND Condition A entered.	D.1	Restore HPCI System to OPERABLE status.	72 hours
	OR		
	D.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours
E. One ADS valve inoperable.	E.1	Restore ADS valve to OPERABLE status.	14 days
F. One ADS valve inoperable. AND Condition A entered.	F.1	Restore ADS valve to OPERABLE status.	72 hours
	OR		
	F.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES	The overpressure protection system must accommodate the most severe pressurization transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs), followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 1). For the purpose of the analyses, 12 S/RVs are assumed to operate in the safety mode. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the Design Basis Event. Reference 2 discusses additional events that are expected to actuate the S/RVs. From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. S/RVs satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).
LCO	The safety function of 12 S/RVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 1 and 2). The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function). The S/RV setpoints are established to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the

(continued)

3.3.7 Documentation

A. Immediate Operability determinations should be documented and sufficiently addressed so an individual knowledgeable in the technical discipline associated with the condition would be expected to understand its basis.

B. The documentation for immediate determinations need not be extensive. Plant record systems, such as operator logs or the corrective action program, are often sufficient.

C. Communication of the basis for an immediate determination to following shifts is also important. Operability may be based on conditions that subsequently change. The person making the initial determination may or may not be present at the plant when those conditions change. Subsequent personnel need to have sufficient information to ensure that if conditions that were important to a previous operability determination have changed that they are able to reassess the validity of the determination and/or take appropriate actions.

3.4 TS LCO Evaluations

3.4.1 General Guidelines

A. When equipment identified in TS is made or becomes inoperable, existing plant/unit conditions may require LCOs be entered.

B. LCOs are entered if, for existing plant/unit conditions, TS require action(s) to be taken.

C. LCOs are exited when the equipment is returned to operable status or when the plant/unit is put into a condition where TS no longer require action(s) to be taken.

WBN, BFN Only

NOTE
TS 3.0.6 and 5.7.2.18 (WBN)/5.5.11 (BFN) addresses LCO entry relative to support systems and supported systems.

D. TS action requirements may change as the aggregate of inoperable equipment changes. Determination of TS action(s) and the quantity of LCOs to be entered are based on the aggregate of inoperable systems, equipment, and components.

E. Multiple LCOs shall be entered and logged if equipment is inoperable or removed from service and more than one TS LCO action is required to be taken.

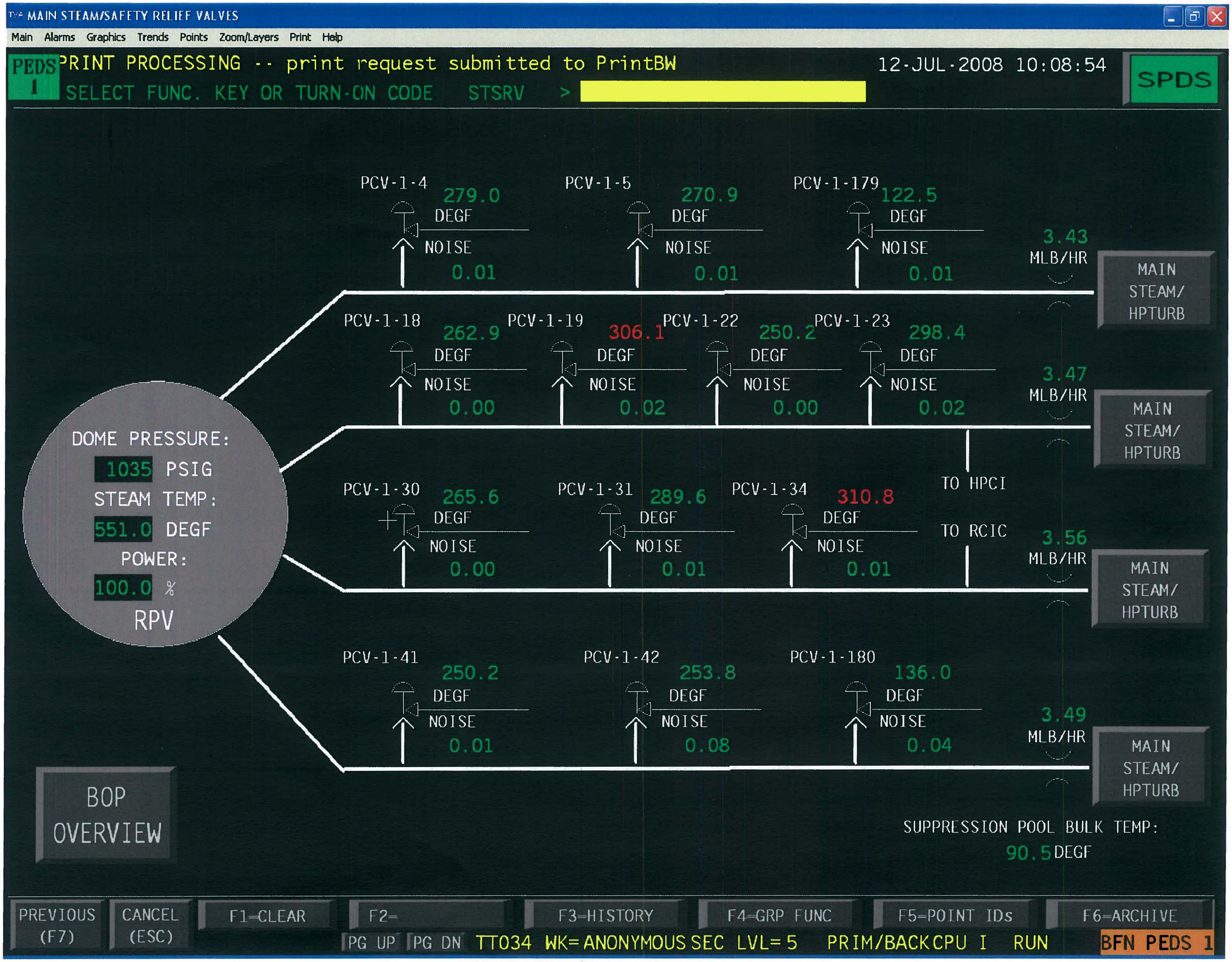
F. If equipment is identified or made inoperable that does not apply to an LCO based on the current plant conditions, an "Information Only" LCO should be entered into the Unit Log or LCO Tracking Log, as appropriate. The "Information Only" LCO entry should contain information similar to an "Active" LCO with possibly the exception of the LCO expiration date not being required.

During plant shutdown/outages, it is not required to utilize INFORMATION ONLY LCOs for conditions that are applicable only in other modes which are controlled by other plant instructions (i.e., general operating instructions, surveillance instructions etc.).

REFERENCE MATERIAL

Provided to

CANDIDATE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Main Alarms Graphics Trends Points Zoom/Layers Print Help
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PCV-1-4 279.0 DEGF NOISE 0.01
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3.43 MLB/HR
MAIN STEAM/ HPTURB
PCV-1-18 262.9 DEGF NOISE 0.00
PCV-1-19 306.1 DEGF NOISE 0.02
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3.47 MLB/HR
MAIN STEAM/ HPTURB
DOME PRESSURE: 1035 PSIG
STEAM TEMP: 551.0 DEGF
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TO HPCI
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PCV-1-42 253.8 DEGF NOISE 0.08
PCV-1-180 136.0 DEGF NOISE 0.04
3.49 MLB/HR
MAIN STEAM/ HPTURB
BOP OVERVIEW
SUPPRESSION POOL BULK TEMP: 90.5 DEGF
PREVIOUS (F7)
CANCEL (ESC)
F1=CLEAR
F2=
F3=HISTORY
F4=GRP FUNC
F5=POINT IDs
F6=ARCHIVE
PG UP PG DN TT034 WK= ANONYMOUS SEC LVL= 5 PRIM/BACK CPU I RUN
BFN PEDS 1

Examination Outline Cross-reference:	Level	RO	SRO
295038EA2.04	Tier #		1
Ability to determine and interpret the following as they apply to High Off-site Release Rate: Source of Off-site Release.	Group #		1
	K/A #	295038EA2.04	
	Importance Rating	4.1	4.5

Proposed Question: **SRO #5**

Unit 3 was operating at 100% rated power when a Main Turbine trip resulted in the following indications:

- OG PRETREATMENT RADIATION HIGH (9-3A W5) in alarm.
- MAIN STEAM LINE RADIATION HIGH-HIGH (9-3A W27) in alarm.
- TURBINE BLDG AREA RADIATION HIGH (9-3A W29) in alarm.
- TURB BLDG ROOF EXH VENT RADIATION HIGH (9-3A W18) in alarm.
- Reactor Water Level (-) 25 inches and recovering.
- Reactor Pressure 900 psig and lowering.
- MSIVs are open
- 3-TS-1-60A indication 140 ^{0}F and rising.
- The Radcon Manager reports dose readings at the site boundary are 1.5 REM TEDE.

Which ONE of the following is the cause of these indications and the action required to mitigate the event?

Plant conditions indicate a _____(1)_____ has occurred. The Unit Supervisor must _____(2)_____ to mitigate this event.

	(1)	(2)
A.	main steam line break in the Turbine Bldg	enter 3-EOI-3, "Secondary Containment Control."
B.	main steam line break in the Turbine Bldg	enter 0-EOI-4, "Radioactivity Release Control."
C.	Group I auto isolation failure with fuel damage	enter 3-EOI-3, "Secondary Containment Control."
D.	Group I auto isolation failure with fuel damage	enter 0-EOI-4, "Radioactivity Release Control."

Proposed Answer: **B**

Explanation:

a. Part (1) is correct. Part (2) would be correct if the break occurred inboard of the MSIVs rather than outboard. This is only determined by analyzing the annunciators and recognizing that 3-TS-1-60A has not yet reached the Group I setpoint. Steam Tunnel relief panels will blow out to relieve steam to the Turbine Building, thus preventing temperature from isolating the MSIVs as quickly.

b. Correct answer

c. Part (1) is incorrect only because the MSIVs have not received an AUTO closure signal yet. However, the MSL Radiation High-High annunciator indicates the need to immediately close the MSIVs. In addition, 3-TS-1-60A is one indicator used to determine 3-EOI-3 entry conditions, but has not yet reached the required value.

d. Part (1) is incorrect as stated in (c) above. Part (2) is incorrect as stated in (a) above.

Technical Reference(s): 3-ARP-9-3A, 3-ARP-9-3D, 0-EOI-4 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/7/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

BFN Unit 3	Panel 9-3 3-XA-55-3A	3-ARP-9-3A Rev. 0036 Page 10 of 51

OG PRETREATMENT RADIATION HIGH 3-RA-90-157A 5	Sensor/Trip Point:	HI
	3-RM-90-157	1595 MR/HR

(Page 1 of 2)

Sensor Location: RE-90-157, Turb Bldg OG pretreatment sample chamber, El 565', T-14 B-LINE

Probable Cause:
A. High radiation in the off-gas pretreatment system.
B. Resin trap failure (RWCU or Cond Demin).
C. Possible fuel element failure.
D. Sensor malfunction.

Automatic Action: None

Operator Action:

A. **VERIFY** high radiation on following:
1. OFFGAS PRETREATMENT RADIATION recorder, 3-RR-90-157 on Panel 3-9-2. ☐
2. OFFGAS RADIATION recorder, 3-RR-90-160 on Panel 3-9-2. ☐
3. OG PRETREATMENT RAD MON RTMR, 3-RM-90-157 on Panel 3-9-10. ☐
4. OFFGAS RAD MON RTMR, 3-RM-90-160 on Panel 3-9-10. ☐

B. **CHECK** off-gas flow normal. ☐

C. **CHECK** following radiation recorders and associated radiation monitors:
1. MAIN STEAM LINE RADIATION, 3-RR-90-135 on Panel 3-9-2. ☐
2. OFFGAS POST-TREATMENT RADIATION, 3-RR-90-265 on Panel 3-9-2. ☐
3. STACK GAS RADIATION, 0-RR-90-147 on Panel 1-9-2. ☐

D. **NOTIFY** RADCON. ☐

E. **REQUEST** Chemistry perform radiochemical analysis to determine source. ☐

Continued on Next Page

BFN Unit 3	Panel 9-3 3-XA-55-3A	3-ARP-9-3A Rev. 0036 Page 11 of 51

OG PRETREATMENT RADIATION HIGH 3-RA-90-157A, Window 5
(Page 2 of 2)

Operator Action: (Continued)

F. **REFER TO** 0-SI-4.8.B.1.a.1 and 1(2)(3)-SR-3.4.6.1(A) for ODCM compliance and to determine if power level reduction is required. ☐

G. **IF** directed by Unit Supervisor, **THEN**
REDUCE reactor power to maintain off-gas radiation within ODCM limits. ☐

H. **IF** ODCM limits are exceeded, **THEN**
REFER TO EPIP-1. ☐

References: 3-45E620-3 3-47E610-90-1 GE 3-729E814-4 3-SIMI-90B

BROWNS FERRY	EMERGENCY CLASSIFICATION PROCEDURE EVENT CLASSIFICATION MATRIX	EPIP-1

MSL / OFFGAS RADIATION	LOSS OF DECAY HEAT REMOVAL	
Description	Description	
1.4-U		
Valid MAIN STEAM LINE RADIATION HIGH-HIGH alarm, RA-90-135C OR Valid OG PRETREATMENT RADIATION HIGH alarm, RA-90-157A. OPERATING CONDITION: Mode 1 or 2 or 3		UNUSUAL EVENT
	1.5-A	
	Reactor moderator temperature can NOT be maintained below 212° F whenever Technical Specifications require Mode 4 conditions or during operations in Mode 5. OPERATING CONDITION: Mode 4 or 5	ALERT
	1.5-S CURVE US	
	Suppression Pool temperature, level and RPV pressure can NOT be maintained in the safe area of Curve 1.5-S. OPERATING CONDITION: Mode 1 or 2 or 3	SITE EMERGENCY
		GENERAL EMERGENCY

BFN Unit 3	Panel 9-3 3-XA-55-3A	3-ARP-9-3A Rev. 0036 Page 39 of 51

MAIN STEAM LINE RADIATION HIGH-HIGH 3-RA-90-135C

27

(Page 1 of 1)

Sensor/Trip Point:

3-RM-90-136 Three times the normal full power background.
3-RM-90-137

Sensor Location: Panel 3-9-10 in the control room.

Probable Cause:

A. Radiation is three times normal full power background.
B. Sensor malfunctions.
C. SI (SR) in progress.

Automatic Action:

A. Mechanical vacuum pumps trip.
B. Vacuum pump suction valves 3-FCV-66-36 and 3-FCV-66-40 close.

Operator Action:

A. **VERIFY** alarm on 3-RM-90-136 thru 137 on Panel 3-9-10. ☐
B. **CONFIRM** main steam line radiation level on recorder 3-RR-90-135, Panel 3-9-2. ☐
C. **IF** alarm is **VALID** and scram has **NOT** occurred, **THEN PERFORM** the following:

   IF core flow is above 60%, **THEN**
   1. **LOWER** core flow to between 50-60%. ☐
   2. **MANUALLY SCRAM** the Reactor. ☐
   3. **REFER TO** 3-AOI-100-1. ☐

D. **IF** plant conditions **DO NOT** require the execution of 3-C-5, Power/Level Control, **THEN** **VERIFY** the MSIV's CLOSED. ☐
E. **NOTIFY** RADCON. ☐
F. **VERIFY** actions OF 3-ARP-9-3A window 7 have been completed. ☐
G. **IF** Technical Specifications limits are exceeded, **THEN** REFER TO EPIP-1. ☐

References: 3-47E610-90-1 GE 730E915-9,10 3-4-45E620-5

BFN Unit 3	Panel 9-3 3-XA-55-3A	3-ARP-9-3A Rev. 0036 Page 42 of 51

TURBINE BLDG AREA RADIATION HIGH 3-RA-90-1E

29

(Page 1 of 1)

Sensor/Trip Point:

RI-90-5A	10 MR/HR
RI-90-6A	10 MR/HR
RI-90-7A	10 MR/HR
RI-90-10A	10 MR/HR
RI-90-11A	10 MR/HR
RI-90-12A	10 MR/HR
RI-90-16A	10 MR/HR
RI-90-17A	10 MR/HR
RI-90-18A	10 MR/HR
RI-90-19A	10 MR/HR
RI-90-31A	10 MR/HR

Sensor Location:

RE-90-5, Generator operating floor	TB El. 617'	T-14 D-LINE
RE-90-6, RFP operating floor	TB El. 617'	T-12 F-LINE
RE-90-7, Turbine operating floor	TB El. 617'	T-15 K-LINE
RE-90-11, Turbine Breeze way	TB El. 586'	T-12 B-LINE
RE-90-12, FW Heater area	TB El. 586'	T-12 D-LINE
RE-90-15, Decontamination Chmb.	TB El. 578'	T-12 B-LINE
RI-90-16, Hotwell pump area	TB El. 557'	T-14 C-LINE
RI-90-17, Condenser room area	TB El. 557'	T-14 F-LINE
RI-90-18, Condenser corridor	TB El. 557'	T-12 F-LINE
RI-90-19, Outside Steam Tunnel	TB El. 565'	T-15 J-LINE
RI-90-31, Raw Cooling Water Pumps	TB El. 557'	T-13 C-LINE

Probable Cause: Radiation levels have risen above alarm set point.

Automatic Action: None

Operator Action:

A. **DETERMINE** area with high radiation level on Panel 3-9-11. (Alarm on Panel 3-9-11 will automatically reset if radiation level lowers below setpoint.) ☐

B. **IF** the TSC is **NOT** manned, **THEN**
USE public address system to evacuate area where high airborne conditions exist. ☐

Continued on Next Page

BFN Unit 3	Panel 9-3 3-XA-55-3A	3-ARP-9-3A Rev. 0036 Page 43 of 51

TURBINE BLDG AREA RADIATION HIGH 3-RA-90-1E, Window 29
(Page 2 of 2)

Operator Action: (Continued)

C. **IF** the TSC is manned, **THEN** **REQUEST** the TSC to evacuate non-essential personnel from affected areas. ☐
D. **NOTIFY** RADCON. ☐
E. **MONITOR** other parameters providing input to this annunciator frequently as these parameters will be masked from alarming while this alarm is sealed in. ☐
F. **IF** alarm is due to sensor malfunction, **THEN** REFER TO 0-OI-55. ☐

References: 3-45E620-3 3-45E610-90-1 GE 730E356-1

REV 0025
Panel 9-3
3-XA-55-3D

UNIT 3
3-ARP-9-3D
Page 25

MAIN STEAM LINE
LEAK DETECTION
TEMP HIGH
3-TA-1-60

24

SENSOR/TRIP POINT:

3-TIS-1-60A
3-TS-1-60B through D 160°F

ELEVATED, BUT NOT HIGH ENOUGH TO INITIATE THE ALARM.

SENSOR LOCATION: Panel 3-9-3, Main Control Room, El 617', Panel 3-9-21, Main Control Rm, El 617'

PROBABLE CAUSE:
1. Main Steam, RWCU, Feedwater, RCIC, or HPCI Disch(Only with HPCI in service and elevated Suppression Pool water Temp.) Line Break.
2. Turb or Rx Bldg cooling/ventilation out of service.
3. Sensor malfunction.
4. Steam Vault Exhaust Booster Fan out of service.

AUTOMATIC ACTION: Impending MSIV Isolation at 189°F area temp.

OPERATOR ACTION:

NOTES:

1. 3-LI-64-159A, SUPPR POOL WATER LEVEL may give erroneous indications due to High Temperatures experienced by the Instrument during a Main Steam high energy line break in Secondary Containment.

2. The following Steps may be performed in any order or concurrently as necessary.

1. **CHECK** the following temperature indications:
   - MN STEAM TUNNEL TEMP temperature indicator, 3-TIS-1-60A on Panel 3-9-3.
   - Temperature Switches 3-TS-1-60B, -60C, or -60D window(s) on Panel 3-9-21.
   - RWCU Piping in the Main Steam Tunnel temperature indicators, 3-TIS-69-834A(B)(C)(D), Auxiliary Instrument Room Panels 9-83(84)(85)(86) OR ICS 'HPTURB' mimic.

2. **CHECK** the following flow indications:
   - MAIN STEAM LINE FLOW A(B)(C)(D), 3-FI-46-1(2)(3)(4) on Panel 3-9-5
   - RFW FLOW LINE A(B), 3-FI-3-78A(78B) on Panel 3-9-5.
   - RFP 3A(3B)3C) flow indicators, 3-FI-3-20(13)(6) on Panel 3-9-6.

3. **IF** RCIC is not in service AND 3-FI-71-1A(B), RCIC STEAM FLOW indicates flow, **THEN**

   ISOLATE RCIC AND **VERIFY** Temperatures lowering.

CONTINUED ON NEXT PAGE

REV 0025 UNIT 3
Panel 9-3 3-ARP-9-3D
3-XA-55-3D Page 26

MAIN STEAM LINE LEAK DETECTION TEMP HIGH 3-TA-1-60

OPERATOR ACTION (Window 24 Continued)

4. **CHECK** for elevated RAD Levels on the following Instruments:

   - 3-RM-90-20, CRD-HCU West.
   - 3-RM-90-29, Suppression Pool.

5. **IF** HPCI is injecting with elevated Suppression Pool Temperature, **THEN**

   CONSIDER securing HPCI to determine if it is the source of the leak.

6. **IF** Rx Bldg main steam tunnel temperature is above 160°F on 3-TIS-1-60A on Panel 3-9-3, **THEN**

   PERFORM the following:

   a. ENTER 3-EOI-3 Flowchart.
   b. **VERIFY** Rx Zone fans, 3-HS-64-11A at Panel 3-9-25, in fast speed.
   c. **VERIFY** Steam Vault Exhaust Booster Fan in service. REFER TO 3-OI-30B.

7. **IF** turbine building main steam tunnel temperature is above 160°F on 3-TS-1-60B, -60C, or -60D on Panel 3-9-21, **THEN**

   DISPATCH personnel to 480V AC Turb Bldg Vent Bd 3A (TB, El 617') to verify TB fans and the Mechanical Spaces Exhaust Fan running.

REFERENCES: 3-45E620-2; 3-47E610-1-1; GE 920D351; Tech Specs 3.3.1.1, Reactor Protection System (RPS) Instrumentation; 3.3.6.1, Primary Containment Isolation Instrumentation.

BROWNS FERRY	EMERGENCY CLASSIFICATION PROCEDURE EVENT CLASSIFICATION MATRIX	EPIP-1

MAIN STEAM LINE BREAK	LIQUID EFFLUENT	
Description	Description	
4.2-U Main Steam Line break outside Primary Containment with isolation. OPERATING CONDITION: Mode 1 or 2 or 3	4.3-U Liquid release rate exceeds 20 times ECL as determined by chemistry sample AND Release duration exceeds or will exceed 60 minutes. OPERATING CONDITION: ALL	UNUSUAL EVENT
	4.3-A Liquid release rate exceeds 2000 times ECL as determined by chemistry sample AND Release duration exceeds or will exceed 15 minutes. OPERATING CONDITION: ALL	ALERT
4.2-S Unisolable Main Steam Line break outside Primary Containment. OPERATING CONDITION: Mode 1 or 2 or 3		SITE EMERGENCY
		GENERAL EMERGENCY

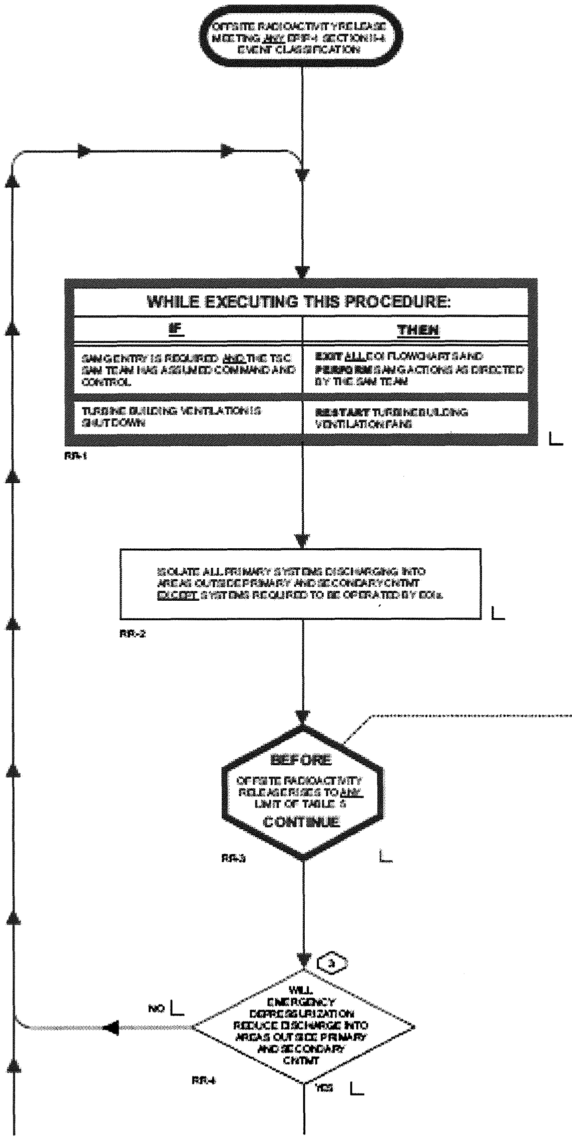


TABLE 5
OFFSITE RADIOACTIVITY RELEASE CLASSIFICATION LIMITS FOR GENERAL EMERGENCY

TYPE	MONITORING METHOD	LIMIT REFERENCE
GASEOUS RELEASE RATE	STACK NOBLE GAS RELEASE (WRGERMS)	BFN EPIP GENERAL EMERGENCY CLASSIFICATION LIMIT
SITE BOUNDARY RADIATION READING	FIELD ASSESSMENT TEAM	BFN EPIP GENERAL EMERGENCY CLASSIFICATION LIMIT
SITE BOUNDARY IODINE-131	FIELD ASSESSMENT TEAM	BFN EPIP GENERAL EMERGENCY CLASSIFICATION LIMIT
ACTUAL OR PROJECTED DOSE CONSEQUENCES AT OR BEYOND THE SITE BOUNDARY (TEDE)	DOSE ASSESSMENT	BFN EPIP GENERAL EMERGENCY CLASSIFICATION LIMIT
ACTUAL OR PROJECTED DOSE CONSEQUENCES AT OR BEYOND THE SITE BOUNDARY (THYROID CDE)	DOSE ASSESSMENT	BFN EPIP GENERAL EMERGENCY CLASSIFICATION LIMIT

Examination Outline Cross-reference:	Level	RO	SRO
600000AA2.07	Tier #		1
Ability to determine and interpret the following as they apply to Plant Fire On Site: Whether malfunction is due to common-mode electrical failures.	Group #		1
	K/A #	600000AA2.07	
	Importance Rating	2.6	3.0

Proposed Question: **SRO # 6**

Given Unit 2 at 100% rated power:

While performing rounds, the U2 Rx Bldg AUO discovered 2-HS-74-158 on 480V RMOV Board 2B in the "SHUTDOWN" position for Suppression Pool Suction valves 2-FCV 74-24 and 2-FCV-74-35.

Which ONE of the following describes the current status of the suction path for RHR Loop II and the action required?

Operation of the suction valves from the control room is ______(1)______. The Unit Supervisor must ______(2)______.

	(1)	(2)
A.	unavailable	restore RHR to OPERABLE in 7 days per Tech Spec 3.5.1.A
B.	unavailable	return 2-HS-74-158 to NORMAL in 7 days per Appendix R
C.	available	restore RHR to OPERABLE in 7 days per Tech Spec 3.5.1.A
D.	available	return 2-HS-74-158 to NORMAL in 7 days per Appendix R

Proposed Answer: **D**

Explanation:

a. Part (1) is incorrect. The NORMAL position of 2-HS-74-158 prevents operation of the valves from any location to prevent a common-mode electrical failure due to a fire. The SHUTDOWN position allows operation from the control room. Part (2) is incorrect. RHR Tech Spec OPERABILITY is not affected by the position of 2-HS-74-158. This is only an Appendix R issue.

b. Part (1) is incorrect. The NORMAL position of 2-HS-74-158 prevents operation of the valves from any location to prevent a common-mode electrical failure due to a fire. The SHUTDOWN position allows operation from the control room. Part (2) is correct.

c. Part (1) is correct. The SHUTDOWN position allows operation from the control room. Part (2) is incorrect. RHR Tech Spec OPERABILITY is not affected by the position of 2-HS-74-158. This is only an Appendix R issue.

d. Correct answer

Technical Reference(s):	FPR Volume 1 Section 4, U2 TSR 3.5.1	(Attach if not previously provided)
	OPL171.044	

Proposed references to be provided to applicants during examination: None

Question Source:	Bank #		
	Modified Bank #		(Note changes or attach parent)
	New	7/7/2008 RMS	
Question History:	Last NRC Exam		

Question Cognitive Level:	Memory or Fundamental Knowledge	
	Comprehension or Analysis	X

10 CFR Part 55 Content:	55.41	
	55.43	X

Comments: I evaluated this as C/A for two reasons. First, this question is answered without references. Second, what is actually tested involves determining whether the Appendix R switch impacts the OPERABILITY of RHR in accordance with 3.5.1. The bases of TSR 3.5.1 defines a LPCI sub-system as two pumps, piping, and **valves** to transfer water. The candidate must determine if the suction valves are considered OPERABLE by Tech Specs if they are considered INOPERABLE by Appendix R or vice versa. A determination must be made that RHR will still perform its intended function by Tech Specs by transferring water from the Suppression Pool to the RPV, but will NOT perform its required function by Appendix R which is to prevent a common-mode electrical failure from preventing LPCI injection from RHR Loop II.

Manual #: Fire Protection Report Vol. 1	PLANT: BFN	UNIT(s):1/2/3	PAGE 462 of 915
TITLE: Appendix R Safe Shutdown Program		SECTION: 4	REV: 0

The listed compensatory measure in the Unit 1, 2 & 3 tables due to equipment degredation or the compensatory measures due to lack of spatial separation per 9.3.11.G.1.a of the Fire Protection Plan may be removed/revised if:

- the affected unit is brought to COLD SHUTDOWN, or
- an engineering analysis is performed, this program is changed and the Safe Shutdown Instructions are changed to provide an alternative shutdown path or
- a different compensatory measure or combination of measures is established (e.g., additional administrative controls, operator briefings, temporary procedures, interim strategies, operator manual actions, temporary fire barriers, temporary detection or suppression systems). An engineering analysis of the alternative measure should incorporate risk insights regarding the location, quantity and type of combustible material in the fire area; the presence of ignition sources and their likelihood of occurrence; the automatic fire suppression and fire detection capability in the fire area; the manual suppression capability in the fire area; and the human error probability where applicable. (Reference 5)

Compensatory Measure A will be documented and tracked in accordance with Attachment A of this instruction.

COMPENSATORY MEASURES

A. Restore the equipment function in 7 days or provide equivalent shutdown capability by one of the following methods.

1) A temporary alteration in accordance with plant procedures that allows the equipment to perform its intended function, or

2) A fire watch in accordance with the site impairment program in the affected areas/zones as specified in Section III.

Note:
Fire watch requirements in the Turbine Building (FA #25) and Control Building (FA #16) may be evaluated on a case by case basis due to the large size of these areas. For example, fire watches in the Turbine Building can be limited to within 20 feet of the south wall (near M-Line wall on EL 565' and 586') or the Intake Pumping Station due to the location of the RHRSW power cables in the areas. No Safe Shutdown circuits are located in any other location within the Turbine building. Control Building areas, even though not separated by fire resistive barriers, provide substantial protection against the spread of fire due to installed fire suppression systems and concrete floor slabs and walls. The potential of fire spread between control building compartments and the turbine building compartments has been evaluated in Section 3.0 of the IPEEE Fire Induced Vulnerability Evaluations for Units 1-3 (Reference A16 Section 3). These evaluations may be reviewed to determine the extent of fire watches.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS - Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

-----NOTE-----
LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable. OR One low pressure coolant injection (LPCI) pump in both LPCI subsystems inoperable.	A.1	Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	7 days[1]

(continued)

[1] - This Completion Time may be extended to 14 days on a one-time basis. This temporary approval expires June 1, 2005.

INSTRUCTOR NOTES

1. Valve Interlocks — Obj. V.B.10.

   a. RHR pump suction from Suppression Pool — Obj. V.C.5. (74-1, 74-12, 74-24, 74-35) TP-15 and 16

      (1) No automatic closing or opening interlocks

      (2) Valve cannot be opened unless the corresponding pump Shutdown Cooling suction valve is fully closed (Interlock cannot be bypassed).

      (3) App. R mod. Added NORMAL/SHUTDOWN SW to control circuit. — Obj. V.D.8. Prevents Operations from any location.

         - Switch 2-74-157 (480 RMOV 2A) must be in SHUTDOWN to operate 2-74-1/12/48.
         - Switch 2-74-158 (480 RMOV 2B) must be placed in SHUTDOWN to operate 2-74-24/35.
         - Switch 3-74-24 (480 RMOV 3B) must be in SHUTDOWN to operate 3-74-24.
         - Switch 1-74-158(480 RMOV 1B) must be in SHUTDOWN to operate 1-74-24/35
         - Switch 1-74-157 (480 RMOV 1A) must be in SHUTDOWN to operate 1-74-1/12

      (4) "EMERGENCY" position allows operation at breaker only, but does not bypass in-line valve interlock — U1: 74-24/35 U2/3: 74-1/12

      (5) Interlock with RHR pump - Must be a suction path available to either start pump or pump will trip if running and suction path isolates.

BASES

BACKGROUND (continued)

at 0.2 seconds when offsite power is available and B, C, and D pumps approximately 7, 14, and 21 seconds afterwards and if offsite power is not available all pumps 7 seconds after diesel generator power is available). When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the CS System without spraying water in the RPV.

LPCI is an independent operating mode of the RHR System. There are two LPCI subsystems (Ref. 2), each consisting of two motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the corresponding recirculation loop.

The two LPCI pumps and associated motor operated valves in each LPCI subsystem are powered from separate 4 kV shutdown boards. Both pumps in a LPCI subsystem inject water into the reactor vessel through a common inboard injection valve and depend on the closure of the recirculation pump discharge valve following a LPCI injection signal. Therefore, each LPCI subsystem's common inboard injection valve and recirculation pump discharge valve are powered from one of the two 4 kV shutdown boards associated with that subsystem. The ability to provide power to the inboard injection valve and the recirculation pump discharge valve from two independent 4 kV shutdown boards ensures that a single failure of a diesel generator (DG) will not result in the failure of both LPCI pumps in one subsystem.

Examination Outline Cross-reference:	Level	RO	SRO
700000G2.1.23	Tier #		1
Ability to perform specific system and integrated plant procedures during all modes of plant operation. Generator Voltage and Electric Grid Disturbances.	Group #		1
	K/A #	700000G2.1.23	
	Importance Rating	4.3	4.4

Proposed Question: **SRO # 7**

Unit-2 is at 95% rated power with the following conditions:

- Trinity 1 500 Kv line has been removed from service to perform maintenance on switchyard breaker 5234.
- Main Generator reactive load is 110 Mvars outgoing.
- System voltage is 505 Kv.
- System frequency is 59.97 Hz.
- TVA Transmission System Load Coordinator has just declared an Emergency Load Curtailment Plan (ELCP) for the TVA transmission network.

Which ONE of the following describes the required action per plant procedures and the status of off-site power circuits to the Browns Ferry Nuclear Plant?

Direct the Unit Operator to ______(1)______. Off-site power circuits to Browns Ferry ______(2)______.

	(1)	(2)
A.	raise reactor power to 100% in accordance with 0-AOI-57-1F, "Emergency Load Curtailment."	are NOT qualified.
B.	raise reactive load to 200 Mvars in accordance with 0-AOI-57-1E, "Grid Instability."	are NOT qualified.
C.	raise reactor power to 100% in accordance with 0-AOI-57-1F, "Emergency Load Curtailment."	remain qualified
D.	raise reactive load to 200 Mvars in accordance with 0-AOI-57-1E, "Grid Instability."	remain qualified.

Proposed Answer: **B**

Explanation:

a. Part (1) is incorrect. Raising power is directed by 0-AOI-57-1E only if grid frequency is less than 59.85 Hz. Since the initiating condition for declaring an ELCP is excessive grid loading, raising power may eventually be addressed with the Load Coordinator, but is not required per procedure at this time. Part (2) is correct since entry into 0-AOI-57-1F is based on notification that off-site power sources are no longer QUALIFIED.

b. Correct answer.

c. Part (1) is incorrect as stated in (a) above. Part (2) is incorrect. Although the Trinity 1 line is out of service, two QUALIFIED off-site power sources are available UNTIL the ELCP was declared.

d. Part (1) is correct. System voltage less than 507 Kv requires raising Mvars to 200 in accordance with 0-AOI-57-1E to aid in restoring voltage. Part (2) is incorrect as stated in (c) above.

Technical Reference(s):	0-AOI-57-1E, 0-AOI-57-1F	(Attach if not previously provided)
	U2 TSR 3.8.1	

Proposed references to be provided to applicants during examination: None

Question Source:	Bank #		
	Modified Bank #		(Note changes or attach parent)
	New	7/12/2008 RMS	
Question History:	Last NRC Exam		

Question Cognitive Level:	Memory or Fundamental Knowledge	
	Comprehension or Analysis	X

10 CFR Part 55 Content:	55.41	
	55.43	X

Comments: The actions to raise power and reactive load are both appropriate to assist in mitigating the given conditions, however the stem specifically requires actions per plant procedures. Only raising reactive load is procedurally directed for the given conditions. The Tech Spec action determination requires the candidate to recall the basis for declaring an ELCP as well as recognition that one 500 Kv transmission line out of service does not necessarily place the unit in 3.8.1.A. In fact, the Trinity 1 line should not have been approved for maintenance if sufficient QUALIFIFED off-site sources were not verified before hand.

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources - Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System;

b. Unit 1 and 2 diesel generators (DGs) with two divisions of 480 V load shed logic and common accident signal logic OPERABLE; and

c. Unit 3 DG(s) capable of supplying the Unit 3 4.16 kV shutdown board(s) required by LCO 3.8.7, "Distribution Systems - Operating."

APPLICABILITY: MODES 1, 2, and 3.

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 Verify power availability from the remaining OPERABLE offsite transmission network. <u>AND</u>	1 hour <u>AND</u> Once per 8 hours thereafter (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One division of 480 V load shed logic inoperable.	C.1	Restore required division of 480 V load shed logic to OPERABLE status.	7 days
D. One division of common accident signal logic inoperable.	D.1	Restore required division of common accident signal logic to OPERABLE status.	7 days
E. Two required offsite circuits inoperable.	E.1	Declare required feature(s) inoperable when the redundant required feature(s) are inoperable.	12 hours from discovery of Condition E concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	E.2	Restore one required offsite circuit to OPERABLE status.	24 hours

(continued)

BASES (continued)

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System, four separate and independent Unit 1 and 2 DGs (A, B, C, and D), and the Unit 3 DG(s) needed to support required Standby Gas Treatment (SGT) trains and Control Room Emergency Ventilation System (CREVS) trains are required to be OPERABLE. Two divisions of 480 V load shed logic and two divisions of CAS logic are required to be OPERABLE to support Unit 1 and 2 DG OPERABILITY and post-accident loads. Unit 3 Technical Specifications will require the operability of all Unit 3 DGs and provide appropriate compensatory actions for inoperable Unit 3 DGs in support of Unit 3 operations. To support the operation of Unit 1, the Unit 1 LCO for AC Sources - Operating also requires the necessary Unit 3 DG(s) to support SGT and CREVS required by LCO 3.8.7, Distribution Systems - Operating, for supplying the Unit 3 4.16 kV shutdown boards. These requirements ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an abnormal operational transient or a postulated DBA.

Qualified offsite circuits are those that are described in the FSAR, and are part of the licensing basis for the unit. Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the 4.16 kV shutdown boards.

(continued)

BFN Unit 0	Emergency Load Curtailment	0-AOI-57-1F Rev. 0001 Page 4 of 24

1.0 PURPOSE

A. This abnormal operating instruction provides guidance for responding to the load dispatcher contacting BFN and stating that the offsite circuits are unable to provide QUALIFIED offsite power to Browns Ferry Nuclear Plant.

2.0 SYMPTOMS

A. None

3.0 AUTOMATIC ACTIONS

A. None

BFN Unit 0	Emergency Load Curtailment	0-AOI-57-1F Rev. 0001 Page 5 of 24

4.0 OPERATOR ACTION

NOTE

If necessary, place keeping marks may be made directly in the Control Room copy of this instruction. **CONTACT** Management Services for a replacement copy when time permits.

4.1 Immediate Action

None

4.2 Subsequent Action

B. **IF** the load dispatcher contacts BFN and states the offsite circuits are unable to provide QUALIFIED offsite power to Browns Ferry Nuclear Plant, **THEN**

PERFORM the following: (Otherwise N/A)

[1.1] **ENTER** LCO 3.8.1 (or 3.8.2 as appropriate) ☐

[1.2] **MAKE** appropriate notifications in accordance with SPP-3.5, REGULATORY REPORTING REQUIREMENTS. ☐

[1.3] **INITIATE** OPDP-9, EMERGENT ISSUE RESPONSE, (including Work Week Manager notification). ☐

[1.4] **REVIEW** work schedule and remove work activities on train components. ☐

[1.5] **INITIATE** appropriate actions to restore train components. ☐

[2] **VERIFY** that an Emergency Load Curtailment Plan (ELCP) has been declared and **RECORD** the date and time below. ☐

Date __________ Time __________

[3] **SECURE** all discretionary switching activities and maintenance, that could jeopardize the reliability of either generation or the bulk transmission grid for the duration of the power supply alert/emergency load curtailment. ☐

BFN Unit 0	Grid Instability	0-AOI-57-1E Rev. 0006 Page 6 of 18

4.2 Subsequent Action (continued)

NOTES

1) Changes in reactor power must comply with thermal power limits, rate of change limits and maximum power limits as specified in the unitized GOI-100-12.
2) Fluctuating Frequency and/or Voltages by + 0.15 Hz or + 5kV is indicative of too much generation for the system load. The Generator will have a tendency to pulsate due to coupling and momentum (with speed/frequency rising and lowering).
3) Unless otherwise directed by TVA Transmission System Load Coordinators, **IF** frequency out of range, **THEN**

   PERFORM Step 4.2[5].
4) Unless otherwise directed by TVA Transmission System Load Coordinators, **IF** voltage out of range, **THEN**

   PERFORM Step 4.2[6].

[4] **IF** System Frequency and/or Voltages are continually fluctuating by + 0.15 Hertz or + 5kV, **THEN**

VERIFY/INITIATE Recirc System upper power runback by DEPRESSING 2 (3)-HS-42, UPPER POWER RUNBACK. ☐

[5] **IF** grid instability is characterized by system frequency being maintained outside the normal limits of 60.0 + 0.05 Hz, **THEN**

PERFORM the following:

[5.1] **IF** system frequency is greater than 60.15 Hz, **THEN**

LOWER reactor power by approximately 1%/minute (10 MW(e)/minute) **UNTIL** system frequency returns to 60.03 Hz. ☐

[5.2] **IF** system frequency is lower than 59.85 Hz **AND** reactor power is less than rated power, **THEN**

RAISE reactor power by approximately 1%/minute (10 MW(e)/minute) **UNTIL** system frequency returns to 59.98 Hz. ☐

BFN Unit 0	Grid Instability	0-AOI-57-1E Rev. 0006 Page 7 of 18

4.2 Subsequent Action (continued)

[6] **IF** grid instability is characterized by system voltage being maintained outside the normal limits of 525 + 5 KV, **THEN**

PERFORM the following steps:

[6.1] **IF** system voltage is greater than 540KV, **THEN**

[6.1.1] **LOWER** reactive power to -150 MVAR, **OR UNTIL** system voltage returns to 530KV. □

[6.1.2] **CHECK** 161KV Cap Banks are Out of Service and **EVALUATE** conditions to determine appropriate actions. **REFER TO** 0-GOI-300-4. □

[6.2] **IF** system voltage is lower than 507KV, **THEN**

PERFORM the following:

[6.3] **RAISE** reactive power to +200 MVAR, **OR UNTIL** system voltage returns to 520KV. □

[6.4] **CHECK** 161KV Cap Banks are In Service and **EVALUATE** conditions to determine appropriate actions. **REFER TO** 0-GOI-300-4. □

[7] **MONITOR** system flowrates, operating pump amperages, energized boards and 4KV system voltages. **REFER TO** Attachment 1. □

NOTE
Unit Board 2C and 3C do **NOT** have Tap Changer regulation. Initial rising trend in Pump amps will be indicated on these boards loads first.

[7.1] **IF** the 500 kV System voltage is degraded and Pump amps are rising through the yellow band, **THEN**

PERFORM the following:

[7.1.1] **SECURE** Unit 2(3) CCW Pump 2C(3C). □

[7.1.2] **SECURE** Unit 2(3) Condensate Pump 2C(3C). □

[7.1.3] **SECURE** Unit 2(3) Condensate Booster Pump 2C(3C). □

Examination Outline Cross-reference:	Level	RO	SRO
295009G2.4.18	Tier #		1
Knowledge of specific bases of EOPs. Low Reactor Water Level	Group #		2
	K/A #	295009G2.4.18	
	Importance Rating	3.3	4.0

Proposed Question: **SRO #8**

Given the following Unit 2 conditions:

- Reactor pressure: 10 psig
- Drywell temperature: 250°F
- Secondary Containment temperatures:

74-95F	220°F
74-95C & D	245°F
69-835A thru D	260°F
69-29F, G & H	200°F

- Reactor water level indications:

LI-3-58A & B	Erratic
LI-3-52	(-)140 inches
LI-3-62A	(-)160 inches
LI-3-53, 60 & 206	0 inches
LI-3-55	0 inches

Which ONE of the following describes the required action and the basis for that action?

Enter ________(1)________ due to ____________(2)____________ in the reference legs of LI-3-58A & B.

REFERENCE PROVIDED

	(1)	(2)
A.	2-EOI-C-1, "Alternate Level Control;"	flashing steam
B.	2-EOI-C-4, "RPV Flooding;"	flashing steam
C.	2-EOI-C-1, "Alternate Level Control;"	non-condensible gases coming out of solution
D.	2-EOI-C-4, "RPV Flooding;"	non-condensible gases coming out of solution

Proposed Answer: **B**

Explanation:

a. Flashing steam in the reference legs of LI-3-58A/B is indication of a loss of RPV level instrumentation since Curve 8, RPV Saturation Temp is currently unsafe. However, the correct action is to enter 3-EOI-C4, RPV Flooding. This is plausible because LI-3-52 and 62A are approaching TAF, which would indicate a need to transition to 3-EOI-C1, "Alternate Level Control."

b. Correct answer

c. Noncondensible gases are indicative of "Notching" instruments caused by rapid depressurization. In addition, the incorrect EOI flowchart is entered. This is plausible because LI-3-52 and 62A are approaching TAF, which would indicate a need to transition to 3-EOI-C1, "Alternate Level Control."

d. Non-condensible gases are indicative of "Notching" instruments caused by rapid depressurization. However, the correct EOI flowchart is entered due to a loss of RPV level instrumentation.

Technical Reference(s):	2-EOI-C-4 Flowchart	(Attach if not previously provided)
	EOI Program Manual	

Proposed references to be provided to applicants during examination: EOI Caution 1, Curve 8, Table 6, PIP 95-64

Question Source:	Bank #	X 259002G2.1.23	
	Modified Bank #		(Note changes or attach parent)
	New		
Question History:	Last NRC Exam	3/25/2008	

Question Cognitive Level:	Memory or Fundamental Knowledge	
	Comprehension or Analysis	X

10 CFR Part 55 Content:	55.41	
	55.43	X

Comments:

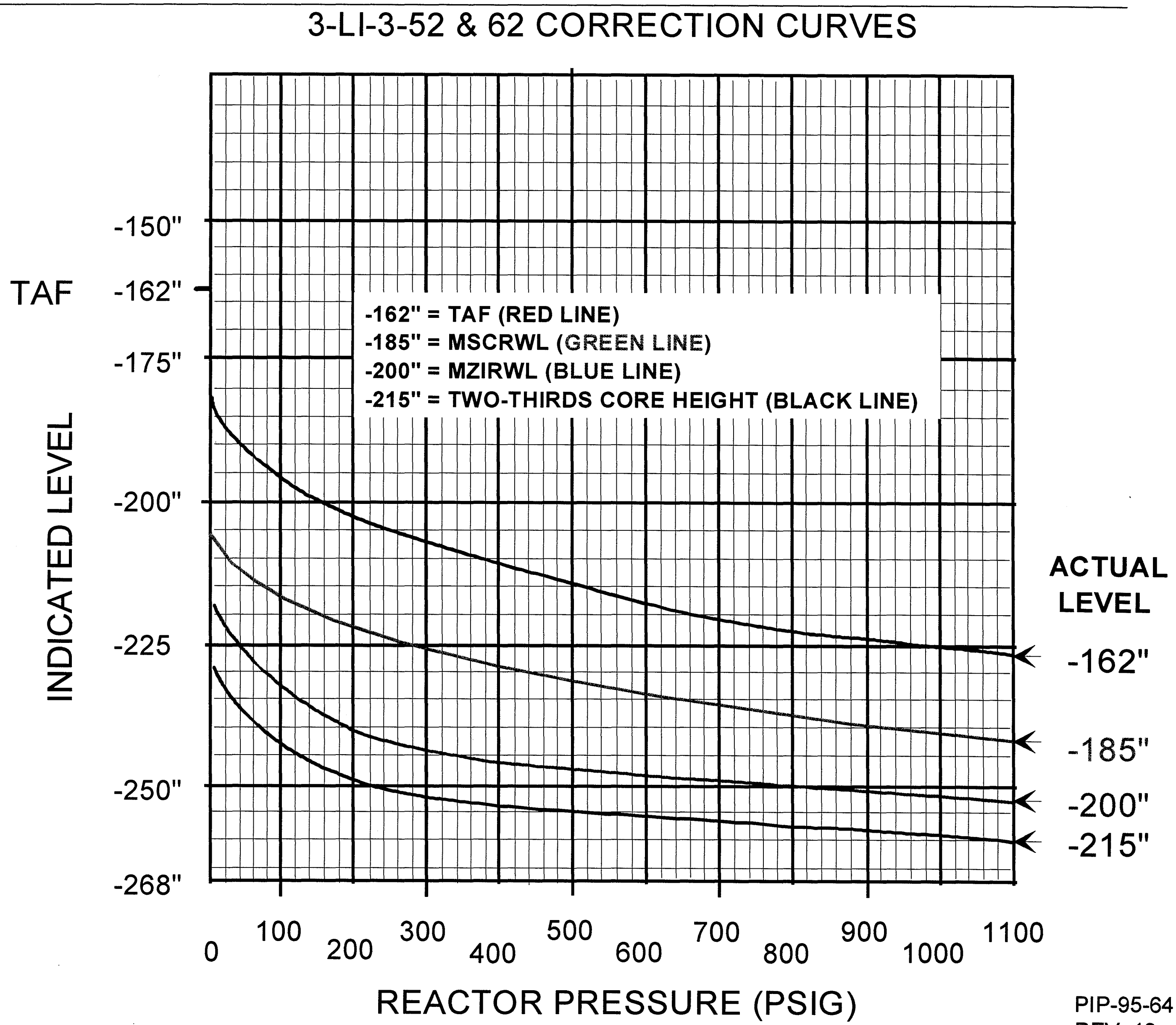
TABLE 6 SECONDARY CONTMT INSTRUMENT RUNS				
INSTRUMENT	SC TEMP ELEMENTS AND LOCATIONS			
	EL 621 (74-95F)	EL 593 (74-95C AND D)	EL 565 (69-835A THRU D)	RWCU HXRM (69-29F, G, H)
LI-3-58A	ºF	ºF	N/A	ºF
LI-3-58B	ºF	ºF	N/A	N/A
LI-3-53	ºF	ºF	N/A	ºF
LI-3-60	ºF	ºF	N/A	N/A
LI-3-206	ºF	ºF	N/A	ºF
LI-3-253	ºF	ºF	N/A	N/A
LI-3-52	ºF	ºF	ºF	N/A
LI-3-62A	ºF	ºF	ºF	N/A
LI-3-55	ºF	ºF	N/A	N/A
LI-3-208A, B	ºF	ºF	N/A	ºF
LI-3-208C, D	ºF	ºF	N/A	N/A

CAUTIONS

CAUTION #1

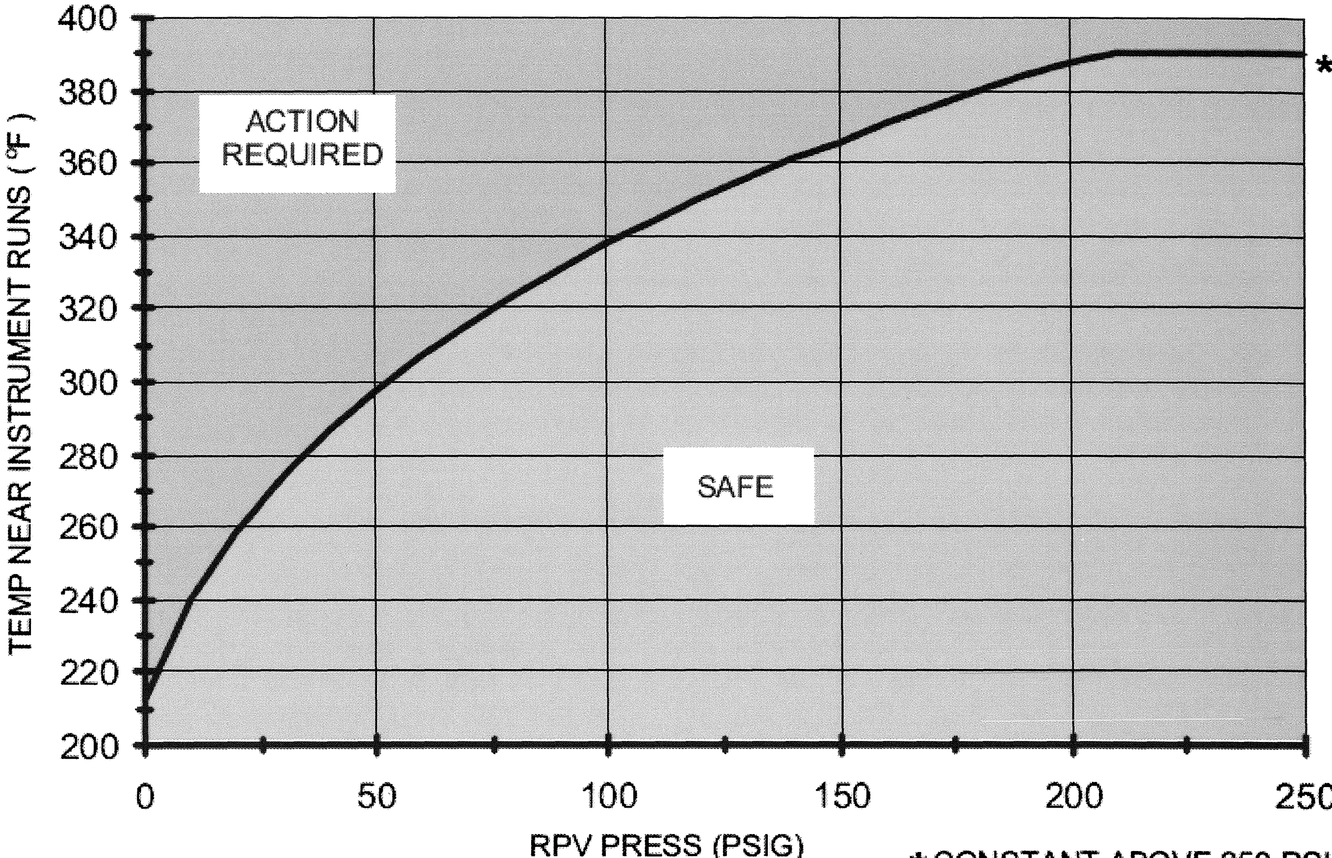
- AN RPV WATER LVL INSTRUMENT MAY BE USED TO DETERMINE OR TREND LVL ONLY WHEN IT READS ABOVE THE MINIMUM INDICATED LVL ASSOCIATED WITH THE HIGHEST MAX DW OR SC RUN TEMP.
- IF DW TEMPS, OR SC AREA TEMPS (TABLE 6), AS APPLICABLE, ARE OUTSIDE THE SAFE REGION OF CURVE 8, THE ASSOCIATED INSTRUMENT MAY BE UNRELIABLE DUE TO BOILING IN THE RUN.

INSTRUMENT	RANGE	MINIMUM INDICATED LVL	MAX DW RUN TEMP (FROM XR-64-50 OR TI-64-52AB)	MAX SC RUN TEMP (FROM TABLE 6)
LI-3-58A, B	EMERGENCY -155 TO +60	ON SCALE	N/A	BELOW 150
		-145	N/A	151 TO 200
		-140	N/A	201 TO 250
		-130	N/A	251 TO 300
		-120	N/A	301 TO 350
LI-3-53 LI-3-60 LI-3-206 LI-3-253 LI-3-208A, B, C, D	NORMAL 0 TO +60	ON SCALE	N/A	BELOW 150
		+5	N/A	151 TO 200
		+15	N/A	201 TO 250
		+20	N/A	251 TO 300
		+30	N/A	301 TO 350
LI-3-52 LI-3-62A	POST ACCIDENT -268 TO +32	ON SCALE	N/A	N/A
LI-3-55	SHUTDOWN FLOODUP 0 TO +400	+10	BELOW 100	N/A
		+15	100 TO 150	N/A
		+20	151 TO 200	N/A
		+30	201 TO 250	N/A
		+40	251 TO 300	N/A
		+50	301 TO 350	N/A
		+65	351 TO 400	N/A



PIP-95-64
REV. 12

CURVE 8
RPV SATURATION TEMP



*CONSTANT ABOVE 250 PSIG

REFERENCE MATERIAL

Provided to

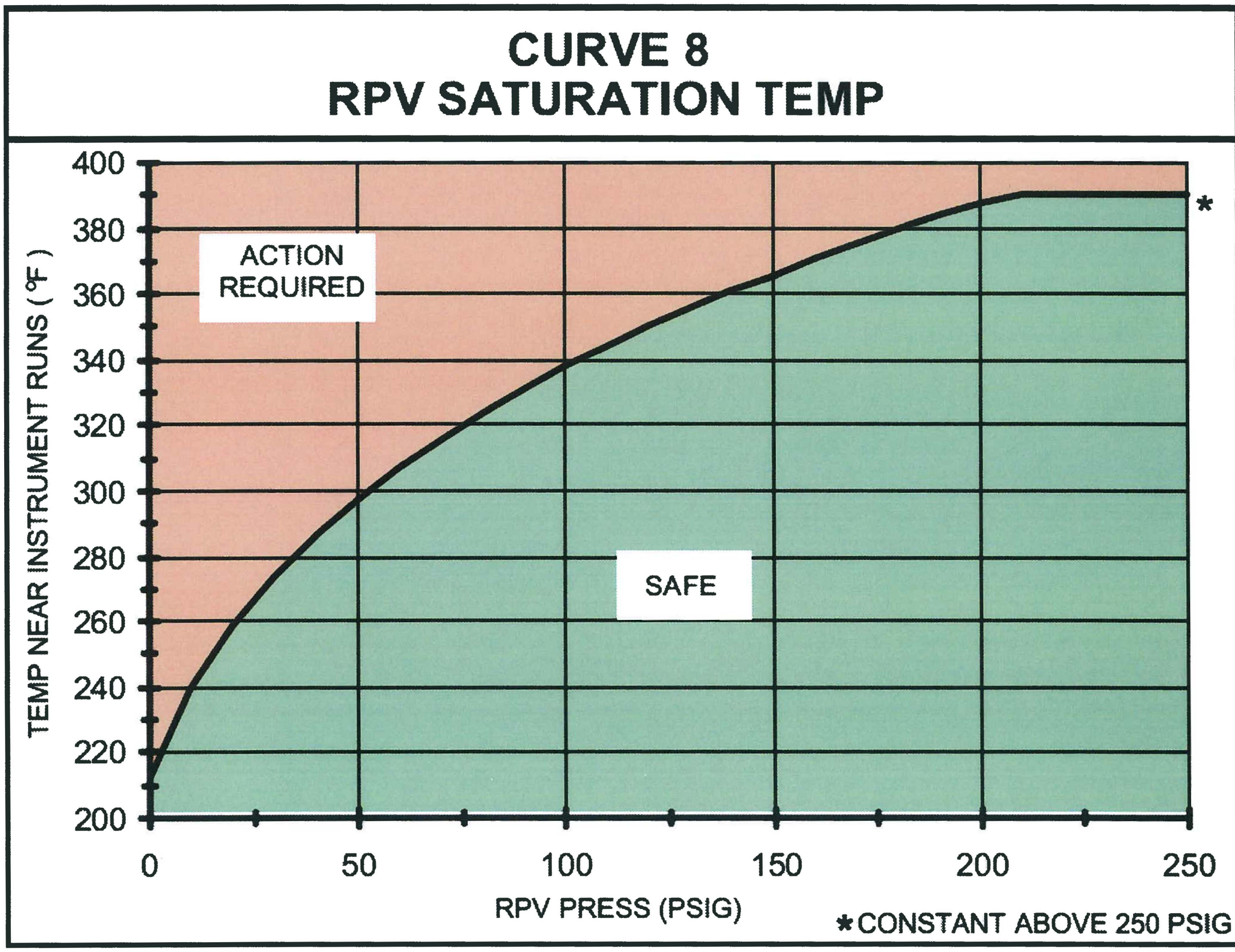
CANDIDATE

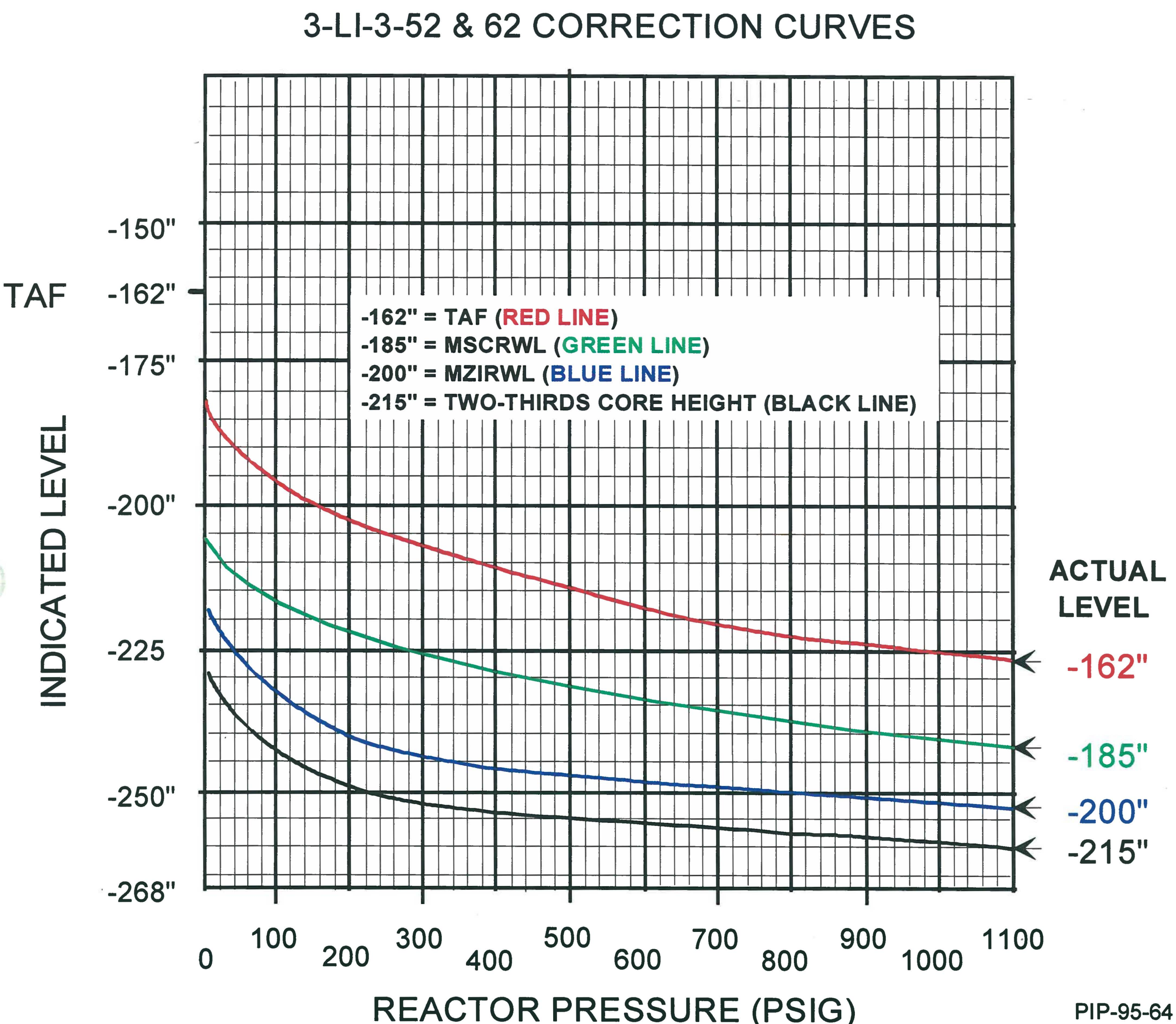
CAUTIONS

CAUTION #1

- AN RPV WATER LVL INSTRUMENT MAY BE USED TO DETERMINE OR TREND LVL ONLY WHEN IT READS ABOVE THE MINIMUM INDICATED LVL ASSOCIATED WITH THE HIGHEST MAX DW OR SC RUN TEMP.
- IF DW TEMPS, OR SC AREA TEMPS (TABLE 6), AS APPLICABLE, ARE OUTSIDE THE SAFE REGION OF CURVE 8, THE ASSOCIATED INSTRUMENT MAY BE UNRELIABLE DUE TO BOILING IN THE RUN.

INSTRUMENT	RANGE	MINIMUM INDICATED LVL	MAX DW RUN TEMP (FROM XR-64-50 OR TI-64-52AB)	MAX SC RUN TEMP (FROM TABLE 6)
LI-3-58A, B	EMERGENCY -155 TO +60	ON SCALE	N/A	BELOW 150
		-145	N/A	151 TO 200
		-140	N/A	201 TO 250
		-130	N/A	251 TO 300
		-120	N/A	301 TO 350
LI-3-53 LI-3-60 LI-3-206 LI-3-253 LI-3-208A, B, C, D	NORMAL 0 TO +60	ON SCALE	N/A	BELOW 150
		+5	N/A	151 TO 200
		+15	N/A	201 TO 250
		+20	N/A	251 TO 300
		+30	N/A	301 TO 350
LI-3-52 LI-3-62A	POST ACCIDENT -268 TO +32	ON SCALE	N/A	N/A
LI-3-55	SHUTDOWN FLOODUP 0 TO +400	+10	BELOW 100	N/A
		+15	100 TO 150	N/A
		+20	151 TO 200	N/A
		+30	201 TO 250	N/A
		+40	251 TO 300	N/A
		+50	301 TO 350	N/A
		+65	351 TO 400	N/A


CURVE 8
RPV SATURATION TEMP
ACTION REQUIRED
SAFE
TEMP NEAR INSTRUMENT RUNS (°F)
400
380
360
340
320
300
280
260
240
220
200
0
50
100
150
200
250
RPV PRESS (PSIG)
*CONSTANT ABOVE 250 PSIG



PIP-95-64
REV. 12

Examination Outline Cross-reference:	Level	RO	SRO
295014AA2.04	Tier #		1
Ability to determine and interpret the following as they apply to Inadvertent Reactivity Addition: Violation of fuel thermal limits.	Group #		2
	K/A #	295014AA2.04	
	Importance Rating	4.1	4.4

Proposed Question: **SRO # 9**

Given the following Unit 2 conditions:

- Reactor power is at 100% rated.
- Unit-2 Cycle 15 exposure is calculated at 30,000 MWd/MTU.
- During performance of 2-SR-3.7.5.1, "Turbine Bypass Valve Cycling", Bypass valve #4 failed to open as required.

Which ONE of the following describes the most limiting Abnormal Operational Transient analyzed in the Final Safety Analysis Report (FSAR) and the most limiting fuel thermal limit during that transient?

The most limiting transient is ______(1)__________ and the most limiting fuel thermal limit associated with that transient is ____(2)_______.

	(1)	(2)
A.	Generator Load Reject	Linear Heat Generation Rate
B.	EHC Pressure Regulator Failure	Linear Heat Generation Rate
C.	Generator Load Reject	Minimum Critical Power Ratio
D.	EHC Pressure Regulator Failure	Minimum Critical Power Ratio

Proposed Answer: **C**

Explanation:

a. Part (1) is correct. Part (2) is incorrect. Although the positive reactivity inserted due to the rapid pressure increase will cause a rapid increase in power, the initiation of a reactor scram will act to turn power quickly near the bottom of the core where the LHGR is most limiting. The area of the core most susceptible to transition boiling is at the top of the core which will remain at a higher power level longer as control rods are inserted.

b. Part (1) is incorrect. An EHC Pressure Regulator failure results in a simultaneous closure of the Main Turbine Control Valves much the same as a load reject. However, the primary difference is the speed at which the TCVs close. A load reject results in a fast closure of the TCVs where an EHC failure closes the TCVs slower. The resultant pressure transient and associated reactivity addition is significant, but less severe.

c. Correct Answer

d. Part (1) is incorrect as stated in (b) above. Part (2) is correct. The area of the core most susceptible to transition boiling is at the top of the core which will remain at a higher power level longer as control rods are inserted. Since Transition Boiling is the failure mechanism of concern with regard to Critical Power Ratio, MCPR is the fuel thermal limit of concern during this transient.

Technical Reference(s): UFSAR Chapter 14.5 Uprated (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/16/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge X

Comprehension or Analysis

10 CFR Part 55 Content: 55.41

55.43 X

Comments: Even though the FSAR categorizes the above transients under "Nuclear System Pressure Increase" and the K/A is asking for "inadvertent reactivity addition", the result of the above transients is more of a concern with reactivity than with pressure. The only other option available involves a loss of feedwater heating which was already covered by a different question on the HLT 0707 SRO exam. To avoid double jeopardy or duplication, I took a small liberty in interpretation of the K/A.

14.5.2.2 Generator Load Reject (TCV Fast Closure) with Turbine Bypass Valve Failure (LRNBP)

14.5.2.2.1 Transient Description

The most severe transient for a full-power generator trip occurs if the turbine bypass valves fail to operate. Although the TCV fast closure time is slightly longer than that of the turbine stop valves, the control valves are considered to be partially closed initially. This results in the generator trip steam supply shutoff being faster than the turbine stop valve steam shutoff.

A generator trip from high power conditions produces a transient sequence similar to the sequence described in Section 14.5.2.1 except the turbine bypass valves are assumed to remain closed. The LRNBP event is caused by the fast closure of all turbine control valves (TCVs) due to significant loss of electrical load on the generator. This will cause a sudden reduction in steam flow that results in significant vessel pressurization. The turbine bypass system is conservatively assumed to be inoperable for this event. A reactor scram signal is initiated by the TCVs closure.

The LRNBP event is identified as one of the most limiting abnormal operational transients for the BFN licensing analyses (assuming all equipment in service). Therefore, this event is analyzed to determine the operating limits and to verify the plant safety margins.

This abnormal operating transient is evaluated for each reload core to determine if this event could potentially alter the previous cycle MCPR operating limit. The analyses of this event for the most recent reload cycle is contained in the unit-specific and cycle-specific Reload Licensing Report.

14.5.2.2.2 Initial Conditions and Assumptions

For GE reload analyses, the analysis described in this section was performed with the ODYN computer code at the limiting power/flow conditions at normal operation: 100 percent rated power (consistent with the current licensing methodology) and maximum core flow (ICF) conditions. For bounding purposes, normal feedwater temperature (as opposed to reduced feedwater temperature) is assumed since the reactor steam generation would be lower with a reduced feedwater temperature. The EOC all-rods-out exposure is assumed to conservatively bound the control rod insertion effectiveness at any other cycle exposure. For FANP reload analyses, the FANP computer codes and analysis methodology described in Section 3.7.7.1.2 "MCPR Operating Limit Calculation Procedure" are used.

BFN-22

14.5.2.2.3 Interpretation of Transient Results

Figure 14.5-5 shows the plant-specific response to the generator load rejection without bypass at 100 percent rated power and 105 percent flow conditions. The neutron flux peaks at 568 percent of initial; the average heat flux peaks at 125 percent of its initial value. The peak pressure at the bottom of the vessel is 1283 psia which is well below the ASME upset code transients limit of 1375 psig while the peak steam line pressure is 1245 psia. The calculated ΔCPR at the stated conditions is 0.19 for GE13 fuel; this result is representative but not bounding for other GE fuel types.

At rated power, the ΔCPR for the LRNBP event is one of the most severe resulting from any other pressurization event. As power is reduced, the severity of the transient increases; but the fuel integrity is protected by the power-flow dependent thermal limits (see Section 14.5.8).

14.5.2.2.4 Generator Load Reject with Turbine Bypass Valve Failure with EOC-RPT-OOS

The EOC-RPT-OOS condition eliminates the automatic Recirculation Pump Trip signal when Load Rejection occurs increasing the severity of the transient response.
At power levels below 30 percent of rated power (P_{bypass}), the RPT is always bypassed in conjunction with the scram on TSVs/TCVs closure. Therefore, these low power cases are not affected by the EOC-RPT-OOS condition.

Figure 14.5-6 shows the transient results for the 100 percent of rated power and 105 percent of rated core flow case. EOC exposure and normal feedwater temperature conditions have been assumed for this transient analysis, the same as in the transient analysis with TBV in service described above.

The neutron flux peaks at 674 percent of initial, the average heat flux peaks at 130 percent of its initial value. The peak pressure at the bottom of the vessel is 1293 psia which is well below the ASME upset code transients limit of 1375 psig while the peak steam line pressure is 1248 psia. The calculated ΔCPR of this transient at the stated conditions is 0.23.

The penalty associated with EOC-RPT-OOS is about 0.04 in ΔCPR. At less than rated core flow, the penalty is smaller because of the relatively reduced beneficial effect of EOC-RPT.

The impact of the EOC-RPT-OOS on the transient fuel protection at off-rated power/flow conditions has been addressed with the appropriate revision to the

Examination Outline Cross-reference:	Level	RO	SRO
295033G2.1.20	Tier #		1
Ability to execute procedure steps. High Secondary Containment Area Radiation Levels.	Group #		2
	K/A #	295033G2.1.20	
	Importance Rating	4.6	4.6

Proposed Question: **SRO #10**

Given the following plant conditions:

- Unit 2 is at 100% rated power.
- A Reactor Water Cleanup (RWCU) drain line cracks and is spilling into the Reactor Building.
- Area Radiation Monitors in the Reactor Building read as follows:

Reactor Building Elevation 593	>1000 mR/hr
Reactor Building Elevation 565 West	800 mR/hr
Reactor Building Elevation 565 East	850 mR/hr
Reactor Building Elevation 565 Northeast	>1000 mR/hr
All other Reactor Building areas	NOT ALARMED

- RWCU Leak Detection Temp High (9-3D W 17) is in alarm.

Which ONE of the following describes the required action that MUST be directed by the Unit Supervisor and/or Shift Manager?

REFERENCE PROVIDED

A. Enter 2-GOI-100-12A, "Unit Shutdown" and commence a normal shutdown / cooldown.

B. Enter 0-EOI-4, "Radioactivity Release Control" and initiate a Reactor Scram.

C. Rapidly depressurize the reactor, to the Main Condenser with the Main Turbine Bypass Valves per 2-EOI-1, "RPV Control."

D. Emergency Depressurize the reactor per 2-EOI-C2, "Emergency RPV Depressurization."

Proposed Answer: **D**

Explanation:

a. This is plausible because this action requires at least one area greater than Max Safe. However, this is not appropriate since the source of the leak is not yet isolated as indicated by the RWCU Leak Detection Temp High annunciator in alarm.

b. This is plausible because this action requires an un-isolable leak and entry into an emergency classification. However, this is not appropriate since the source of the leak is not yet isolated as indicated by the RWCU Leak Detection Temp High annunciator in alarm. Further action to reduce the driving head of the leak is also required.

c. This is plausible because this action requires at least one area greater than Max Safe and another area approaching Max Safe. However, this is not appropriate since the conditions already exist to perform Emergency Depressurization. Rapid depressurization is only performed to avoid conditions that require Emergency Depressurization. It is not a substitute if ED conditions currently exist.

d. correct answer

Technical Reference(s): 2-EOI-3 Flowchart (Attach if not previously provided)

EOI Program Manual

Proposed references to be provided to applicants during examination: 2-EOI-3 Flowchart

Question Source: Bank # 295033EA2.01

Modified Bank # (Note changes or attach parent)

New

Question History: Last NRC Exam 3/25/2008

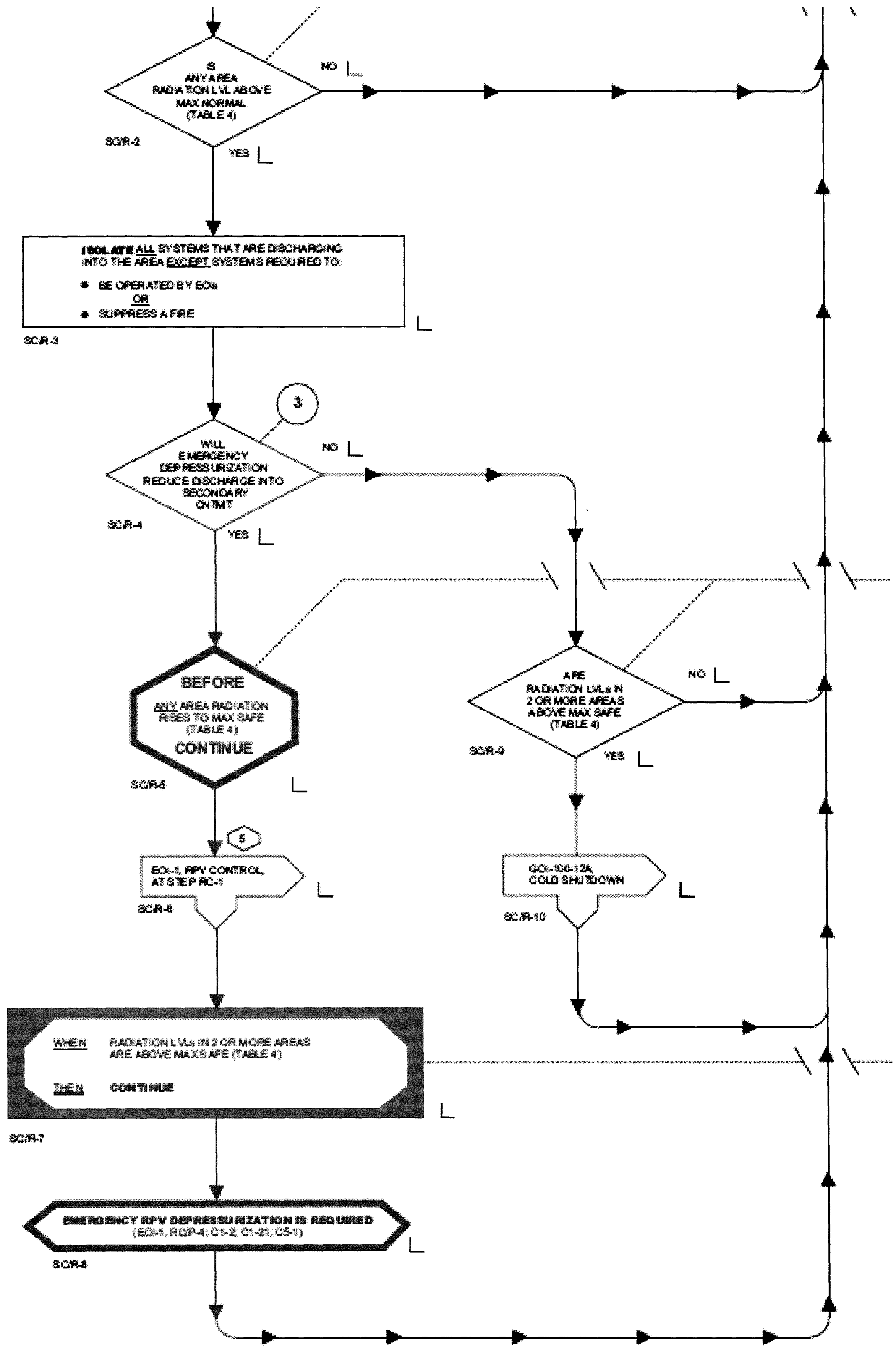
Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments:


IS
ANY AREA
RADIATION LVL ABOVE
MAX NORMAL
(TABLE 4)
NO
YES
SC/R-2
ISOLATE ALL SYSTEMS THAT ARE DISCHARGING
INTO THE AREA EXCEPT SYSTEMS REQUIRED TO:
BE OPERATED BY EOIs
OR
SUPPRESS A FIRE
SC/R-3
3
WILL
EMERGENCY
DEPRESSURIZATION
REDUCE DISCHARGE INTO
SECONDARY
CNTMT
NO
YES
SC/R-4
BEFORE
ANY AREA RADIATION
RISES TO MAX SAFE
(TABLE 4)
CONTINUE
SC/R-5
5
EOI-1, RPV CONTROL,
AT STEP RC-1
SC/R-6
ARE
RADIATION LVLs IN
2 OR MORE AREAS
ABOVE MAX SAFE
(TABLE 4)
NO
YES
SC/R-9
GOI-100-12A,
COLD SHUTDOWN
SC/R-10
WHEN RADIATION LVLs IN 2 OR MORE AREAS
ARE ABOVE MAX SAFE (TABLE 4)
THEN CONTINUE
SC/R-7
EMERGENCY RPV DEPRESSURIZATION IS REQUIRED
(EOI-1, RC/P-4; C1-2; C1-21; C5-1)
SC/R-8

REFERENCE MATERIAL

Provided to

CANDIDATE

EOI-3
UNIT 2

EOI-3

ANY SECONDARY CNTMT AREA TEMP ABOVE MAX NORMAL VALUE OF TABLE 3

SECONDARY CNTMT DP AT OR ABOVE -0.17 IN. OF WATER

RX ZONE VENTILATION EXH RADIATION ABOVE 72 MR/HR

REFUEL ZONE VENTILATION EXH RADIATION ABOVE 72 MR/HR

SECONDARY CNTMT FLOOR DRAIN SUMP WATER LVL ABOVE 66 IN.

ANY SECONDARY CNTMT AREA WATER LVL ABOVE 2 IN.

ANY SECONDARY CNTMT AREA RADIATION LVL ABOVE MAX NORMAL VALUE OF TABLE 4

TABLE 3
SECONDARY CNTMT AREA TEMP

AREA	PANEL 9-3 ALARM WINDOW (UNLESS NOTED)	PANEL 9-21 TEMP ELEMENT (UNLESS NOTED)	MAX NORMAL VALUE °F	MAX SAFE VALUE °F	POTENTIAL ISOLATION SOURCES
RHR SYS I PUMPS	XA-55-3E-4	74-95A	ALARMED	160	FCV-74-47, 48
RHR SYS II PUMPS	XA-55-3E-4	74-95B	ALARMED	210	FCV-74-47, 48
HPCI ROOM	XA-55-3F-10	73-55A	ALARMED	270	FCV-73-2, 3, 44, 81
CS SYS I PUMPS RCIC ROOM	XA-55-3D-10	71-41A	ALARMED	190	FCV-71-2, 3, 39
CS SYS II PUMPS	XA-55-3E-29	75-69B (PANEL 9-3)	ALARMED	150	NONE
TOP OF TORUS	XA-55-3D-10 XA-55-3F-10 XA-55-3E-4	71-41B, C, D 73-55B, C, D 74-95G, H	ALARMED ALARMED ALARMED	200 240 240	FCV-71-2, 3 FCV-73-2, 3, 81 FCV-74-47, 48
STEAM TUNNEL (RB)	XA-55-3D-24	1-60A (PANEL 9-3)	ALARMED	315	MSIVs FCV-71-2, 3, FCV-69-1, 2, 12
DW ACCESS	XA-55-3E-4	74-95E	ALARMED	170	FCV-74-47, 48
RB EL 565 W (RWCU PIPE TRENCH)	XA-55-5B-32 (PANEL 9-5) XA-55-5B-33 (PANEL 9-5)	69-835A, B, C, D (AUX INST ROOM)	ALARMED ALARMED	170	FCV-69-1, 2, 12
RWCU H. X. ROOM	XA-55-3D-17	69-29F, G, H	ALARMED	220	FCV-69-1, 2, 12
RWCU PUMP A	XA-55-3D-17	69-29D	ALARMED	215	FCV-69-1, 2, 12
RWCU PUMP B	XA-55-3D-17	69-29E	ALARMED	215	FCV-69-1, 2, 12
RB EL 593	XA-55-3E-4	74-95C, D	ALARMED	195	FCV-74-47, 48
RB EL 621	XA-55-3E-4	74-95F	ALARMED	156	FCV-43-13, 14

WHILE EXECUTING THIS PROCEDURE:

IF	THEN
SAMG ENTRY IS REQUIRED AND THE TSC SAM TEAM HAS ASSUMED COMMAND AND CONTROL	**EXIT** ALL EOI FLOWCHARTS AND **PERFORM** SAMG ACTIONS AS DIRECTED BY THE SAM TEAM
RX ZONE VENTILATION EXH RADIATION LVL IS ABOVE 72 MR/HR	**VERIFY** ISOLATION OF RX ZONE AND REFUEL ZONE VENTILATION AND **VERIFY** INIT OF SGTS
REFUEL ZONE VENTILATION EXH RADIATION LVL IS ABOVE 72 MR/HR	**VERIFY** ISOLATION OF REFUEL ZONE VENTILATION AND **VERIFY** INIT OF SGTS
RX ZONE VENTILATION IS ISOLATED AND RX ZONE VENTILATION EXH RADIATION LVL IS BELOW 72 MR/HR	**RESTART** RX ZONE VENTILATION (APPX 8F). **DEFEAT** ISOLATION INTERLOCKS IF NECESSARY (APPX 8E)
REFUEL ZONE VENTILATION IS ISOLATED AND REFUEL ZONE VENTILATION EXH RADIATION LVL IS BELOW 72 MR/HR	**RESTART** REFUEL ZONE VENTILATION (APPX 8F). **DEFEAT** ISOLATION INTERLOCKS IF NECESSARY (APPX 8E)

SCC-1

TABLE 4
SECONDARY CNTMT AREA RADIATION

AREA	APPLICABLE RADIATION INDICATORS	MAX NORMAL VALUE MR/HR	MAX SAFE VALUE MR/HR	POTENTIAL ISOLATION SOURCES
RHR SYS I PUMPS	90-28A	ALARMED	1000	FCV-74-47, 48
RHR SYS II PUMPS	90-28A	ALARMED	1000	FCV-74-47, 48
HPCI ROOM	90-24A	ALARMED	1000	FCV-73-2, 3, 44, 81
CS SYS I PUMPS RCIC ROOM	90-26A	ALARMED	1000	FCV-71-2, 3, 39
CS SYS II PUMPS	90-27A	ALARMED	1000	NONE
TOP OF TORUS GENERAL AREA	90-29A	ALARMED	1000	FCV-73-2, 3, 81 FCV-74-47, 48 FCV-71-2, 3
RB EL 565 W	90-20A	ALARMED	1000	FCV-69-1, 2, 12 SDV VENTS & DRAINS
RB EL 565 E	90-21A	ALARMED	1000	SDV VENTS & DRAINS
RB EL 565 NE	90-23A	ALARMED	1000	NONE
TIP ROOM	90-22A	ALARMED	100,000	TIP BALL VALVE
RB EL 593	90-13A, 14A	ALARMED	1000	FCV-74-47, 48
RB EL 621	90-9A	ALARMED	1000	FCV-43-13, 14
RECIRC MG SETS	90-4A	ALARMED	1000	NONE
REFUEL FLOOR	90-1A, 2A, 3A	ALARMED	1000	NONE

IRRESPECTIVE OF THE ENTRY CONDITION, **EXECUTE** SC/T, SC/L, AND SC/R CONCURRENTLY

SCC-2

SC/T

CAUTION
#1 AMBIENT TEMP MAY AFFECT RPV WATER LVL INDICATION AND TREND

MONITOR AND CONTROL SECONDARY CNTMT TEMPs
SC/T-1

OPERATE AVAILABLE VENTILATION (APPX 8F).
DEFEAT ISOLATION INTERLOCKS IF NECESSARY (APPX 8E)
SC/T-2

IS ANY AREA TEMP ABOVE MAX NORMAL (TABLE 3)? NO / YES
SC/T-3

ISOLATE ALL SYSTEMS THAT ARE DISCHARGING INTO THE AREA **EXCEPT** SYSTEMS REQUIRED TO:
- BE OPERATED BY EOIs
OR
- SUPPRESS A FIRE

SC/T-4

(3) WILL EMERGENCY DEPRESSURIZATION REDUCE DISCHARGE INTO SECONDARY CNTMT? NO / YES
SC/T-5

BEFORE ANY AREA TEMP RISES TO MAX SAFE (TABLE 3) **CONTINUE**
SC/T-6

ARE TEMPs IN 2 OR MORE AREAS ABOVE MAX SAFE (TABLE 3)? NO / YES
SC/T-10

(6) EOI-1, RPV CONTROL AT STEP RC-1
SC/T-7

GOI-100-12A, COLD SHUTDOWN
SC/T-11

WHEN TEMPs IN 2 OR MORE AREAS ARE ABOVE MAX SAFE (TABLE 3)
THEN CONTINUE
SC/T-8

EMERGENCY RPV DEPRESSURIZATION IS REQUIRED (EOI-1, RC/P-4; C1; C2; C4)
SC/T-9

SC/L

MONITOR AND CONTROL SECONDARY CNTMT WATER LVLs
SC/L-1

EXECUTE SC/L-3 AND SC/L-6 CONCURRENTLY
SC/L-2

IS ANY FLOOR DRAIN SUMP WATER LVL ABOVE 66 IN.? NO / YES
SC/L-3

RESTORE AND MAINTAIN FLOOR DRAIN SUMP WATER LVLs BELOW 66 IN. USING ALL AVAILABLE SUMP PUMPS
SC/L-4

CAN ALL FLOOR DRAIN SUMP WATER LVLs BE RESTORED AND MAINTAINED BELOW 66 IN.? NO / YES
SC/L-5

IS ANY AREA WATER LVL ABOVE 2 IN.? NO / YES
SC/L-6

RESTORE AND MAINTAIN AREA WATER LVLs BELOW 2 IN. USING ALL AVAILABLE SUMP PUMPS
SC/L-7

CAN ALL AREA WATER LVLs BE RESTORED AND MAINTAINED BELOW 2 IN.? NO / YES
SC/L-8

ISOLATE ALL SYSTEMS THAT ARE DISCHARGING INTO THE AREA **EXCEPT** SYSTEMS REQUIRED TO:
- BE OPERATED BY EOIs
OR
- SUPPRESS A FIRE

SC/L-9

(3) WILL EMERGENCY DEPRESSURIZATION REDUCE DISCHARGE INTO SECONDARY CNTMT? NO / YES
SC/L-10

BEFORE ANY AREA WATER LVL RISES TO 20 IN. **CONTINUE**
SC/L-11

ARE WATER LVLs IN 2 OR MORE AREAS ABOVE 20 IN.? NO / YES
SC/L-15

(11) EOI-1, RPV CONTROL AT STEP RC-1
SC/L-12

GOI-100-12A, COLD SHUTDOWN
SC/L-16

WHEN WATER LVLs IN 2 OR MORE AREAS ARE ABOVE 20 IN.
THEN CONTINUE
SC/L-13

EMERGENCY RPV DEPRESSURIZATION IS REQUIRED (EOI-1, RC/P-4; C1; C2; C4)
SC/L-14

SC/R

MONITOR AND CONTROL SECONDARY CNTMT RADIATION LVLs
SC/R-1

IS ANY AREA RADIATION LVL ABOVE MAX NORMAL (TABLE 4)? NO / YES
SC/R-2

ISOLATE ALL SYSTEMS THAT ARE DISCHARGING INTO THE AREA **EXCEPT** SYSTEMS REQUIRED TO:
- BE OPERATED BY EOIs
OR
- SUPPRESS A FIRE

SC/R-3

(3) WILL EMERGENCY DEPRESSURIZATION REDUCE DISCHARGE INTO SECONDARY CNTMT? NO / YES
SC/R-4

BEFORE ANY AREA RADIATION LVL RISES TO MAX SAFE (TABLE 4) **CONTINUE**
SC/R-5

ARE RADIATION LVLs IN 2 OR MORE AREAS ABOVE MAX SAFE (TABLE 4)? NO / YES
SC/R-9

(6) EOI-1, RPV CONTROL AT STEP RC-1
SC/R-6

GOI-100-12A, COLD SHUTDOWN
SC/R-10

WHEN RADIATION LVLs IN 2 OR MORE AREAS ARE ABOVE MAX SAFE (TABLE 4)
THEN CONTINUE
SC/R-7

EMERGENCY RPV DEPRESSURIZATION IS REQUIRED (EOI-1, RC/P-4; C1; C2; C4)
SC/R-8

CAUTIONS

CAUTION #1

- ANY RPV WATER LVL INSTRUMENT MAY BE USED TO DETERMINE OR TREND LVL ONLY WHEN IT READS ABOVE THE MINIMUM INDICATED LVL ASSOCIATED WITH THE HIGHEST MAX DW OR SC RUN TEMP.
- IF DW TEMPS, OR SC AREA TEMPS (TABLE 6) AS APPLICABLE, ARE OUTSIDE THE SAFE REGION OF CURVE 8, THE ASSOCIATED INSTRUMENT MAY BE UNRELIABLE DUE TO BOILING IN THE RUN.

INSTRUMENT	RANGE	MINIMUM INDICATED LVL	MAX DW RUN TEMP (FROM XR-64-50 OR TI-64-52AB)	MAX SC RUN TEMP (FROM TABLE 6)
LI-3-58A, B	EMERGENCY -155 TO +60	ON SCALE	N/A	BELOW 150
		-145	N/A	151 TO 200
		-140	N/A	201 TO 250
		-130	N/A	251 TO 300
		-120	N/A	301 TO 350
LI-3-53 LI-3-60 LI-3-206 LI-3-253 LI-3-208A, B, C, D	NORMAL 0 TO +60	ON SCALE	N/A	BELOW 150
		+5	N/A	151 TO 200
		+10	N/A	201 TO 250
		+20	N/A	251 TO 300
		+30	N/A	301 TO 350
LI-3-52 LI-3-62A	POST ACCIDENT -268 TO +32	ON SCALE	N/A	N/A
LI-3-55	SHUTDOWN FLOODUP 0 TO +400	+15	BELOW 100	N/A
		+15	100 TO 150	N/A
		+20	151 TO 200	N/A
		+30	201 TO 250	N/A
		+40	251 TO 300	N/A
		+50	301 TO 350	N/A
		+55	351 TO 400	N/A

CURVE 8
RPV SATURATION TEMP

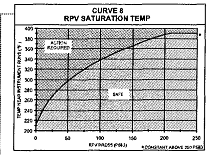


TABLE 6
SECONDARY CNTMT INSTRUMENT RUNS

INSTRUMENT	EL 621 (74-95F)	EL 593 (74-95C AND D)	EL 565 (69-835A THRU D)	RWCU HX RM (69-29F, G, H)
LI-3-58A	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-58B	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-53	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-60	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-206	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-253	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-52	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-62A	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-55	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-208A, B	[illegible]	[illegible]	[illegible]	[illegible]
LI-3-208C, D	[illegible]	[illegible]	[illegible]	[illegible]

NOTES

(3) TABLES 3 AND 4 CONTAIN INFORMATION THAT MAY BE USED TO DETERMINE IF A PRIMARY SYSTEM IS DISCHARGING INTO SECONDARY CNTMT (EMERGENCY DEPRESSURIZATION WILL REDUCE DISCHARGE)

2-EOI-3	PAGE 1 OF 1
SECONDARY CONTAINMENT CONTROL	
UNIT 2 BROWNS FERRY NUCLEAR PLANT	
REV: 11	

EOI-3

Examination Outline Cross-reference:	Level	RO	SRO
203000G2.4.40	Tier #		2
Ability to apply Technical Specifications for RHR/LPCI Injection Mode.	Group #		1
	K/A #	203000G2.4.40	
	Importance Rating	3.4	4.7

Proposed Question: **SRO #11**

Unit 2 is being shutdown because the RHR Loop II has been inoperable for 6 days.

- RHR Loop II is tagged out for maintenance on the outboard injection valve.
- A cooldown is in progress.
- Reactor pressure is currently at 150 psig.

In addition to an OPERABLE injection flowpath, which ONE of the following describes the minimum required RHR pumps for an OPERABLE Low Pressure ECCS subsystem, and can RHR Loop I be flushed in preparation for shutdown cooling under this condition?

An OPERABLE Low Pressure ECCS subsystem requires __(1)__. In order to comply with Technical Specifications, flushing RHR Loop I ___(2)___ allowable.

	(1)	(2)
A.	one RHR pump	is
B.	one RHR pump	is NOT
C.	two RHR pumps	is
D.	two RHR pumps	is NOT

Proposed Answer: **D**

Explanation:

a. Tech Spec bases require 2 RHR pumps per subsystem while in mode 3. Core Spray only requires one pump per subsystem. In addition, flushing RHR requires defeating valve interlocks which would make LPCI Loop I INOPERABLE during the flush. Although Tech Spec SR 3.5.1.2 allows RHR to be lined up for Shutdown Cooling, this does not include the prerequisite flushing evolution.

b. Part (1) incorrect as in (a) above. Part (2) is correct.

c. Part (1) is correct. Part (2) is incorrect as in (a) above.

d. correct answer

Technical Reference(s): U2 TSR section 3.5.1, 2-OI-74 (Attach if not previously provided)

U2 TSB section 3.5.1

Proposed references to be provided to applicants during examination: None

Question Source: Bank # X OPL171-044 #120

Modified Bank # (Note changes or attach parent)

New

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

BASES

BACKGROUND (continued)

at 0.2 seconds when offsite power is available and B, C, and D pumps approximately 7, 14, and 21 seconds afterwards and if offsite power is not available all pumps 7 seconds after diesel generator power is available). When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the CS System without spraying water in the RPV.

LPCI is an independent operating mode of the RHR System. There are two LPCI subsystems (Ref. 2), each consisting of two motor driven pumps and piping and valves to transfer water from the suppression pool to the RPV via the corresponding recirculation loop.

The two LPCI pumps and associated motor operated valves in each LPCI subsystem are powered from separate 4 kV shutdown boards. Both pumps in a LPCI subsystem inject water into the reactor vessel through a common inboard injection valve and depend on the closure of the recirculation pump discharge valve following a LPCI injection signal. Therefore, each LPCI subsystem's common inboard injection valve and recirculation pump discharge valve are powered from one of the two 4 kV shutdown boards associated with that subsystem. The ability to provide power to the inboard injection valve and the recirculation pump discharge valve from two independent 4 kV shutdown boards ensures that a single failure of a diesel generator (DG) will not result in the failure of both LPCI pumps in one subsystem.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify, for each ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	31 days
SR 3.5.1.2	-----------------------NOTE----------------------- Low pressure coolant injection (LPCI) subsystems may be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the Residual Heat Removal (RHR) low pressure permissive pressure in MODE 3, if capable of being manually realigned and not otherwise inoperable. ---	
	Verify each ECCS injection/spray subsystem 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.	31 days
SR 3.5.1.3	Verify ADS air supply header pressure is ≥ 81 psig.	31 days
SR 3.5.1.4	Verify the LPCI cross tie valve is closed and power is removed from the valve operator.	31 days

(continued)

BFN Unit 2	Residual Heat Removal System	2-OI-74 Rev. 0133 Page 88 of 367

8.7 Loop I(II) Flush for Shutdown Cooling

CAUTION

In order to ensure adequate net positive suction head (NPSH) on the CRD pumps, the level in any CST should not be allowed to drop below 15 feet, as indicated by the Condensate Storage Tank Level indicators on Unit 1 Panel 9-20.

NOTES

1) All operations are performed at Panel 2-9-3 unless otherwise noted.
2) A WO is used to place and subsequently remove temporary jumpers between terminal points 84 and 85 on Loop I (terminal points 84 and 85, Loop II) in the limit switch compartments of 2-FCV-74-2 and 2-FCV-74-13, Loop I (2-FCV-74-25 and 2-FCV-74-36, Loop II) to bypass interlock with 2-FCV-74-57, Loop I (2-FCV-74-71, Loop II).

[1] **IF** CS&S has been aligned as the keep fill source for two days or more, **THEN**

[1.1] **REQUEST** chemistry to sample. ☐

[1.2] **IF** water quality requirements are met, **THEN**

PROCEED TO Section 8.8. ☐

[1.3] **IF** water quality requirements are not met, **THEN**

CONTINUE in this section. ☐

[2] **VERIFY** the following initial conditions are satisfied:

[2.1] RHR Loop I(II) is in Standby Readiness. **REFER TO** Section 4.0. REFER TO Tech Specs for RHR operability requirements. ☐

[2.2] Condensate Transfer System in service to provide RHR flush water. REFER TO 0-OI-2B. ☐

Examination Outline Cross-reference:	Level	RO	SRO
215003G2.1.28	Tier #		2
Knowledge of the purpose and function of major system components and controls: IRM	Group #		1
	K/A #	215003G2.1.28	
	Importance Rating	4.1	4.1

Proposed Question: **SRO #12**

Given the following plant conditions:

- Unit 3 is performing a startup and heatup in accordance with 3-GOI-100-1A, "UNIT STARTUP."
- IRM 'B' is in BYPASS.
- No IRM Range Switches are being manipulated.
- All OPERABLE IRMs are on Range 7 when a half-scram occurs on RPS 'A'.
- The Reactivity Manager reports the cause of the half-scram was due to a momentary Upscale Trip on IRM 'G;' but, the IRM is currently reading normally.

Whose approval, if any, is required in accordance with 3-GOI-100-1A to bypass IRM 'G', and what are the required actions per Technical Specifications, if any?

A. Plant Manager or designee approval is required.
NO Tech Spec action is required.

B. Plant Manager or designee approval is required.
Place ONE IRM channel in the TRIP condition.

C. NO approvals are required.
NO Tech Spec action is required.

D. NO approvals are required.
Place ONE IRM channel in the TRIP condition.

Proposed Answer: **C**

Explanation:

a. Part (1) is incorrect. Plant Manager's permission is NOT required since the bypass is directed by an approved procedure. Part (2) is correct.

b. Part (1) is incorrect. Plant Manager's permission is NOT required since the bypass is directed by an approved procedure. Part (2) is incorrect. Tech Spec 3.3.1.1 requires 3 OPERABLE channels per trip system. IRM 'G' is not required to be OPERABLE since all other IRMs assigned to trip system "A" are OPERABLE.

c. Correct answer.

d. Part (1) is correct. Part (2) is incorrect. Tech Spec 3.3.1.1 requires 3 OPERABLE channels per trip system. IRM 'G' is not required to be OPERABLE since all other IRMs assigned to trip system "A" are OPERABLE.

Technical Reference(s):	3-OI-92A, 3-ARP-9-5A (33)	(Attach if not previously provided)
	U3 TSR 3.3.1.1	

Proposed references to be provided to applicants during examination: None

Question Source:	Bank #	215003G2.1.14	
	Modified Bank #		(Note changes or attach parent)
	New		
Question History:	Last NRC Exam		

Question Cognitive Level:	Memory or Fundamental Knowledge	
	Comprehension or Analysis	X

10 CFR Part 55 Content:	55.41	
	55.43	X

Comments:

BFN Unit 3	Panel 9-5 3-XA-55-5A	3-ARP-9-5A Rev. 0037 Page 43 of 45

IRM
CH A, C, E, G
HI-HI/INOP

RED BAR 33

(Page 1 of 1)

Sensor/Trip Point:

Relay K-16

A. HI-HI ≥ 116.4 on 125 scale
B. INOP.
   1. Hi voltage low.
   2. Module unplugged.
   3. Function switch **NOT** in OPERATE.
   4. Loss of ± 24 VDC to monitor

Sensor Location: Control Room Panel 3-9-12.

Probable Cause:

A. Flux level at or above setpoint.
B. One or more inoperable conditions exist.
C. SI or SR in progress.
D. Malfunction of sensor.
E. Control rod drop accident.

Automatic Action:

A. Half-scram if one sensor actuates (except with Rx Mode Sw. in RUN).
B. Reactor scram if one sensor per channel actuates, (except with Rx Mode Sw. in RUN).

Operator Action:

A. **STOP** any reactivity changes. ☐
B. **VERIFY** alarm by multiple indications. ☐
C. **RANGE** initiating channel or **BYPASS** initiating channel. REFER TO 3-OI-92A. ☐
D. With SRO permission, **RESET** Half Scram. **REFER TO** 3-OI-99
E. **IF** alarm is from a control rod drop, **THEN** **REFER TO** 3-AOI-85-1. ☐
F. [NRC/C] **IF** one or more IRM recorder reading is downscale, **THEN** **CHECK** for loss of ± 24 VDC power. ☐
G. **NOTIFY** Instrument Maintenance that functional tests of any monitors indicating an INOP condition, including a downscale reading, are required before the instrument can be considered operable. [NRC IE item 86-40-03] ☐
H. **NOTIFY** Reactor Engineer. ☐
I. **REFER TO** Tech Spec Table 3.3.1.1-1, TRM Tables 3.3.4-1 and 3.3.5-1. ☐

References:

3-45E620-6	197R114-16 GEK	3-730E915-10
3-730E915RF-12	3-OI-92A	3-AOI-85-1
Technical Specifications	Technical Requirements Manual-TRM	

BFN Unit 3	Unit Startup	3-GOI-100-1A Rev. 0071 Page 18 of 165

3.2 Coolant and Metal Temperatures (continued)

3. During Reactor heatup, operators should use metal temperatures as a reminder that as metal heats up, the moderator HEATUP RATE will rise with the same amount of heat input.

D. Minimizing operation with low feedwater flow and temperature or cold feedwater flow cycling limits thermal duty on feedwater nozzles (REFER TO 3-OI-3).

3.3 Primary Containment

A. [II/F] Prior to initiating any event which adds, or has the potential to add, heat energy to the suppression chamber, the Unit Supervisor or Shift Manager will evaluate the necessity of placing suppression pool cooling in service. This is due to the potential of developing thermal stagnation during sustained heat additions. [II-B-91-129]

B. When containment integrity is required, airlock door seals should be tested within seven days after each containment access per 0-TI-360 App A.

3.4 Control Rods, Reactivity Control and Relative Instrumentation

A. [NRC/C] Startups are performed using 3-SR-3.1.3.5(A) to incorporate Reduced Notch Worth Procedure (RNWP) and Banked Position Withdrawal Sequence (BPWS) recommended by G.E. [IE Bulletin 79-12, LER 260/84004]

B. [NER/C] Periodic pauses during control rod withdrawal are necessary to allow for stabilization of neutron level and collection of data for estimating proximity to critically. [SER 89-006, SOER 88-002]

C. [INPO/C] Adjustment of Nuclear Instrumentation readings downward to match other indications without a full investigation and comparison with all available methods to measure power level may result in non-conservative power readings and protective setpoints. [SOER 90-003, SOER-88-002]

D. [NER/C] If SRMs or IRMs exhibit noise spikes during startup, control rod withdrawal should be suspended and an assessment of SRM or IRM operability performed in accordance with 3-OI-92 or 3-OI-92A, as applicable. [SOER 88-002]

E. [NER/C] Activities that can directly affect core reactivity are of a critical nature and require strict procedural compliance, along with conservative actions. [INPO SER 89-006, SOER 88-002]

F. [NSRB/C] Reactivity can be added without moving control rods due to changing plant conditions (such as lowering moderator temperature, lowering xenon concentration, rising Reactor pressure, and rising feedwater flow) especially at low power. Awareness of these conditions and monitoring core instrumentation for these changes is required. [A258-4]

BFN Unit 3	Intermediate Range Monitors	3-OI-92A Rev. 0014 Page 8 of 15

3.0 PRECAUTIONS AND LIMITATIONS (continued)

L. [II/F] An IRM or SRM may be bypassed in the following conditions:

1. STOP control rod withdrawal and PLACE the channel in bypass when the SRM or IRM first gets noisy.

2. STOP control rod withdrawal and PLACE the channel in bypass immediately upon receipt of a single event large noise spike.

These conditions bypass the instrument for an operability assessment based on whether the noise is transitory or sustained. Transitory noise is considered a one time occurrence that does not repeat itself and the channel can be removed from bypass and restored to service.

Sustained noise is when the duration exceeds 15 minutes and may result in signal build up until a trip signal is reached. If a trip or high flux signal was generated, the channel is required to be observed for at least 15 minutes before returning the instrument to service with concurrence from System Engineering.

When the initial assessment and recognition of the magnitude of the event has been determined, then control rod withdrawal may be resumed where it has been left off as long as the minimum number of SRM and IRM channels operable are within the Technical Specification limits. [II-B-91-040]

M. [QA/C] SPP-10.4 requires approval of the Plant Manager or his designee prior to any planned operation with IRMs bypassed unless bypassing is specifically allowed within approved procedures. [SE-NPS-92-R01]

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required channels inoperable.	A.1	Place channel in trip.	12 hours
	OR		
	A.2	------------NOTE------------ Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. ----------------------------- Place associated trip system in trip.	12 hours

(continued)

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux - High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 120/125 divisions of full scale
	5[(a)]	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.9 SR 3.3.1.1.14	≤ 120/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.14	NA
	5[(a)]	3	H	SR 3.3.1.1.4 SR 3.3.1.1.14	NA
2. Average Power Range Monitors					
a. Neutron Flux - High, (Setdown)	2	3[(b)]	G	SR 3.3.1.1.1 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 15% RTP
b. Flow Biased Simulated Thermal Power - High	1	3[(b)]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 0.66 W + 66% RTP and ≤ 120% RTP[(c)]
c. Neutron Flux - High	1	3[(b)]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.16	≤ 120% RTP

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) Each APRM channel provides inputs to both trip systems.

(c) [.66 W + 66% - .66 Δ W] RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

Examination Outline Cross-reference:	Level	RO	SRO
215005A2.06	Tier #		2
Ability to (a) predict the impacts of the following on the APRM/LPRM system and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal conditions or operations: Recirculation Flow Channels Upscale	Group #		1
	K/A #	215005A2.06	
	Importance Rating	3.4	3.5

Proposed Question: **SRO #13**

Given the following plant conditions:

- Unit-2 is operating at 100% rated power
- Control Rod Withdrawal Block (9-5A W7) in alarm.
- APRM Flow Bias Off Normal (9-5A W32) in alarm.
- 2A Recirc Pump Flow indicator 2-FI-68-5 indicates upscale in Panel 9-4.

Which ONE of the following describes the required action to clear the above alarm conditions and the final status of 2-FI-68-5 once the above action is accomplished?

Direct ______(1)______. Flow indicator 2-FI-68-5 will be reading ____(2)____.

	(1)	(2)
A.	APRM #3 bypassed per 2-OI-92B, "Average Power Range Monitoring."	normally
B.	APRM #3 bypassed per 2-OI-92B, "Average Power Range Monitoring."	upscale
C.	RBM "A" bypassed per 2-OI-92C, "Rod Block Monitor."	normally
D.	RBM "A" bypassed per 2-OI-92C, "Rod Block Monitor."	upscale

Proposed Answer: **B**

Explanation:

a. Bypassing the APRM is correct, however that will not effect the flow indication on panel 9-4. This indicator will continue to read upscale until repaired.

b. correct answer

c. Bypassing the RBM will clear the rod block but not the flow bias off normal condition. #2 incorrect as stated in (a) above.

d. Bypassing the RBM will clear the rod block but not the flow bias off normal condition. #2 is correct.

Technical Reference(s): 2-OI-92B, 2-OI-92C (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New X 6/22/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge X

Comprehension or Analysis

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

BFN Unit 2	Panel 9-5 2-XA-55-5A	2-ARP-9-5A Rev. 0042 Page 11 of 45

CONTROL ROD WITHDRAWAL BLOCK

YELLOW BAR 7

(Page 1 of 2)

Sensor/Trip Point:

Relays:	3A-K1	Nuclear Instrumentation
	3A-K2	Refuel Equipment In Use
		High Level In Scram Discharge Volume
		Scram Discharge Volume High Water Level Bypass
		Rx Mode Switch in Shutdown
		PRNM (ANY APRM, OPRM or RBM)

Sensor Location: Panel 2-9-28
Elevation 593'
Aux Instr Room

Probable Cause:
A. One or more sensors at or above set point.
B. Malfunction of sensor.
C. Control rod drop accident.

Automatic Action: Rod withdrawal block.

Operator Action:

A. **DETERMINE** initiating condition from corresponding rod withdrawal block alarm(s) and **REFER TO** operator action for alarm(s). ☐

B. **IF** alarm due to inadvertent criticality during incore fuel movements, **THEN**
REFER TO 2-AOI-79-2. ☐

C. **IF** alarm is from a control rod drop, **THEN**
REFER TO 2-AOI-85-1. ☐

D. **IF** NO corresponding alarm exists, **THEN** ☐
1. AT ICS console, **DETERMINE** if there is a refuel rod block by selecting Single Point Menu, Single Value Display, and typing F602, RETURN. ☐
2. **IF** rod block was from Refuel Floor, **THEN**
NOTIFY Refuel Floor Operator to have dummy plug (Refuel floor between cavity and pool, southside) checked. ☐
3. **WHEN** IRM switches are below Range 3 with REACTOR MODE SWITCH not in RUN, **THEN**
CHECK SRM detectors NOT FULL IN. ☐
4. **WHEN** REACTOR MODE SWITCH is in START-UP position, **THEN**
CHECK IRM detectors NOT FULL IN. ☐

E. **REFER TO** Tech Spec Table 3.3.2.1-1, TRM Table 3.3.4-1. ☐

Continued on Next Page

BFN Unit 2	Panel 9-5 2-XA-55-5A	2-ARP-9-5A Rev. 0042 Page 42 of 45

APRM FLOW BIAS OFF NORMAL
YELLOW BAR 32

(Page 1 of 1)

Sensor/Trip Point:

APRM Channel 1,2,3,4 FLOW ≥ 107% or failed. — (1) Either APRM Channel Recirc Flow ≥ 107% or has failed upscale.

Sensor Location: 2/4 Logic Modules (Voters) located in Panel 2-9-14, Main Control Room.

Probable Cause:
A. Malfunction of flow circuit instrumentation.
B. Testing in progress.
C. Malfunction of Sensor.

Automatic Action: Rod block.
FLOW signal on APRM bargraph indicates either > 107% or Failed upscale as seen by "↑↑↑" on the Display screen.

Operator Action:
A. **VERIFY** Rod Block. ☐
B. **REQUEST** IMs to check for high output or mismatch. ☐
C. **VERIFY** flow by either the > 107% FLOW or "↑↑↑" indicated on the APRM Display. ☐
D. **REFER TO** Tech. Spec Table 3.3.1.1-1 TRM Table 3.3.4-1, Sect. 5.3.1. ☐

References: 2-45E620-6. GEK 103936
Technical Specifications Technical Requirements Manual-TRM

k. **Recirculation Flow Monitor** — Obj V.B.9, V.D.5 V.B.11

(1) Each flow monitor channel consists of two flow inputs used to calculate a Total Recirculation Flow, one from Recirculation Loop A and one from Recirculation Loop B.

(2) Each APRM receives the inputs from two (4 to 20 ma) differential pressure (ΔP) transmitters used to measure the recirculation loop flows. — Displayed on Input Status display

(3) When the ma current is less than 4.0 ma, the recirculation flow value is set to zero (0.0%).

(4) The loop flow continues to be calculated when the ma current is above 20.0 ma (i.e., the value is not clamped at 125.0% flow).

(5) The flow monitor is considered INOP whenever loop current is less than 1.0 ma or greater than 25.0 ma. — Inputs to flow upscale alarm APRM flow alarm is when flow is >107 % or upscale, generates rod block

(6) Each RBM receives the four Total Recirculation Flow values from the APRM channels to determine the status of the flow compare alarm.

(7) The Recirculation Flow Monitor Function provides the following alarm functions for each Total Recirculation Flow level:

- **FLOW UPSCALE ALARM (generated by the APRM)**
- **FLOW COMPARE ALARM (generated by the RBM).**

(8) The table below shows the relationship between the flow monitors and each APRM channel.

Attention to Detail
Right unit/train/comp

Discuss effects if flow transmitters fail

	Loop A	Loop B
APRM 1	FT-68-5A	FT-68-81A
APRM 2	FT-68-5B	FT-68-81B
APRM 3	FT-68-5C	FT-68-81C
APRM 4	FT-68-5D	FT-68-81D

Flow indicators (9-4)
Flow Recorder (9-4)
V.B.10 V.C.3

(9) Since the APRM (channels 3 and 4) are used to generate the analog signal output to the flow indicators and recorders on panel 9-4, a loss of power, or if the APRM chassis is unplugged would interrupt the flow signals for panel 9-4 indications.

(10) The APRM converts the 4 to 20 ma input signals, from the transmitters, to digital signals.

(11) Each APRM calculates a Total Recirculation Flow value:

V.B.11
APRM

(a) by averaging its assigned loop A and loop B recirculation flow values.

OPRM

(b) Each APRM uses its Total Recirculation Flow value for **its flow biased trips and alarms**.

(c) In addition, Total Recric Flow is also used for **enabling OPRM trips and alarms**.

(12) The Total Recirculation Flow signal for each APRM channel is continually processed even when the APRM channel is bypassed.

If APRM channels 3 or 4 are bypassed, the output to the meters/recorders are still available.

(13) The alarm status of each flow channel is indicated on the APRM and RBM instruments. This is indicated on the header display and on the TRIP and INOP status screens.

(14) All of the flow alarms are non-latching.

(15) The flow transmitters are powered from the APRM channel power supplies. If no power is available to the APRM instrument, then no recirculation flow indication will be available from that instrument. — RPS

(16) Each APRM sends its total flow signal to both RBMs for the flow compare function and for signal transmission to the process computer. — RBM

(17) Each RBM chassis compares the four total flows (one from each APRM). — Inverse video

(18) Each RBM uses the flow signal it receives from its "home" APRM, or alternate APRM if "home" APRM is unavailable. Additional information is presented in the RBM section of this lesson plan. — Home means primary/normal APRM input

(19) Each APRM compares its own processed flow signal to a high set point. A rod block and alarm are issued on upscale trip.

Flow Upscale is > 107% or upscale

(20) Bypass of the APRM channel bypasses the flow biasing function. No separate flow signal bypass.

(21) Total Recirculation Flow value is used for its flow biased trips, rod blocks, and alarms. The flow inputs for the OPRM functions will be discussed later in the OPRM section of this lesson plan.

BFN Unit 2	Average Power Range Monitoring	2-OI-92B Rev. 0036 Page 15 of 28

6.0 SYSTEM OPERATIONS

NOTES

1) Only one APRM/OPRM can be bypassed at a time.
2) All operations are performed on Panel 2-9-5 unless specifically stated otherwise.
3) In order to prevent inadvertent rod withdrawal block or Reactor scram while operating APRM BYPASS selector switch, always ensure the previously bypassed channel returns to normal status by observing the BLUE bypassed lights on Panel 2-9-14 Voters are extinguished prior to selecting any other channel to be bypassed. After bypassing a channel, the applicable BLUE BYPASSED status lights on Panel 2-9-14 Voters should be illuminated prior to testing, operating, or working on that channel.

6.1 Bypassing APRM/OPRM Channel

CAUTION

[QA/C] SPP-10.4 requires approval of the Plant Manager or his designee prior to any planned operation with APRMs bypassed unless bypassing is specifically allowed within approved procedures. [ISE-NPS-92-R01]

[1] **REVIEW** all precautions and limitations.
REFER TO Section 3.0. ☐

[2] **PLACE** APRM BYPASS, 2-HS-92-7B/S3, to desired channel to be bypassed. ☐

[3] **CHECK** BLUE BYPASSED lights illuminated on Panel 2-9-14, Voters. ☐

[4] **VERIFY** white bypass light on Panel 2-9-5 is illuminated. ☐

BFN Unit 2	Rod Block Monitor	2-OI-92C Rev. 0033 Page 13 of 16

6.2 Manually Bypassing RBM Channels

CAUTION

[QA/C] SPP-10.4 requires approval of the Plant Manager or his designee prior to any planned operation with RBMs bypassed unless bypassing is specifically allowed within approved procedures. [ISE-NPS-92-R01]

[1] **REVIEW** all precautions and limitations in Section 3.0. ☐

[2] **PLACE** RBM BYPASS, 2-HS-92-7B/S2, to desired channel to be bypassed. ☐

[3] **CHECK** BYPASSED light illuminated for channel bypassed on Panel 2-9-14 in Inverse Video, and the WHITE BYPASS light illuminated on Panel 2-9-5. ☐

6.3 Returning RBM to Service from Bypassed Condition

[1] **REVIEW** all precautions and limitations in Section 3.0. ☐

[2] **PLACE** RBM BYPASS, 2-HS-92-7B/S2, to neutral (off). ☐

[3] **CHECK** previously bypassed channel BYPASSED lights extinguished. ☐

[4] **OBSERVE** RBM channel display in operation (Inverse Video) and recorder indicating. ☐

7.0 SHUTDOWN

None

8.0 INFREQUENT OPERATIONS

None

3.2.5 Operations Shift Managers (continued)

13. Contacting Reactor Engineering to provide support when their evaluation of the planned maneuver or other reactivity evolution warrants Reactor Engineering support.

14. Attend Reactivity Management Review Board when requested.

3.2.6 Unit Supervisors

A. Are sensitive to the reactivity effects that may result from normal and infrequent evolutions.

B. Ensure that planned work activities have received appropriate reactivity management reviews and the necessary controls have been implemented into the work packages and/or procedures, including contingency or compensatory actions as needed.

C. Place emphasis during turnover and control board walk downs on items important to reactivity management.

D. Have the authority to terminate any activity in which the effects on reactivity control are unknown or non-conservative.

E. Have the responsibility and authority to trip the unit if there is uncertainty as to the unit's status with respect to the control of reactivity and control of the plant.

F. Ensure that the specific details of events or equipment problems related to the control of reactivity are recorded and initiates corrective actions.

G. Maintains a cautious approach to the adjustment or interpretation of power indication by questioning the reasons behind discrepancies that may exist between power measurements.

H. Evaluate the recommendations provided by the Reactivity Control Plan or verbally by the on-call RE. However, the election to take actions more conservative than the recommendations is within the Reactivity Management Philosophy.

I. Ensure all control rod movements are made in a deliberate, carefully controlled manner while constantly monitoring nuclear instrumentation and redundant indications of reactor power and neutron flux.

J. Provide direct oversight (line of sight within normal conversation level distance) for all reactivity manipulations (may be performed by a dedicated SRO for major reactivity evolutions such as reactor startup).

K. Attend Reactivity Management Review Board when requested.

3.2.7 Reactor Operators

A. Place emphasis during turnover and control board surveillance on items important to reactivity management.

NPG Standard Programs and Processes	Reactivity Management Program	SPP-10.4 Rev. 0005 Page 24 of 48

3.9 Reactivity Control During Approach to Criticality (continued)

D. If the approach to criticality is suspended for an extended period of time near the point of criticality, the reactor core shall be made sufficiently subcritical to avoid an inadvertent criticality.

E. In the event of an unexplained change in reactivity during an approach to criticality, the approach to criticality shall cease and the reactor core shall be made sufficiently subcritical to prevent an inadvertent criticality. Approval of the Plant Manager or his designee is required to resume the approach to criticality.

F. Procedural controls shall be in place to ensure that cycle-specific information is appropriately updated in the process computer and offline software used to track reactivity-related parameters.

3.10 Reactivity Control During Power Ascension

A. If discrepancies (outside allowable acceptance criteria) exist between reactor power level indicators, power ascension shall cease until the situation is investigated. Approval of the Plant Manager or his designee is required to resume power ascension.

B. Indications of core thermal power using the neutron monitoring instrumentation shall be compared to alternate indication to verify consistency. Conservative actions in accordance with Technical Specifications shall be taken when indications are inconsistent.

C. Reactor power level increases shall be consistent with fuel vendor requirements.

D. In the event of an unexplained change in reactivity, power ascension shall cease. Limitations on continued operation shall be based upon Technical Specifications and approval of the Plant Manager or his designee is required to resume power ascension.

E. When unexpected core power distribution indications are encountered, the cause of the power distribution anomaly needs to be thoroughly investigated and understood by all concerned participants (i.e., nuclear fuel, reactor engineers and fuel vendor) before the reactor is operated at higher power levels. In all cases where the reactor is operating outside expected parameter limits, line management should seek the advice of the appropriate technical staff and fuel vendor in order to make a conservative decision regarding whether to allow continued reactor operation or a return to power.

3.11 Reactivity Control At Steady-State Conditions

A. Shift Manager has the primary authority over the control of reactivity. The Shift Manager or the Unit Supervisor shall give direction for all changes in reactivity. Any planned reactivity changes implemented in the control room, namely the normal manipulation of reactivity controls, shall be performed under the oversight of a designated SRO.

B. Operation of reactivity controls and other mechanisms which may affect the reactivity or power level of the reactor shall only be accomplished with the knowledge and consent of the Licensed Operator "at the controls" and with the approval of the On-Duty Unit Supervisor.

Examination Outline Cross-reference:	Level	RO	SRO
239002G2.4.2	Tier #		2
Knowledge of system set points, interlocks and automatic actions associated with EOP entry conditions: SRVs	Group #		1
	K/A #	239002G2.4.2	
	Importance Rating	4.5	4.6

Proposed Question: **SRO #14**

A loss of all off-site power and LOCA have occurred on Unit 1 which resulted in the following plant conditions:

- RPV pressure 960 psig and stable.
- RPV water level (-) 134 inches and lowering.
- Drywell pressure 14 psig and rising.
- Drywell temperature 285 ^{O}F and rising.
- Suppression Pool level 15 feet
- Suppression Pool temperature 175 ^{O}F and rising.
- Execution of 1-EOI-1, "RPV Control" and 1-EOI-2, "Primary Containment Control" is in progress.

Which ONE of the following describes the required actions based on the given conditions?

A. Exit 1-EOI-1 path RC/P and execute 1-EOI-C2, "Emergency Depressurization."

B. Execute 1-EOI-1 Step RC/P-3 and Rapidly Depressurize the RPV.

C. Execute 1-EOI-1 Step RC/P-7 and lower RPV pressure to stay in the safe area of the HCTL Curve.

D. Remain in 1-EOI-1, "RPV Control" and execute 1-EOI-Appendix 11B, "Re-Open MSIVs" concurrently.

Proposed Answer: **A**

Explanation:

a. Correct answer.

b. Incorrect. Rapid depressurization is an anticipatory response to prevent conditions which require Emergency Depressurization. DW temp above 280 ^{O}F precludes anticipation of ED.

c. Incorrect. Although the guidance in this step will apply if SP temperature continues to rise, the action to perform Emergency Depressurization will eliminate any possibility of reaching the unsafe area of the HCTL curve.

d. Incorrect. Although the actions to re-open MSIVs may eventually be performed as an option for long term decay heat removal, the requirement to perform Emergency Depressurization exists right now and must take priority.

Technical Reference(s): 1-EOI-1, "RPV Control" (Attach if not previously provided)
1-EOI-2, "Primary Containment Control"

Proposed references to be provided to applicants during examination: None

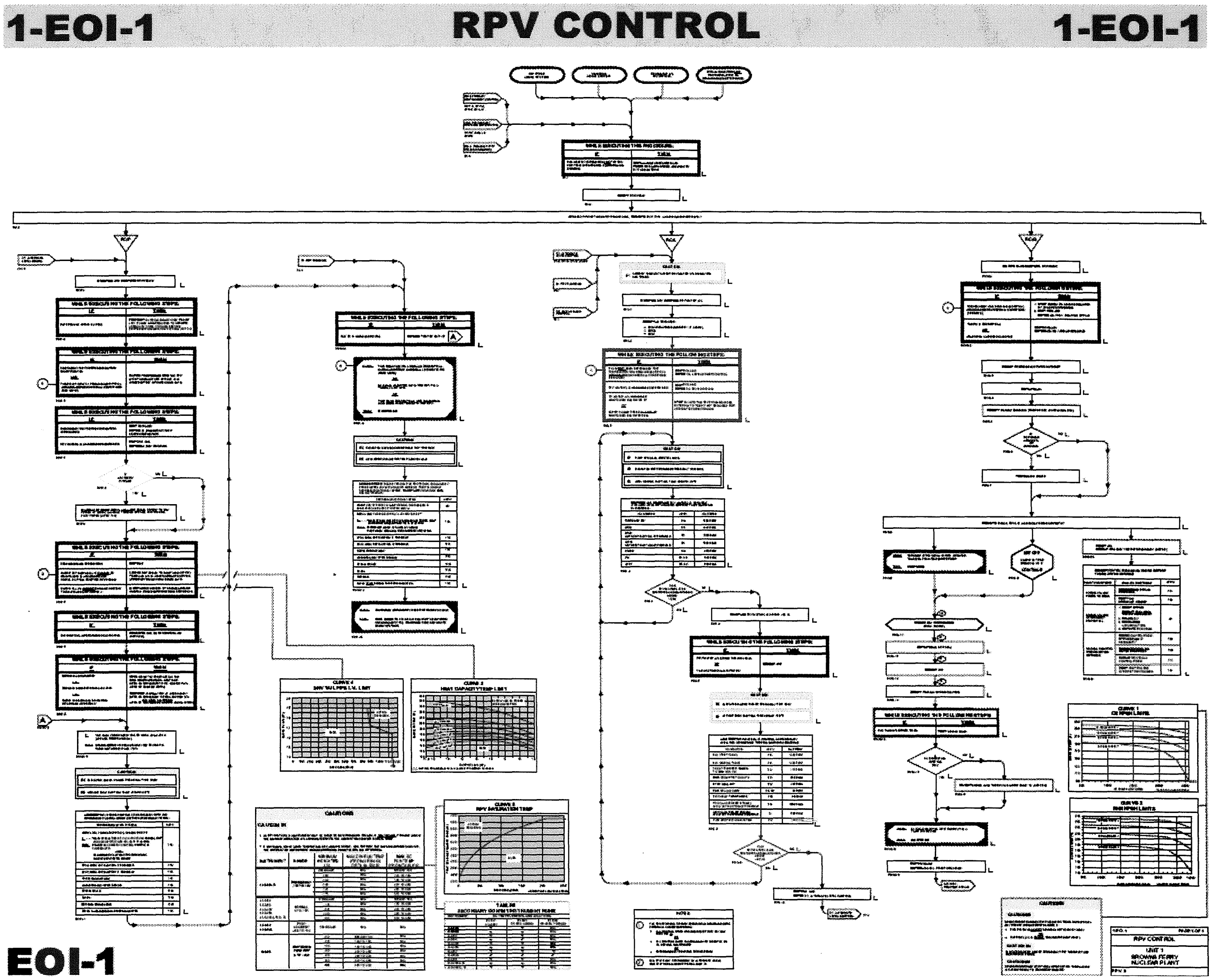
Question Source: Bank #
Modified Bank # (Note changes or attach parent)
New 7/16/2008 RMS

Question History: Last NRC Exam

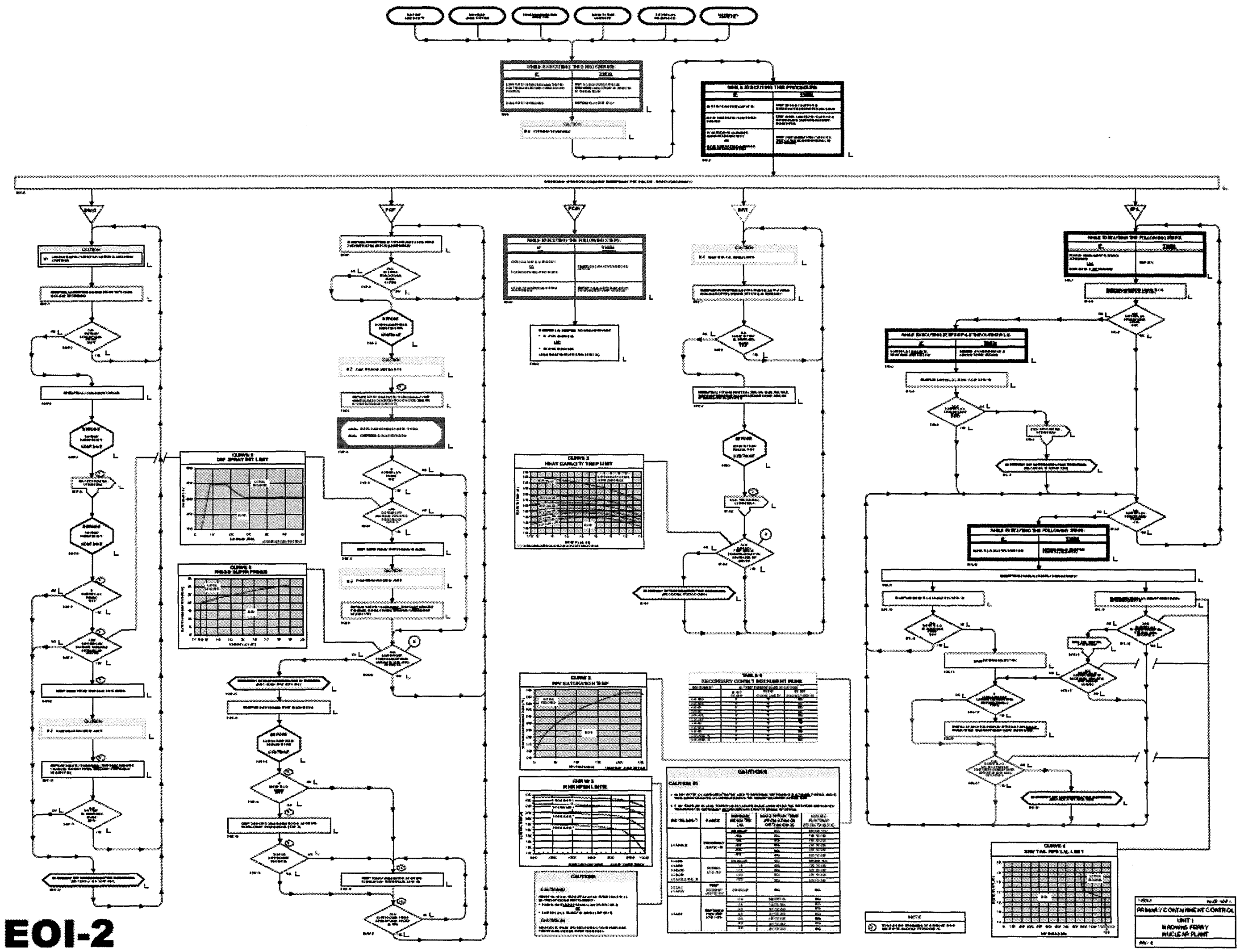
Question Cognitive Level: Memory or Fundamental Knowledge
Comprehension or Analysis X

10 CFR Part 55 Content: 55.41
55.43 X

Comments: I consider this a K/A match by requiring the candidate to recognize entry requirements to EOI-C2 to use SRVs to Emergency Depressurize based on Drywell High Temperature limits (set points).


1-EOI-1
RPV CONTROL
1-EOI-1
EOI-1

1-EOI-2 PRIMARY CONTAINMENT CONTROL 1-EOI-2



Examination Outline Cross-reference:	Level	RO	SRO
259002A2.01	Tier #		2
Ability to (a) predict the impacts of the following on the Reactor Water Level Control system and (b) based on these predictions, use procedures to correct, control, or mitigate the consequences of those abnormal operations: Loss of any number of main steam flow inputs.	Group #		1
	K/A #	259002A2.01	
	Importance Rating	3.3	3.4

Proposed Question: **SRO #15**

Unit-2 is operating at 100% rated power when the following annunciators are received:

- REACTOR WATER LEVEL ABNORMAL (9-5A W8)
- MAIN STEAM LINE VS. MAIN TURB STEAM FLOW MISMATCH (9-5B W24)
- RFWCS INPUT FAILURE (9-6C W14)

Which ONE of the following describes the current status of Reactor Water Level and the required actions to mitigate this failure?

Actual reactor water level is ____(1)____ than normal. Coordinate with Instrument Mechanics and direct bypassing ________(2)________.

	(1)	(2)
A.	higher	Main Steam Line Flow instrument in accordance with 2-OI-3, "Reactor Feedwater System."
B.	higher	Feedwater Line Flow instrument in accordance with 2-AOI-3-1, "Loss of Reactor Feedwater or Reactor Water Level High/Low."
C.	lower	Main Steam Line Flow instrument in accordance with 2-OI-3, "Reactor Feedwater System."
D.	lower	Feedwater Line Flow instrument in accordance with 2-AOI-3-1, "Loss of Reactor Feedwater or Reactor Water Level High/Low."

Proposed Answer: **C**

Explanation:

a. Part (1) is incorrect. A failure of the feedwater flow instrument would not result in a steam line vs. turb steam flow mismatch. Both of the other two annunciators would be valid for either failure. If the failure is a steam flow transmitter, RWL would be lower than normal due to steam flow being higher than indicated. Part (2) is correct. The transmitter is bypassed using 2-OI-3.

b. Part (1) is incorrect as in (a) above. Part (2) is incorrect for two reasons. First, the FW flow transmitter is not the cause of these indications. Second, 2-AOI-3-1 directs bypassing the failed instrument, but the actual steps to accomplish that action are directed by 2-OI-3, so the procedure reference is incorrect.

c. Correct answer.

d. Part (1) is correct. A failed steam flow transmitter will result in lower RWL due to a reduction in actual feed flow to compensate for a reduction in indicated steam flow. Part (2) is incorrect as stated in (b) above.

Technical Reference(s): 2-OI-3, 2-AOI-3-1, ARP 9-6C W 14 (Attach if not previously provided)

ARP 9-5A W8, ARP 9-5B W24

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/17/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

BFN Unit 2	Panel 9-5 2-XA-55-5A	2-ARP-9-5A Rev. 0042 Page 13 of 45

REACTOR WATER LEVEL ABNORMAL 2-LA-3-53

8

(Page 1 of 1)

Sensor/Trip Point:

RFW Control System

2-RLY-003-0053LL	≤ 27 inches
2-RLY-003-0053LH	≥39 inches

Average of valid Narrow Range Level signals from RFW Control System. Signals originate from 2-LT-3-53, 3-60, 3-206 and 3-253.

Sensor Location:
2-RLY-003-0053LL in Panel 2-9-97 (Unit 2 Control Room)
2-RLY-003-0053LH in Panel 2-9-97 (Unit 2 Control Room)
2-LT-3-53 on Panel 25-5B (Rx Bldg El 593', R10-S)
2-LT-3-60 on Panel 25-6B(Rx Bldg El 593', R12-P)
2-LT-3-206 on Panel 2-925-426(Rx Bldg El 593', R10-T)
2-LT-3-253 on Panel 25-6D(Rx Bldg El 593', R12-R)

Probable Cause:
A. Reactor water level high or low.
B. Malfunction of sensor.

Automatic Action:
None (Reactor scram on low level at +2 in)
(Main Turbine/RFPT trip and subsequent scram if ≥30% Reactor Power on high level at +55 in)

Operator Action:
A. **VALIDATE** Reactor water level hi/low using multiple indications including Average Narrow Range Level on 2-XR-3-53 recorder, 2-LI-3-53, 2-LI-3-60, 2-3-206 and 2-LI-3-253 on Panel 2-9-5. ☐
B. **IF** alarm is valid, **THEN REFER TO** 2-AOI-3-1 or 2-OI-3. ☐
C. **IF** 2-LI-3-53, 2-LI-3-60, 2-LI-3-206 and 2-LI-3-253 has failed or is invalid, **THEN** with SRO permission, **BYPASS** the affected level instrument. **REFER TO** 2-OI-3 Section 8.2. ☐

References:

0-45N620-6	2-729E895-10	2-47E610-46-1
2-729E895-1	2-AOI-3-1	2-OI-3

BFN Unit 2	Panel 9-6 2-XA-55-6C	2-ARP-9-6C Rev. 0016 Page 17 of 41

RFWCS
INPUT FAILURE

2-LA-46-5D

14

(Page 1 of 2)

Sensor/Trip Point:

2-RLY-46-5D - A process input to the RFW Control System declared Bad or Invalid. A signal is declared bad when it has failed or is off scale.
A signal is declared invalid when it fails the validation process described in 2-OI-3 Illustration 8.

Sensor Location: Panel 2-9-97 (Behind Panel 2-9-5).

Probable Cause: Any of the following inputs will cause this annunciator to alarm:

A. RFP A, B, or C Discharge Flow bad or invalid.
B. RFW A or B Line Flow bad or invalid.
C. Main Steam Line Flow A, B, C, or D bad or invalid.
D. Reactor Pressure (Wide Range) A, B, or C bad or invalid.
E. Reactor Pressure (Narrow Range) bad or invalid.
F. Reactor Water Level A, B, C or D bad or invalid.
G. Turbine First Stage Pressure bad.
H. RFW A or B Line Temperature bad.

Automatic Action:

A. RFWCS bypasses a bad or invalid signal from the system.
B. Amber light on the following instruments illuminates when the signal has been automatically bypassed:
  - RFP Discharge Flows, 2-FI-3-20,13,6 (Panel 2-9-6).
  - RFW Line Flows, 2-FI-3-78A, 78B (Panel 2-9-5).
  - Main Steam Line Flows, 2-FI-46-1, 2, 3, 4(Panel 2-9-5).
  - WR Reactor Pressure 2-PI-3-54, 61,207 (Panel 2-9-5).
  - Reactor Water Level 2-LI-3-53, 60,206,253 (Panel 2-9-5).

Operator Action:

A. **VERIFY** RFWCS continues to maintain Reactor Water level.
B. **IDENTIFY** bad/invalid signal by checking Control Room instrumentation and/or ICS. **REFER TO** ATTACHMENT 1 on next page for list of RFWCS instrumentation. **REFER TO** ICS RX FW LVL CONTROL SYS display (FWLCS).
C. **REQUEST** assistance from Site Engineering.
D. **BYPASS** the bad/invalid signal with Unit Supervisor approval. REFER TO 2-OI-3.

BFN Unit 2	Panel 9-5 2-XA-55-5B	2-ARP-9-5B Rev. 0023 Page 28 of 43

MAIN STEAM LINE
VS. MAIN TURB
STEAM FLOW
MISMATCH
2-XA-46-7

24

(Page 1 of 1)

Sensor/Trip Point:

2-RLY-046-0007 Total Steam Flow to Turbine First Stage Pressure (flow equivalent) deviate by more than ±0.8 Mlb/hr for 30 seconds. This is determined by the RFW Control System by signals originating from 2-PT-1-81 and 2-FT-1-13, 25, 36, and 50.

Sensor Location:

2-RLY-046-0007 in Panel 2-9-97(Unit 2 Control Room)
2-FT-1-13 on 2-LPNL-925-0056A (Rx Bldg El 541 NE QUAD)
2-FT-1-25 on 2-LPNL 925-0056A (Rx Bldg El 541 NE QUAD)
2-FT-1-36 on 2-LPNL-925-0056B (Rx Bldg El 541 NE QUAD)
2-FT-1-50 on 2-LPNL-925-0056B (Rx Bldg El 541 NE QUAD)
2-PT-1-81 on Panel 25-111(Turb Bldg El 586 T-10-J-Line)

Probable Cause:

A. Small steam line break.
B. Unit startup (Mode 2) or shutdown (Mode 3).
C. Bypass Valves Open.
D. Sensor malfunction.
E. Main Steam Line Flow instrument failed (2-FI-46-1 through 46-4 on Panel 2-9-5).

Automatic Action:

None

Operator Action:

A. **IF** a Main Steam Line Flow instrument has failed or is invalid, **THEN** with SRO permission, **BYPASS** the affected instrument. **REFER TO** 2-OI-3 Section 8.4. ☐
B. **CHECK** main steam tunnel temperature on LEAK DETECTION SYSTEM TEMPERATURE, 2-TI-69-29, Panel 2-9-21. ☐
C. **VERIFY** Rx and Turb Bldg fans on fast speed. ☐
D. **DISPATCH** personnel to determine leak location. ☐
E. **IF** steam leak presents personnel safety hazard or radiological problem, **THEN**
EVACUATE the affected area. ☐
F. **IF** leak CANNOT be isolated, **THEN**
PLACE Reactor in HOT STANDBY CONDITION (Mode 3) with MSIVs closed, or COLD SHUTDOWN CONDITION (Mode 4). ☐
G. **REFER TO** Tech Spec Table 3.3.6.1-1. ☐

References:

2-47E610-1-1	2-729E895-10	2-45E620-6
2-47E610-46-1	2-OI-3	Technical Specifications

BFN Unit 2	Loss of Reactor Feedwater or Reactor Water Level High/Low	2-AOI-3-1 Rev. 0020 Page 8 of 16

5.0 LOW REACTOR WATER LEVEL OR LOSS OF FEEDWATER (continued)

[2] **IF** Feedwater Flow signal fails (FI-3-78A, FI-3-78B), **THEN**

PERFORM the following:

A. With SRO's permission, **REFER TO** 2-OI-3 and **BYPASS** failed Feedwater Flow Instrument in Unit 1&2 Computer Room or Unit 2 Aux Instrument Room. ☐

[2.1] **IF** both Feedwater Flow Instruments fail, **THEN**

VERIFY level control transfers to SINGLE ELEMENT. ☐

[3] **IF** Steam Flow signal fails (FI-46-1,2,3,4), **THEN**

PERFORM the following:

[3.1] With SRO's permission, **REFER TO** 2-OI-3 and **BYPASS** failed Steam Flow Instrument in Unit 1&2 Computer Room or Unit 2 Aux Instrument Room. ☐

[3.2] **IF** three Steam Flow Instruments fail, **THEN**

VERIFY level control transfers to SINGLE ELEMENT. ☐

[4] **IF** Reactor Water Level signal fails (LI-3-53, 60, 206, 253), **THEN**

PERFORM the following: ☐

[4.1] With SRO's permission, **REFER TO** 2-OI-3 and **BYPASS** failed level instrument on Panel 2-9-5. ☐

[4.2] **IF** four Reactor Water Level instruments fail, **THEN**

PERFORM the following:

[4.2.1] **VERIFY** level control transfers to MANUAL. ☐

[4.2.2] **MAINTAIN** Reactor Water Level in MANUAL mode. ☐

[5] **VERIFY** closed all Safety/Relief Valves. ☐

BFN Unit 2	Reactor Feedwater System	2-OI-3 Rev. 0118 Page 83 of 209

8.4 Bypassing RFWCS Main Steam Flow Instrumentation

CAUTION

Bypassing steam flow signal for a partially or completely isolated steam line could result in the RFW Control System raising Reactor Water Level to Main Turbine/RFPT high water level trip setpoint when in THREE ELEMENT control. Even though isolated steam line will produce a steam flow signal of low value, the signal is still valid and is used by the RFW Control System when in THREE ELEMENT control, for calculating average steam line flow.

NOTES

1) RFW Control System will allow up to two Main Steam Line Flow instruments to be bypassed at a time. Should a third Steam Flow instrument be bypassed or fail with two other instruments bypassed, RFWCS control will automatically transfer to SINGLE ELEMENT.
2) Illustration 8 can be referred to for general information on RFWCS instrumentation.

[1] **REQUEST** assistance from Tech Support and IMs. ☐

[2] **OBTAIN** Unit Supervisor approval. ☐

[3] **BYPASS** any of the following Main Steam Line Flow instruments at AW51 Work Station in Unit 1/2 Computer Room or at Panel 2-9-18 in Unit 2 Auxiliary Instrument Room:

- LINE A, 2-FI-46-1 ☐
- LINE B, 2-FI-46-2 ☐
- LINE C, 2-FI-46-3 ☐
- LINE D, 2-FI-46-4 ☐

[4] **CHECK** amber light illuminated on steam line flow instrument bypassed (Panel 2-9-5). ☐

[5] **IF** Steam line flow instrument was bypassed due to signal failure, **THEN** (Otherwise N/A)

CHECK RFWCS INPUT FAILURE annunciation, 2-XA-55-6C Window 14, will reset (N/A if annunciation was in alarm prior to signal failure). ☐

[6] **VERIFY** RFW Control System continues to maintain Reactor Water level. ☐

BFN Unit 2	Reactor Feedwater System	2-OI-3 Rev. 0118 Page 84 of 209

8.5 Bypassing RFWCS RFW Line Flow Instrumentation:

NOTES

1) The RFW Control System will allow up to one RFW Line Flow instrument to be bypassed at a time. With one instrument bypassed, should the other Feed Line Flow instrument be bypassed or fail, RFWCS control will automatically transfer to SINGLE ELEMENT.

2) Illustration 8 can be referred to for general information on RFWCS instrumentation.

[1] **REQUEST** assistance from Tech Support and IMs. ☐

[2] **OBTAIN** Unit Supervisor approval. ☐

[3] With Unit Supervisor approval, **BYPASS** any one of the following Feed Line Flow instruments at AW51 Work Station in Unit 1/2 Computer Room or at Panel 2-9-18 in Unit 2 Auxiliary Instrument Room:

- LINE A, 2-FI-3-78A ☐
- LINE B, 2-FI-3-78B ☐

[4] **CHECK** amber light illuminated on the Feed Line Flow instrument bypassed (Panel 2-9-5). ☐

[5] **IF** Feed Line Flow instrument was bypassed due to signal failure, **THEN** (Otherwise N/A)

CHECK RFWCS INPUT FAILURE annunciation, 2-XA-55-6C Window 14, will reset (N/A if annunciation was in alarm prior to signal failure). ☐

[6] **VERIFY** RFW Control System continues to maintain Reactor Water level. ☐

BFN Unit 2	Reactor Feedwater System	2-OI-3 Rev. 0118 Page 197 of 209

Illustration 8
(Page 3 of 7)
RFWCS Instrumentation

2.3 System Operation

The RFW Control System will use a Main Steam Line Flow signal provided the system determines signal to be good and valid. A **GOOD** steam flow signal is one that has **NOT** failed and is on scale. A **VALID** steam flow signal is determined by a validation process described in the next paragraph.

Total Steam Flow is validated by comparison to Turbine First Stage Pressure signal steam flow equivalent. If those two signals differ by more than $.8 \times 10^6$ lbm/hr for more than 3 seconds AND Total Steam Flow is greater than 19%, then each of the Steam line flow signals will be compared to average steam line flow. If any individual signal deviates from the average by more than 1.2×10^6 lbm/hr, then the signal is declared invalid and is automatically bypassed.

2.4 Failure Mechanisms

When the RFWCS declares a Steam Line Flow signal bad or invalid, the flow instrument is automatically bypassed. The amber light on the affected instrument will illuminate and the RFWCS INPUT FAILURE annunciation (2-XA-55-6C, window 14) will alarm.

When the RFWCS declares the Turbine First Stage Pressure signal to be bad, the RFWCS INPUT FAILURE annunciation (2-XA-55-6C, window 14) will alarm.

The following events will automatically transfer RFWCS control to SINGLE ELEMENT:

- Total Steam Flow < 19%.
- More than two Steam line flows declared invalid.
- If 1 or 2 steam line flows are invalid AND Turbine First Stage Pressure is invalid.

When Total Steam Flow to Turbine First Stage Pressure deviates by more than $.8 \times 10^6$ lbm/hr for more than 30 seconds, MAIN STEAM LINE VS STEAM FLOW MISMATCH annunciation (2-XA-55-5B, window 24) will alarm.

BFN Unit 2	Reactor Feedwater System	2-OI-3 Rev. 0118 Page 199 of 209

Illustration 8
(Page 5 of 7)

RFWCS Instrumentation

3.3 System Operation

RFW Control System will use a Feedwater line flow signal provided the signal is good and valid. A GOOD line flow signal is one that has not failed and is on scale. A VALID signal is determined by a validation process described in the next paragraph.

Individual Feedwater Line Flows are validated by comparison to each other. If line flows deviate by more than.8 Mlbm/hr and Total Steam Flow is > 19% rated, then each Feedwater line flow is validated against one half of the total of the valid individual RFP discharge flows. If either Feedwater Line Flow signal deviates from the total of the RFP discharge flows by more than .8 x 10^6 lbm/hr, then Feedwater Line Flow signal is invalid and bypassed by the system.

RFP discharge flows are used for the auto flow balancing feature of the RFW Control System. Individual flows are subtracted from the operator supplied flow bias with resultant error signal sent to individual RFP flow balance blocks in RFWCS.

RFP discharge flow signals are also used for controlling RFP Minimum Flow Valves. The associated minimum flow valve will open when RFP discharge flow falls below 2000 gpm and close when RFP discharge flow exceeds 3000 gpm. RFP Discharge Flows are utilized by the Recirc System for 75% Pump Runback (any individual RFP Discharge Flow < 19% AND Reactor Level < 27 inches).

3.4 Failure Mechanisms

When RFWCS declares Feedwater Line Flow or RFP Discharge Flow signal bad or invalid, the signal is automatically bypassed (amber light illuminates on the instrument) and RFWCS INPUT FAILURE annunciation (2-XA-55-6C, window 14) will alarm.

When RFWCS declares a RFW Line Temperature signal bad, RFWCS INPUT FAILURE annunciation (2-XA-9-6C, window 14) will alarm.

If both Feedwater Line Flows are declared bad or invalid, then RFWCS will automatically transfer to SINGLE ELEMENT control.

If both temperature inputs are lost from the associated Feedwater Line or there is a deviation between the two sensors on the same Feedwater Line of greater than 5°F then the average temperature signal is declared bad by the system. A default temperature signal of – 380°F is produced for density compensation.

If RFP Discharge Flow signal is bad, the minimum flow valve will open.

Examination Outline Cross-reference:	Level	RO	SRO
239001G2.2.25	Tier #		2
Knowledge of the bases in Technical Specifications for limiting conditions for operations and safety limits: Main and Reheat Steam.	Group #		2
	K/A #	239001G2.2.25	
	Importance Rating	3.2	4.2

Proposed Question: **SRO #16**

Which ONE of the following describes the Technical Specification limits for closure times for the Main Steam Isolation Valves (MSIVs) and the bases for that limit?

The MSIVs are designed to close _____(1)_____ in order to _______(2)_______.

	(1)	(2)
A.	faster than 3 seconds	minimize the radiological dose following a DBA LOCA.
B.	faster than 5 seconds	minimize the mass loss following a DBA LOCA.
C.	slower than 3 seconds	minimize the RPV pressure transient following a Group I Isolation.
D.	slower than 5 seconds	minimize Primary Containment pressure following a steam line break.

Proposed Answer: **C**

Explanation:

a. Part (1) is incorrect. MSIV closure time is $\geq$ 3 seconds and $\leq$ 5 seconds. Part (2) is incorrect. The accident of concern for minimizing radiological dose is a steam line break outside containment, not a DBA LOCA. In that case the limit is $\leq$ 5 seconds, not $\leq$ 3 seconds.

b. Part (1) is correct for a Main Steam Line Break but not for a DBA LOCA. The mass lost during a DBA LOCA is from the severed Recirculation Loop which is essentially unaffected by MSIV closure times.

c. Correct answer.

d. Part (1) is incorrect. The FSAR analysis for a steam line break assumes a 10.5 second closure time for conservatism but that is not the Tech Spec limit.

Technical Reference(s): FASR Chapter 14.6 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/18/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge X

Comprehension or Analysis

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.5	Verify the isolation time of each power operated, automatic PCIV, except for MSIVs, is within limits.	In accordance with the Inservice Testing Program
SR 3.6.1.3.6	Verify the isolation time of each MSIV is ≥ 3 seconds and ≤ 5 seconds.	In accordance with the Inservice Testing Program
SR 3.6.1.3.7	Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.	24 months
SR 3.6.1.3.8	Verify a representative sample of reactor instrumentation line EFCVs actuate to the isolation position on a simulated instrument line break signal.	24 months
SR 3.6.1.3.9	Remove and test the explosive squib from each shear isolation valve of the TIP System.	24 months on a STAGGERED TEST BASIS
SR 3.6.1.3.10	Verify leakage rate through each MSIV is ≤ 100 scfh and that the combined leakage rate for all four main steam lines is ≤ 150 scfh when tested at ≥ 25 psig.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.11	Verify combined leakage through water tested lines that penetrate primary containment are within the limits specified in the Primary Containment Leakage Rate Testing Program.	In accordance with the Primary Containment Leakage Rate Testing Program

in addition to those specified for the loss of coolant accident described in paragraph 14.6.3.1.)

a. The reactor is assumed to be initially operating at the conditions specified in Table 14.6-3. Tables 14.6-4 and 14.6-5 provide additional conditions that apply for the short term containment response and long term containment response, respectively.

b. The reactor is assumed to go subcritical at the time of accident initiation due to void formation in the core region. Scram also occurs in less than one second from receipt of the high drywell pressure and low water level signals, but the difference in shutdown time between zero and one second is negligible.

c. The sensible heat released in cooling the fuel to the normal primary system operating saturation temperature and the core decay heat were included in the reactor vessel depressurization calculation. Initial high vessel pressure increases the calculated flow rates out of the break; this is conservative for containment analysis purposes.

d. The main steam isolation valves were assumed to start closing at 0.5 seconds after the accident, and the valves were assumed to be fully closed in the shortest possible time of three seconds following closure initiation. Actually, the closures of the main steam isolation valves are expected to be the result of low water level, so these valves may not receive a signal to close for over four seconds; and the closing time could be as high as 10 seconds. By assuming rapid closure of these valves, the reactor vessel is maintained at a high pressure which maximizes the discharge of high energy steam and water into the primary containment.

e. For the short term containment response analysis, the feedwater flow is assumed to coast down to zero at four seconds into the event. This conservatism is used because the relatively cold feedwater flow, if considered to continue, tends to depressurize the reactor vessel, thereby, reducing the discharge of steam and water into the primary containment.

f. For the long term containment response analysis, the reactor feedwater flow into the reactor continues until all the high energy feedwater (water that would contribute to heating the pool) is injected into the vessel.

g. The pressure response of the containment is calculated assuming:

   1. Thermodynamic equilibrium in the drywell and pressure suppression chamber. Because complete mixing is nearly achieved, the error

outside the secondary containment. Figure 14.6-7 shows the break location. The analysis of the accident is described in three parts as follows:

a. Nuclear System Transient Effects

This includes analysis of the changes in nuclear system parameters pertinent to fuel performance and the determination of fuel damage.

b. Radioactive Material Release

This includes determination of the quantity and type of radioactive material released through the pipe break and to the environs.

c. Radiological Effects

This portion determines the dose effects of the accident to control room and offsite persons.

14.6.5.1 Nuclear System Transient Effects

14.6.5.1.1 Assumptions

The following assumptions are used in evaluating response of nuclear system parameters to the steam line break accident outside the secondary containment:

a. The reactor is operating at the power associated with maximum mass release.

b. Reactor vessel water level is normal for initial power level assumed at the time the break occurs.

c. Nuclear system pressure is normal for the initial power level.

d. The steam pipeline is assumed to be instantly severed by a circumferential break. The break is physically arranged so that the coolant discharge through the break is unobstructed. These assumptions result in the most severe depressurization rate of the nuclear system.

e. For the purpose of fuel performance, the main steam isolation valves are assumed to be closed 10.5 seconds after the break. This assumption is based on the 0.5 second time required for the development of the automatic isolation signal (high differential pressure across the main steam line flow restrictor) and the 10-second closure time for the valves.

For the purpose of radiological dose calculations, the main steam isolation valves are assumed to be closed at 5.5 seconds after the break. Faster main steam isolation valve closure could reduce the mass loss until finally some other process line break would become controlling. However, the resulting radiological dose for this break would be less than the main steam line break with a five second valve closure. Thus, the postulated main steam line break outside the primary containment with a five second isolation valve closure results in maximum calculated radiological dose and is, therefore, the design basis accident.

f. The mass flow rate through the upstream side of the break is assumed to be not affected by isolation valve closure until the isolation valves are closed far enough to establish limiting critical flow at the valve location. After limiting critical flow is established at the isolation valve, the mass flow is assumed to decrease linearly as the valve is closed.

g. The mass flow rate through the downstream side of the break is assumed to be not affected by the closure of the isolation valves in the unbroken steam lines until those valves are far enough closed to establish limiting critical flow at the valves. After limiting critical flow is established at the isolation valve positions, the mass flow is assumed to decrease linearly as the valves close.

h. Feedwater flow is assumed to decrease linearly to zero over the first five seconds to account for the slowing down of the turbine-driven feedpumps in response to the rise in reactor vessel water level.

i. A loss of auxiliary AC power is assumed to occur simultaneous with the break. This results in the immediate loss of power to the recirculation pumps. Recirculation flow is assumed to coast down with a three second time constant.

14.6.5.1.2 Sequence of Events

The sequence of events following the postulated main steam line break is as follows:

The steam flow through both ends of the break increases to the value limited by critical flow considerations. The flow from the upstream side of the break is limited initially by the main steam line flow restrictor. The flow from the downstream side of the break is limited initially by the downstream break area. The decrease in steam pressure at the turbine inlet initiates closure of the main steam isolation valves within about 200 milliseconds after the break occurs (see Subsection 7.3 "Primary Containment Isolation System"). Also, main steam isolation valve closure signals are generated as the differential pressures across the main steam line flow restrictors increase above isolation setpoints. The instruments sensing flow restrictor differential pressures generate isolation signals within about 500 milliseconds after the break occurs.

Examination Outline Cross-reference:	Level	RO	SRO
245000A2.06	Tier #		2
Ability to (a) predict the impacts of the following on the Main Turbine Gen. / Aux. system and (b) based on those predictions, use procedures to correct, control, or mitigate the consequences of those abnormal conditions or operations: Loss of extraction steam	Group #		2
	K/A #	245000A2.06	
	Importance Rating	2.9	3.1

Proposed Question: **SRO # 17**

Given the following conditions:

- Unit 2 had been operating at 100% rated power for 370 days since refueling.
- The "A" high pressure heater string, 2A1 and 2A2, have been isolated due to a high level and tube leak in the A2 heater. And all required actions have been completed.

Which ONE of the following describes the highest allowable steady state power limitation and most limiting MCPR limit under the current plant conditions?

Maintain _____(1)_____ . The most limiting MCPR limit is ____(2)____.

REFERENCE PROVIDED

	(1)	(2)
A.	less than 95% power in accordance with 2-AOI-6-1A, "High Pressure Feedwater Heater String/Extraction Steam Isolation."	1.50
B.	less than 95% power in accordance with 2-AOI-6-1A, "High Pressure Feedwater Heater String/Extraction Steam Isolation."	1.48
C.	less than 920 MWe in accordance with 2-OI-6, "Feedwater Heating and Misc Drains System" Illustration 1.	1.50
D.	less than 920 MWe in accordance with 2-OI-6, "Feedwater Heating and Misc Drains System" Illustration 1.	1.48

Proposed Answer: **C**

Explanation :

a. Reducing power by 5% is an action required due to the loss of extraction steam, however the limitations in 2-OI-6, Illustration 1 are more limiting for the Steady State conditions specified in the stem. This is determined by recognizing that a tube leak into the heater will result in automatic isolation of extraction steam and manual isolation of feedwater flow through the heater. The most limiting MCPR limit is correct for the current plant conditions.

b. Same as (a) above. In addition, the MCPR limit is incorrect. The limit of 1.48 is for Atrium-10 fuel. GE14 fuel is more limiting. The candidate must recognize, from the given conditions, the current cycle exposure as well as the status of Scram Time Testing. Specifically, if all Tech Spec surveillances are current and satisfactory, Nominal Scram Speed (NSS) limits apply and not Tech Spec Scram Speed (TSSS) limits.

c. Correct answer

d. The power/generator load limit is correct for the given conditions. Since all required actions are complete, the feedwater flow must have been isolated and the limitations of 2-OI-6, Illustration 1 apply. The MCPR limit is incorrect as in (b) above.

Technical Reference(s):	2-OI-6, 2-AOI-6-1A, U2 COLR	(Attach if not previously provided)

Proposed references to be provided to applicants during examination: U2 COLR

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New X RMS 7/6/2008

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

3.0 PRECAUTIONS AND LIMITATIONS (continued)

G. When more than one condensate and condensate booster pump is in service, the tube side of two high or low pressure Feedwater heater strings should not be isolated at the same time.

H. When placing isolated Feedwater heaters in service, Feedwater flow may vary, resulting in reactor water level oscillations.

I. Assuming that throttle steam flow is not changed, the following will occur when a Feedwater heater is removed from service:

1. If a number one Feedwater heater is removed from service, generator output will be higher. This occurs because the normally extracted steam now passes through the low pressure turbine.

2. When other than number one Feedwater heater is removed from service, extraction to the next higher Feedwater heater will be higher because the Feedwater temperature rise across the heater is greater than before. A slightly lower generator output will occur.

3. Turbine thrust bearing loading may be higher due to load imbalance caused by loss of extraction point.

4. Although not likely, a turbine thrust bearing active/passive plate reversal could occur due to load imbalance. If this occurs the turbine thrust bearing trip setpoints should be checked. (REFER TO 2-OI-47).

5. When operating with Feedwater heater(s) out of service there will be a loss of efficiency.

J. The limitations of Illustration 1, Maximum Turbine-Generator Load Allowed When Any Feedwater Heater is Not in Service, shall be followed when removing Feedwater heaters from service.

K. When extraction steam is shut off to a Feedwater heater, generator output must be within the limits of Illustration 1, which is only evaluated for a maximum of 3458 MWt. Additionally, PCIOMR constraints may require a power reduction prior to removal of Feedwater heaters. A reduction of core flow alone should prevent a violation of the envelope, but some power shaping may be necessary.

L. Do not attempt to maintain Feedwater heaters at normal level when the associated level controller is in manual operation for long periods of time.

1. Operation with low level can result in heater damage.

2. Operation with high level will cause loss of efficiency and may result in turbine damage.

BFN Unit 2	High Pressure Feedwater Heater String/Extraction Steam Isolation	2-AOI-6-1A Rev. 0015 Page 5 of 9

4.0 OPERATOR ACTIONS

4.1 Immediate Actions

[1] **REDUCE** Core Thermal Power to ≥ 5% below initial power level to maintain thermal margin. ☐

4.2 Subsequent Actions

[1] **REFER TO** 2-OI-6 for turbine/heater load restrictions. ☐

[2] **REQUEST** Reactor Engineer EVALUATE and ADJUST thermal limits, as required. ☐

> **CAUTION**
>
> Failure to reduce core power if fuel is operating at or near the preconditioned envelope in any region of the core may result in fuel damage.

[3] **ADJUST** reactor power and flow as directed by Reactor Engineer/Unit Supervisor to stay within required thermal and feedwater temperature limits. **REFER TO** 2-GOI-100-12 or 2-GOI-100-12A for the power reduction. ☐

[4] **ISOLATE** heater drain flow from the feedwater heater string by closing the appropriate FEEDWATER HEATER A2(B2)(C2) DRAIN TO HTR A3(B3)(C3), 2-FCV-6-94(95)(96). ☐

[5] **VERIFY** automatic actions occur. **REFER TO** Attachment 1. ☐

[6] **MONITOR** TURB THRUST BEARING TEMPERATURE, 2-TR-47-23, for rising metal temperature and possible active/passive plate reversal. ☐

[7] **DETERMINE** cause which required heater isolation and **PERFORM** necessary corrective action. ☐

[8] **WHEN** the condition which required heater isolation is no longer required, **THEN**

RESTORE affected heater. **REFER TO** 2-OI-6. ☐

BFN Unit 2	Feedwater Heating and Misc Drains System	2-OI-6 Rev. 0077 Page 133 of 142

Illustration 1
(Page 1 of 2)

Maximum Turbine-Generator Load Allowed when any Feedwater Heater is Not in Service

HEATERS OUT (Tube and Shell Side)**

One HP string	920 MWe (79%)
One LP string	920 MWe (79%)
One HP and LP string	920 MWe (79%)

HEATERS OUT (EXTRACTION STEAM ONLY)*

These MWe limits are only evaluated for a maximun of 3458 MWt. A new evaluation will be required for any reactor power greater than 3458 MWt.	**MAXIMUM GENERATOR OUTPUT (MWe)**
2A1, 2B1, 2C1 2A2, 2B2, 2C2 2A3, 2B3, 2C3 — Any Combinations — There are no extraction stm. Isol. vlvs. for Htrs 4 & 5. When Htrs 4 & 5 are mentioned in table this indicates that their extraction bypass valves are opened.	See page two
One Vessel of Number 4 Heater from Either String A, B, or C	**NOT** Limiting
Two Vessel of Number 4 Heater from Any 2 Strings (A, B, or C)	**NOT** Limiting
All Three Vessels of Number 4 Heater	**NOT** Limiting
One Vessel of Number 5 Heater from Either String A, B, or C	**NOT** Limiting
Two Vessel of Number 5 Heater from Any 2 Strings (A, B, or C)	**NOT** Limiting
All Three Vessels of Number 5 Heater	**NOT** Limiting
Any 2 Vessels of No. 5 & No. 4 from Any String	1008
Any 3 Vessels of No. 5 & No. 4 from Any String	1008
Any 4 Vessels of No. 5 & No. 4 from Any String	1008
Any 5 Vessels of No. 5 & No. 4 from Any String	1008
All of No. 5 And All of No. 4	1008
2A3, 2A4, 2A5	1008
All The Vessels of One String i.e., 2A5, 2A4, 2A3, 2A2, 2A1	952

* The limitations apply to the combinations indicated and equivalent combinations. For instance, the restriction for operation with heaters 2A3, 2A4 and 2A5 out of service is equally applicable to operation with heaters 2B3, 2B4 and 2B5 or 2C3, 2C4 and 2C5 out of service.

** It is permissible to operate at power levels above 79% as long as the requirements of Sections 8.1 and/or 8.3 are met.

BFN Unit 2	Feedwater Heating and Misc Drains System	2-OI-6 Rev. 0077 Page 134 of 142

Illustration 1
(Page 2 of 2)

Maximum Turbine-Generator Load Allowed when any Feedwater Heater is Not in Service

<u>HEATERS OUT</u> (EXTRACTION STEAM ONLY)*

These MWe limits are only evaluated for a maximun of 3458 MWt.

2A1	2A2	2A3	2B1	2B2	2B3	2C1	2C2	2C3	MAXIMUM GENERATOR OUTPUT (MWe)
X									NOT Limiting
	X								NOT Limiting
		X							NOT Limiting
	X	X							1064
X	X								NOT Limiting
X	X				X				NOT Limiting
X			X						NOT Limiting
X		X							1064
X	X		X						1064
X	X	X							NOT Limiting
X			X			X			NOT Limiting
X		X	X						1064
X	X		X	X					NOT Limiting
X		X			X				1064
X	X		X			X			NOT Limiting
X	X	X	X						1064
X	X	X			X				1064
X	X	X				X			1064
X	X		X	X		X			1064
X	X	X	X	X					1064
X		X			X			X	1008
X	X	X	X			X			1064
X	X		X	X		X	X		1064
X	X	X	X		X				1064
X	X	X	X	X		X			1064
X		X	X		X			X	1008
X	X	X	X	X	X				1008
X	X	X	X		X	X			1064
X	X	X	X	X		X	X		1064
X	X	X	X		X			X	1064
X		X	X		X	X		X	1008
X	X	X	X	X	X	X			1008
X	X	X	X	X	X			X	1008
X	X	X	X		X	X		X	1008
X	X	X	X	X	X	X	X		1008
X	X	X	X	X	X	X		X	1008
X	X	X	X	X	X	X	X	X	1008

* The limitations apply to the combinations indicated and equivalent combinations. For instance, the restriction for operation with heaters 2A1 and 2A2 out of service is equally applicable to operation with heaters 2B1 and 2B2 or 2C1 and 2C2 out of service. To try to clarify: Any number 1 heater may be substituted for any other number 1 heater, any number 2 heater may be substituted for any other number 2 heater, and any number 3 heater may be substituted for any other number 3 heater. Contact System Engineer for further clarification.

Exposure Range	Scram Speed	$MCPR_P$
BOC to NEOC	NSS TSSS	Table 1 Table 2
BOC to EOC	NSS TSSS	Table 3 Table 4
BOC to CD	NSS TSSS	Table 5 Table 6

a. Scram Speed Dependent Limits (TSSS vs. NSS)

$MCPR_P$ limits are provided for two different sets of assumed scram speeds. The Technical Specification Scram Speed (TSSS) $MCPR_P$ limits are applicable at all times as long as the scram time surveillance demonstrates that the times in Technical Specification table 3.1.4-1 have been met. Nominal Scram Speeds (NSS) may be used as long as the scram time surveillance demonstrates that the times in the following table are met (Ref. 9).

Notch Position	Nominal Scram Speed (seconds)
46	0.42
36	0.98
26	1.60
06	2.90

In demonstrating compliance with this table, the same surveillance requirements from Technical Specification 3.1.4 apply, except that the definition of SLOW rods should conform to the scram speeds in the table above. If conformance to this table is not demonstrated, TSSS $MCPR_P$ limits shall be used.

On initial cycle startup, TSSS limits are used until the successful completion of scram timing confirms that NSS limits may be used.

b. Fuel Type Dependent Limits

Separate $MCPR_P$ limits are provided for the GE14 and A10 fuel types.

Table 1: $MCPR_P$ Limits for BOC to NEOC Exposures – NSS Scram Times
(Applicable up to Core Average Exposure of **27,788 MWd / MTU**)

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
In-Service	100	1.45	1.46
	69	1.58	1.62
	63	1.61	1.64
	58	1.69	1.73
	58	1.78	1.78
	46	1.85	1.89
	30	2.22	2.35
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
RPTOOS	100	1.45	1.46
	69	1.58	1.62
	63	1.61	1.64
	58	1.69	1.73
	58	1.78	1.78
	46	1.85	1.89
	30	2.22	2.35
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
TBVOOS	100	1.49	1.50
	69	1.62	1.66
	63	1.65	1.67
	58	1.71	1.75
	58	1.78	1.78
	46	1.85	1.90
	30	2.23	2.36
	30 (> 50%F)	3.09	3.20
	25 (> 50%F)	3.51	3.64
	30 (≤ 50%F)	2.64	2.79
	25 (≤ 50%F)	2.97	3.18
RPTOOS TBVOOS	100	1.49	1.50
	69	1.62	1.66
	63	1.65	1.67
	58	1.71	1.75
	58	1.78	1.78
	46	1.85	1.90
	30	2.23	2.36
	30 (> 50%F)	3.09	3.20
	25 (> 50%F)	3.51	3.64
	30 (≤ 50%F)	2.64	2.79
	25 (≤ 50%F)	2.97	3.18

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
FHOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.66	1.70
	58	1.75	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS FHOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.66	1.70
	58	1.75	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS FHOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.68	1.72
	58	1.77	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30
RPTOOS TBVOOS FHOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.68	1.72
	58	1.77	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30

Add 0.02 to the above $MCPR_P$ limits for SLO.

REFERENCE MATERIAL

Provided to

CANDIDATE

Browns Ferry Nuclear Plant
Unit 2 Cycle 15

CORE OPERATING LIMITS REPORT (COLR)

TENNESSEE VALLEY AUTHORITY
Nuclear Fuel Division
BWR Fuel Engineering Department

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Approved By:	PORC Chairman	Date:	2/21/07

Revision Log

Revision	Date	Description	Affected Pages
0	2/21/2007	Initial Release for New Cycle	All

1. INTRODUCTION

This Core Operating Limits Report (COLR) for Browns Ferry Nuclear Plant Unit 2 Cycle 15 is prepared in accordance with the requirements of Browns Ferry Technical Specification 5.6.5. This revision of the COLR supports operation at the current licensed thermal power (CLTP) of 3458 MWt which is 105% of original licensed thermal power (OLTP).

The core operating limits presented here were developed using NRC-approved methods (References 2 and 3). One exception to this is an issue with the assumed uncertainty for the GEXL14 CPR correlation. The NRC has identified that the correlation lacked top-peaked axial power shape data in its formulation and in the calculation of the overall correlation uncertainty. As an interim action, an increased GEXL14 uncertainty that incorporates a significant penalty has been calculated and applied to the MCPR Safety Limit (SLMCPR) for this cycle.

Results from the reload analyses for Browns Ferry Nuclear Plant Unit 2 Cycle 15 are documented in Reference 1.

The following core operating and Technical Specification limits are included in this report:

a. Average Planar Linear Heat Generation Rate (APLHGR) Limit
(Technical Specifications 3.2.1 and 3.7.5)

b. Linear Heat Generation Rate (LHGR) Limit
(Technical Specification 3.2.3, 3.3.4.1, and 3.7.5)

c. Minimum Critical Power Ratio Operating Limit (OLMCPR)
(Technical Specifications 3.2.2, 3.3.4.1, and 3.7.5)

d. Average Power Range Monitor (APRM) Flow Biased Rod Block Trip Setting
(Technical Requirements Manual Section 5.3.1 and Table 3.3.4-1)

e. Rod Block Monitor (RBM) Trip Setpoints and Operability
(Technical Specification Table 3.3.2.1-1)

f. Shutdown Margin (SDM) Limit
(Technical Specification 3.1.1)

The Unit 2 Cycle 15 core is composed of AREVA-NP ATRIUM™-10 and Global Nuclear Fuel GE-14™ assemblies. Throughout this document these are referred to as A10 and GE14 with the trademark implied.

2. APLHGR LIMIT (TECHNICAL SPECIFICATIONS 3.2.1 AND 3.7.5)

The APLHGR limit is determined by adjusting the rated power APLHGR limit for off-rated power, off-rated flow, and SLO conditions. The most limiting of these is then used as follows:

$$\text{APLHGR limit} = \text{MIN}\,(\,\text{APLHGR}_{P}\,,\ \text{APLHGR}_{F},\ \text{APLHGR}_{SLO}\,)$$

where:			
	APLHGR_{P}	off-rated power APLHGR limit	[APLHGR_{RATED} * MAPFAC(P)]
	APLHGR_{F}	off-rated flow APLHGR limit	[APLHGR_{RATED} * MAPFAC(F)]
	APLHGR_{SLO}	SLO APLHGR limit	[ALPHGR_{RATED} * SLO_Multiplier]

The off-rated power and flow corrections to the APLHGR limit only apply to the GE14 fuel in the Browns Ferry Unit 2 Cycle 15 core. For that reason, this multiplier is set to 1.0 as shown below for the A10 fuel.

Rated Power and Flow Limits: APLHGR_{RATED}

The APLHGR limits for full power and flow conditions for each type of fuel as a function of exposure are shown in Figures 1-5. The APLHGR limits provided in the COLR figures for the GE14 assemblies are for the most limiting lattice (excluding natural uranium) at each exposure point. The specific values for each GE14 lattice are given in Reference 4. The ATRIUM-10 values are provided in Reference 1.

Bundle Type	Rated Power APLHGR Limit
GE14-P10DNAB416-16GZ (EDB2600)	Figure 1
GE14-P10DNAB416-16GZ (EDB2601)	Figure 2
GE14-P10DNAB416-18GZ (EDB2627)	Figure 3
GE14-P10DNAB417-18GZ (EDB2628)	Figure 4
A10-3920B-14GV70	Figure 5
A10-4227B-15GV80-FBB	Figure 5
A10-4239B-15GV80-FBB	Figure 5
A10-3552B-10GV80-FBB	Figure 5

Off-Rated Power Corrections: $APLHGR_P$

The APLHGR limits for the GE14 fuel lattices are adjusted for off-rated power conditions using the ARTS multiplier, MAPFAC(P). The reduced power multiplier, MAPFAC(P), for the GE14 fuel is provided in Reference 1. No off-rated power correction is required for the A10 rated APLHGR limits.

Product Line	MAPFAC(P)
GE14	Figure 6
A10	1.0

Off-Rated Flow Corrections: $APLHGR_F$

The APLHGR limits for the GE14 fuel lattices are adjusted for off-rated flow conditions using the ARTS multiplier, MAPFAC(F). The reduced flow multiplier, MAPFAC(F) is provided in Reference 1. No off-rated flow correction is required for the A10 rated APLHGR limits.

Product Line	MAPFAC(F)
GE14	Figure 7
A10	1.0

SLO Corrections: $APLHGR_{SLO}$

Single Recirculation Loop Operation (SLO) requires that the rated power APLHGR limit ($APLHGR_{rated}$) be reduced by applying the following multipliers. The GE14 multiplier is provided in Reference 5. The A10 multiplier is provided in Reference 1.

Product Line	SLO Multiplier
GE14	0.90 *
A10	0.85

* The GE14 SLO multiplier of 0.90 is the more limiting of CLTP and EPU values provided in Reference 5. This value bounds operation at CLTP.

Equipment Out-Of-Service (EOOS) Corrections:

The rated APLHGR limits in Figures 1-5 are applicable for operation with all equipment In-Service as well as the following Equipment Out-Of-Service (EOOS) options. This includes combinations of these EOOS options.

In-Service	All equipment In-Service (includes 1 SRVOOS)
RPTOOS	EOC-Recirculation Pump Trip Out-Of-Service
TBVOOS	Turbine Bypass Valve(s) Out-Of-Service
PLUOOS	Power Load Unbalance Out-Of-Service
FHOOS (or FFTR)	Feedwater Heaters Out-Of-Service (or Final Feedwater Temperature Reduction)

Single Recirculation Loop Operation (SLO) requires the application of the SLO multipliers to the rated APLHGR limits as described previously.

The off-rated power corrections [MAPFAC(P)] in Figure 6 is dependent upon the operating status of the Turbine Bypass Valve (TBV) system. For this reason, separate limits are supplied in these figures to be applied for TBVIS (in service) or TBVOOS (out of service) operation. The MAPFAC(P) limits have no dependency on RPTOOS, SLO, FHOOS/FFTR, or PLUOOS.

The off-rated flow corrections [MAPFAC(F)] in Figure 7 bound both equipment In-Service or EOOS operation.

3. LHGR LIMIT (TECHNICAL SPECIFICATION 3.2.3, 3.3.4.1, and 3.7.5)

The LHGR limit is determined by adjusting the rated power LHGR limit for off-rated power and off-rated flow conditions. The most limiting of these is then used, as follows:

LHGR limit = MIN ($LHGR_P$, $LHGR_F$)

where:			
	$LHGR_P$	off-rated power LHGR limit	[$LHGR_{RATED}$ * LHGRFAC(P)]
	$LHGR_F$	off-rated flow LHGR limit	[$LHGR_{RATED}$ * LHGRFAC(F)]

The off-rated power and flow corrections to the LHGR limit only apply to the A10 fuel in the Browns Ferry Unit 2 Cycle 15 core. For that reason, these multipliers for the GE14 fuel is set to 1.0, as shown below.

<u>Rated Power and Flow Limits</u>: $LHGR_{RATED}$

The LHGR limit is fuel type dependent. The limits for these types are given below:

Fuel Type	LHGR Limit
GE14	Figure 8
A10	Figure 9

The A10 LHGR limit is provided in References 1 and 6. The GE14 LHGR limit is provided in References 1 and 7.

<u>Off-Rated Power Corrections</u>: $LHGR_P$

The LHGR limits for the A10 fuel are adjusted for off-rated power conditions using the LHGRFAC(P) multiplier which is provided in Reference 1. The LHGRFAC(P) multiplier is dependent on whether the Turbine Bypass system is in-service (TBVIS) or out-of-service (TBVOOS). No off-rated power correction is required for the GE14 rated LHGR limits.

Product Line	LHGRFAC(P)
GE14	1.0
A10	Figure 10

Off-Rated Flow Corrections: $LHGR_F$

The LHGR limits for the A10 fuel are adjusted for off-rated flow conditions using the LHGRFAC(F) multiplier which is provided in Reference 1. No off-rated flow correction is required for the GE14 rated LHGR limits.

Product Line	LHGRFAC(F)
GE14	1.0
A10	Figure 11

Equipment Out-Of-Service (EOOS) Corrections:

The rated LHGR limits are applicable for operation with all equipment In-Service as well as the following Equipment Out-Of-Service (EOOS) options. This includes combinations of these EOOS options.

In-Service	All equipment In-Service (includes 1 SRVOOS)
RPTOOS	EOC-Recirculation Pump Trip Out-Of-Service
TBVOOS	Turbine Bypass Valve(s) Out-Of-Service
PLUOOS	Power Load Unbalance Out-Of-Service
SLO	Single Recirculation Loop Operation
FHOOS (or FFTR)	Feedwater Heaters Out-Of-Service (or Final Feedwater Temperature Reduction)

The off-rated power corrections [LHGRFAC(P)] in Figure 10 are dependent upon operation of the Turbine Bypass Valve system. For this reason, separate limits are supplied in this figure to be applied for TBVIS or TBVOOS operation. The LHGRFAC(P) limits have no dependency on RPTOOS, PLUOOS, SLO, or FHOOS/FFTR.

The off-rated flow corrections [LHGRFAC(F)] in Figure 11 bound both equipment In-Service or EOOS operation.

4. OLMCPR (TECHNICAL SPECIFICATIONS 3.2.2, 3.3.4.1, AND 3.7.5)

The MCPR Operating Limit (OLMCPR) is calculated to be the most limiting of the flow-dependent MCPR ($MCPR_F$) and power-dependent MCPR ($MCPR_P$).

OLMCPR limit = MAX ($MCPR_F$, $MCPR_P$)

where:	$MCPR_F$	core flow-dependent MCPR limit
	$MCPR_P$	power-dependent MCPR limit

.

$MCPR_F$ limits are provided in Figure 12. $MCPR_P$ limits are provided in Tables 1 through 6.

<u>Flow-Dependent MCPR Limits:</u> $MCPR_F$

The $MCPR_F$ limits are dependent upon:

- Core Flow (% of Rated)
- Max Core Flow Limit (Rated or Increased Core Flow, ICF)
- Fuel Type (GE14 or A10)

The $MCPR_F$ limits are provided in Figure 12. For Unit 2 Cycle 15 the same $MCPR_F$ limits apply to both the GE14 and A10 fuel types. These limits are valid for all EOOS combinations. No adjustment is required to the $MCPR_F$ limits for SLO. The $MCPR_F$ limits are found in Reference 1.

<u>Power-Dependent MCPR Limits:</u> $MCPR_P$

The $MCPR_P$ limits are dependent upon:

- Core Power Level (% of Rated)
- Technical Specification Scram Speed (TSSS) or Nominal Scram Speed (NSS)
- Fuel Type (GE14 or A10)
- Cycle Operating Exposure (NEOC, EOC, and CD - as defined in this section)
- Equipment Out-Of-Service Options
- Two or Single recirculation Loop Operation (TLO vs. SLO)

The $MCPR_P$ limits (Ref. 1) are provided in the following tables, where each table contains the limits for all fuel types and EOOS options (for a specified scram speed and exposure range). The $MCPR_P$ limits are determined from these tables using linear interpolation between the specified powers.

Exposure Range	Scram Speed	$MCPR_P$
BOC to NEOC	NSS TSSS	Table 1 Table 2
BOC to EOC	NSS TSSS	Table 3 Table 4
BOC to CD	NSS TSSS	Table 5 Table 6

a. Scram Speed Dependent Limits (TSSS vs. NSS)

$MCPR_P$ limits are provided for two different sets of assumed scram speeds. The Technical Specification Scram Speed (TSSS) $MCPR_P$ limits are applicable at all times as long as the scram time surveillance demonstrates that the times in Technical Specification table 3.1.4-1 have been met. Nominal Scram Speeds (NSS) may be used as long as the scram time surveillance demonstrates that the times in the following table are met (Ref. 9).

Notch Position	Nominal Scram Speed (seconds)
46	0.42
36	0.98
26	1.60
06	2.90

In demonstrating compliance with this table, the same surveillance requirements from Technical Specification 3.1.4 apply, except that the definition of SLOW rods should conform to the scram speeds in the table above. If conformance to this table is not demonstrated, TSSS $MCPR_P$ limits shall be used.

On initial cycle startup, TSSS limits are used until the successful completion of scram timing confirms that NSS limits may be used.

b. Fuel Type Dependent Limits

Separate $MCPR_P$ limits are provided for the GE14 and A10 fuel types.

c. Exposure Dependent Limits

Exposures are tracked on a Core Average Exposure basis (not Cycle Exposure). The higher exposure $MCPR_P$ limits are always more limiting and may be used for any Core Average Exposure up to the ending exposure.

$MCPR_P$ limits are provided for the following exposure ranges (Ref. 1):

BOC to NEOC	NEOC corresponds to	**27,788 MWd / MTU**
BOC to EOC	EOC corresponds to	**31,075 MWd / MTU**
BOC to CD	CD corresponds to	**32,274 MWd / MTU**

NEOC refers to a Near EOC exposure point.

The EOC exposure point is not the true End-Of-Cycle exposure. Instead it corresponds to a licensing exposure window that exceeds expected end-of-full-power-life.

The CD (CoastDown) exposure point represents a licensing exposure point that exceeds the expected end-of-cycle exposure including cycle extension options.

d. Equipment Out-Of-Service (EOOS) Options

EOOS options included in the $MCPR_P$ limits are:

In-Service	All equipment In-Service (includes 1 SRVOOS)
RPTOOS	EOC-Recirculation Pump Trip Out-Of-Service
TBVOOS	Turbine Bypass Valve(s) Out-Of-Service
RPTOOS+TBVOOS	Combined RPTOOS and TBVOOS
PLUOOS	Power Load Unbalance Out-Of-Service
PLUOOS+RPTOOS	Combined PLUOOS and RPTOOS
PLUOOS+TBVOOS	Combined PLUOOS and TBVOOS
PLUOOS+TBVOOS+RPTOOS	Combined PLUOOS, RPTOOS, and TBVOOS
FHOOS (or FFTR)	Feedwater Heaters Out-Of-Service (or Final Feedwater Temperature Reduction)

For exposure ranges up to NEOC and EOC, additional combinations of $MCPR_P$ limits are also provided that include FHOOS. The CD exposure range assumes application of FFTR, so the CD based $MCPR_P$ limits already include FHOOS.

e. Single-Loop-Operation (SLO) Limits

The $MCPR_P$ limits for SLO are to be increased by 0.02 (Ref. 1).

f. Below Pbypass Limits

Below Pbypass (30% rated power), the $MCPR_P$ limits are dependent upon core flow. One set of $MCPR_P$ limits applies if the core flow is above 50% of rated with a second set that applies if the core flow is less than or equal to 50% rated.

5. APRM FLOW BIASED ROD BLOCK TRIP SETTING (TECHNICAL REQUIREMENTS MANUAL SECTION 5.3.1 AND TABLE 3.3.4-1)

The APRM Rod Block trip setting shall be (Ref. 10):

$S_{RB} \leq (0.66(W-\Delta W) + 61\%)$	Allowable Value
$S_{RB} \leq (0.66(W-\Delta W) + 59\%)$	Nominal Trip Setpoint (NTSP)

where:

S_{RB} = Rod Block setting in percent of rated thermal power (3458 MWt)

W = Loop recirculation flow rate in percent of rated

ΔW = Difference between two-loop and single-loop effective recirculation flow at the same core flow (ΔW=0.0 for two-loop operation)

The APRM Rod Block trip setting is clamped at a maximum allowable value of 115% (corresponding to a NTSP of 113%).

6. ROD BLOCK MONITOR (RBM) TRIP SETPOINTS AND OPERABILITY (TECHNICAL SPECIFICATION TABLE 3.3.2.1-1)

The RBM trip setpoints and applicable power ranges shall be as follows (refs. 10 & 11):

RBM Trip Setpoint	Allowable Value (AV)	Nominal Trip Setpoint (NTSP)	
LPSP	27%	25%	
IPSP	62%	60%	
HPSP	82%	80%	
LTSP - unfiltered - filtered	124.7% 123.5%	123.0% 121.8%	(1),(2)
ITSP - unfiltered - filtered	119.7% 118.7%	118.0% 117.0%	(1),(2)
HTSP - unfiltered - filtered	114.7% 113.7%	113.0% 112.0%	(1),(2)
DTSP	90%	92%	

Notes: (1) These setpoints are based upon an Analytical Limit HTSP of 117% (w/o filter) which corresponds to a MCPR operating limit of **<u>1.42(A10/GE14)</u>**, as reported in section 5.5 of Reference 1. Unit 2 Cycle 15 has had a cycle specific CRWE analysis performed and the table provided in section 5.5 of Reference 1 supercedes the OLMCPR values of references 10 and 12.

(2) The unfiltered setpoints are consistent with a nominal RBM filter setting of 0.0 seconds (reference 10.b)). The filtered setpoints are consistent with a nominal RBM filter setting $\leq$ 0.5 seconds (reference 10.a)).

The RBM setpoints in Technical Specification Table 3.3.2.1-1 are applicable when:

THERMAL POWER (% Rated)	Applicable MCPR [(1)]	Notes from Table 3.3.2.1-1	
$\geq$ 27% and < 90%	< 1.72 < 1.75	(a), (b), (f), (h) (a), (b), (f), (h)	dual loop operation single loop operation
$\geq$ 90%	< 1.47	(g)	dual loop operation [(2)]

Notes: (1) The MCPR values shown correspond to a SLMCPR of 1.08 for dual recirculation loop operation and 1.10 for single loop operation. (Ref. 1).

(2) Greater than 90% rated power is not attainable in single loop operation.

7. SHUTDOWN MARGIN (SDM) LIMIT (TECHNICAL SPECIFICATION 3.1.1)

The core shall be subcritical with the following margin with the strongest OPERABLE control rod fully withdrawn and all other OPERABLE control rods fully inserted (Ref. 8).

SDM $\geq$ 0.38% dk/k

8. REFERENCES

1. ANP-2592 Rev. 0, "Browns Ferry Unit 2 Cycle 15 Reload Analysis for 105% Original Licensed Thermal Power", dated January 2007.

2. Framatome-ANP Analytical Methodology References:
   a) XN-NF-81-58(P)(A) Revision 2 and Supplements 1 and 2, *RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model*, Exxon Nuclear Company, March 1984.
   b) XN-NF-85-67(P)(A) Revision 1, *Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel*, Exxon Nuclear Company, September 1986.
   c) EMF-85-74(P) Revision 0 Supplement 1(P)(A) and Supplement 2(P)(A), *RODEX2A (BWR) Fuel Rod Thermal-Mechanical Evaluation Model*, Siemens Power Corporation, February 1998.
   d) ANF-89-98(P)(A) Revision 1 and Supplement 1, *Generic Mechanical Design Criteria for BWR Fuel Designs*, Advanced Nuclear Fuels Corporation, May 1995.
   e) XN-NF-80-19(P)(A) Volume 1 and Supplements 1 and 2, *Exxon Nuclear Methodology for Boiling Water Reactors - Neutronic Methods for Design and Analysis*, Exxon Nuclear Company, March 1983.
   f) XN-NF-80-19(P)(A) Volume 4 Revision 1, *Exxon Nuclear Methodology for Boiling Water Reactors: Application of the ENC Methodology to BWR Reloads*, Exxon Nuclear Company, June 1986.
   g) EMF-2158(P)(A) Revision 0, *Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation of CASMO-4/MICROBURN-B2*, Siemens Power Corporation, October 1999.
   h) XN-NF-80-19(P)(A) Volume 3 Revision 2, *Exxon Nuclear Methodology for Boiling Water Reactors, THERMEX: Thermal Limits Methodology Summary Description*, Exxon Nuclear Company, January 1987.
   i) XN-NF-84-105(P)(A) Volume 1 and Volume 1 Supplements 1 and 2, *XCOBRA-T: A Computer Code for BWR Transient Thermal-Hydraulic Core Analysis*, Exxon Nuclear Company, February 1987.
   j) ANF-524(P)(A) Revision 2 and Supplements 1 and 2, *ANF Critical Power Methodology for Boiling Water Reactors*, Advanced Nuclear Fuels Corporation, November 1990.
   k) ANF-913(P)(A) Volume 1 Revision 1 and Volume 1 Supplements 2, 3 and 4, *COTRANSA2: A Computer Program for Boiling Water Reactor Transient Analyses*, Advanced Nuclear Fuels Corporation, August 1990.
   l) ANF-1358(P)(A) Revision 1, *The Loss of Feedwater Heating Transient in Boiling Water Reactors*, Advanced Nuclear Fuels Corporation, September 1992.
   m) EMF-2209(P)(A) Revision 2, *SPCB Critical Power Correlation*, Siemens Power Corporation, September 2003.
   n) EMF-2245(P)(A) Revision 0, *Application of Siemens Power Corporation's Critical Power Correlations to Co-Resident Fuel*, Siemens Power Corporation, August 2000.
   o) EMF-2361(P)(A) Revision 0, *EXEM BWR-2000 ECCS Evaluation Model*, Framatome ANP, May 2001.
   p) EMF-2292(P)(A) Revision 0, *ATRIUM™-10: Appendix K Spray Heat Transfer Coefficients*, Siemens Power Corporation, September 2000.

3. Global Nuclear Fuel Analytical Methodology References:

a) NEDE-24011-P-A-15, "General Electric Standard Application for Reactor Fuel", September 2005.
b) NEDE-24011-P-A-15-US, "General Electric Standard Application for Reactor Fuel (Supplement for United States)", September 2005.

4. 0000-0006-1355-MAPL Rev. 0, "Lattice-Dependent MAPLHGR Report for Browns Ferry Unit 2 Reload 12 Cycle 13", February 2003.

5. NEDC-32484P Rev. 6, "Browns Ferry Nuclear Plant Units 1, 2, and 3 – SAFER/GESTR-LOCA Loss-Of-Coolant Accident Analysis", dated February 2005.

6. ANP-2537P Rev. 0, "Mechanical Design Report for Browns Ferry Unit 2 Reload BFE2-15 ATRIUM™-10 Fuel Assemblies", dated May 2006.

7. GE-NE-L12-00889-00-01P Rev. 0, "GE14 Fuel Design Cycle-Independent Analyses for Browns Ferry Units 2 and 3", dated January 2002.

8. TVA-COLR-BF2C14 Rev. 1, "Browns Ferry Nuclear Plant Unit 2, Cycle 14 Core Operating Limits Report (COLR)", dated April 10, 2006.

9. EMF-3238(P) Rev. 0, "Browns Ferry Unit 2 Cycle 15 Plant Parameters Document", dated January 2006.

10. PRNM Setpoint Calculation:
   a) *Filtered Setpoints* - EDE-28-0990 Rev. 3 Supplement E, "PRNM (APRM, RBM, and RFM) Setpoint Calculations [ARTS/MELLL (NUMAC) - Power-Uprate Condition] for Tennessee Valley Authority Browns Ferry Nuclear Plant", dated October 1997.
   b) *Unfiltered Setpoints* - EDE-28-0990 Rev. 2 Supplement E, "PRNM (APRM, RBM, and RFM) Setpoint Calculations [ARTS/MELLL (NUMAC) - Power-Uprate Condition] for Tennessee Valley Authority Browns Ferry Nuclear Plant", dated October 1997.

11. GE Letter LB#: 262-97-133, "Browns Ferry Nuclear Plant Rod Block Monitor Setpoint Clarification - GE Proprietary Information", dated September 12, 1997.

12. NEDC-32433P, "Maximum Extended Load Line Limit and ARTS Improvement Program Analyses for Browns Ferry Nuclear Plant Unit 1, 2, and 3", dated April 1995.

Table 1: MCPR$_P$ Limits for BOC to NEOC Exposures – NSS Scram Times
(Applicable up to Core Average Exposure of **27,788 MWd / MTU**)

EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14	EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14
In-Service	100	1.45	1.46	**FHOOS**	100	1.48	1.50
	69	1.58	1.62		69	1.61	1.64
	63	1.61	1.64		63	1.66	1.70
	58	1.69	1.73		58	1.75	---
	58	1.78	1.78		58	1.78	1.79
	46	1.85	1.89		46	1.90	1.97
	30	2.22	2.35		30	2.33	2.49
	30 (> 50%F)	2.64	2.79		30 (> 50%F)	2.75	2.92
	25 (> 50%F)	2.89	3.08		25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.51	2.68		30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.68	2.89		25 (≤ 50%F)	2.81	3.03
RPTOOS	100	1.45	1.46	**RPTOOS FHOOS**	100	1.48	1.50
	69	1.58	1.62		69	1.61	1.64
	63	1.61	1.64		63	1.66	1.70
	58	1.69	1.73		58	1.75	---
	58	1.78	1.78		58	1.78	1.79
	46	1.85	1.89		46	1.90	1.97
	30	2.22	2.35		30	2.33	2.49
	30 (> 50%F)	2.64	2.79		30 (> 50%F)	2.75	2.92
	25 (> 50%F)	2.89	3.08		25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.51	2.68		30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.68	2.89		25 (≤ 50%F)	2.81	3.03
TBVOOS	100	1.49	1.50	**TBVOOS FHOOS**	100	1.51	1.53
	69	1.62	1.66		69	1.64	1.66
	63	1.65	1.67		63	1.68	1.72
	58	1.71	1.75		58	1.77	---
	58	1.78	1.78		58	1.78	1.81
	46	1.85	1.90		46	1.92	1.98
	30	2.23	2.36		30	2.35	2.49
	30 (> 50%F)	3.09	3.20		30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.51	3.64		25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.64	2.79		30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	2.97	3.18		25 (≤ 50%F)	3.07	3.30
RPTOOS TBVOOS	100	1.49	1.50	**RPTOOS TBVOOS FHOOS**	100	1.51	1.53
	69	1.62	1.66		69	1.64	1.66
	63	1.65	1.67		63	1.68	1.72
	58	1.71	1.75		58	1.77	---
	58	1.78	1.78		58	1.78	1.81
	46	1.85	1.90		46	1.92	1.98
	30	2.23	2.36		30	2.35	2.49
	30 (> 50%F)	3.09	3.20		30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.51	3.64		25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.64	2.79		30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	2.97	3.18		25 (≤ 50%F)	3.07	3.30

Add 0.02 to the above MCPR$_P$ limits for SLO.

Table 1 (Continued): $MCPR_P$ Limits for BOC to NEOC Exposures – NSS Scram Times
(Applicable up to Core Average Exposure of **27,788 MWd / MTU**)

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
PLUOOS	100	1.45	1.46
	69	1.58	1.62
	63	1.73	1.73
	58	---	---
	58	1.78	1.78
	46	1.85	1.89
	30	2.22	2.35
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
RPTOOS PLUOOS	100	1.45	1.46
	69	1.58	1.62
	63	1.73	1.73
	58	---	---
	58	1.78	1.78
	46	1.85	1.89
	30	2.22	2.35
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
TBVOOS PLUOOS	100	1.49	1.50
	69	1.62	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.78
	46	1.85	1.90
	30	2.23	2.36
	30 (> 50%F)	3.09	3.20
	25 (> 50%F)	3.51	3.64
	30 (≤ 50%F)	2.64	2.79
	25 (≤ 50%F)	2.97	3.18
RPTOOS TBVOOS PLUOOS	100	1.49	1.50
	69	1.62	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.78
	46	1.85	1.90
	30	2.23	2.36
	30 (> 50%F)	3.09	3.20
	25 (> 50%F)	3.51	3.64
	30 (≤ 50%F)	2.64	2.79
	25 (≤ 50%F)	2.97	3.18

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
FHOOS PLUOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.73	1.73
	58	---	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS FHOOS PLUOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.73	1.73
	58	---	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS FHOOS PLUOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30
RPTOOS TBVOOS FHOOS PLUOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30

Add 0.02 to the above $MCPR_P$ limits for SLO.

Table 2: MCPR$_P$ Limits for BOC to NEOC Exposures – TSSS Scram Times
(Applicable up to Core Average Exposure of **27,788 MWd / MTU**)

EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14	EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14
In-Service	100	1.47	1.49	FHOOS	100	1.50	1.52
	69	1.59	1.65		69	1.63	1.66
	63	1.63	1.66		63	1.68	1.72
	58	1.71	1.75		58	1.77	---
	58	1.79	1.79		58	1.79	1.81
	46	1.86	1.91		46	1.92	1.99
	30	2.23	2.37		30	2.35	2.51
	30 (> 50%F)	2.64	2.79		30 (> 50%F)	2.75	2.92
	25 (> 50%F)	2.89	3.08		25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.51	2.68		30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.68	2.89		25 (≤ 50%F)	2.81	3.03
RPTOOS	100	1.47	1.49	RPTOOS FHOOS	100	1.50	1.52
	69	1.59	1.65		69	1.63	1.66
	63	1.63	1.66		63	1.68	1.72
	58	1.71	1.75		58	1.77	---
	58	1.79	1.79		58	1.79	1.81
	46	1.86	1.91		46	1.92	1.99
	30	2.23	2.37		30	2.35	2.51
	30 (> 50%F)	2.64	2.79		30 (> 50%F)	2.75	2.92
	25 (> 50%F)	2.89	3.08		25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.51	2.68		30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.68	2.89		25 (≤ 50%F)	2.81	3.03
TBVOOS	100	1.51	1.52	TBVOOS FHOOS	100	1.53	1.55
	69	1.64	1.65		69	1.66	1.68
	63	1.66	1.69		63	1.70	1.74
	58	1.73	1.78		58	---	---
	58	1.79	1.79		58	1.79	1.83
	46	1.87	1.93		46	1.94	2.00
	30	2.25	2.39		30	2.37	2.52
	30 (> 50%F)	3.10	3.20		30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.52	3.64		25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.65	2.79		30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	2.97	3.19		25 (≤ 50%F)	3.08	3.30
RPTOOS TBVOOS	100	1.51	1.52	RPTOOS TBVOOS FHOOS	100	1.53	1.55
	69	1.64	1.65		69	1.66	1.68
	63	1.66	1.69		63	1.70	1.74
	58	1.73	1.78		58	---	---
	58	1.79	1.79		58	1.79	1.83
	46	1.87	1.93		46	1.94	2.00
	30	2.25	2.39		30	2.37	2.52
	30 (> 50%F)	3.10	3.20		30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.52	3.64		25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.65	2.79		30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	2.97	3.19		25 (≤ 50%F)	3.08	3.30

Add 0.02 to the above MCPR$_P$ limits for SLO.

Table 2 (Continued): $MCPR_P$ Limits for BOC to NEOC Exposures – TSSS Scram Times
(Applicable up to Core Average Exposure of **27,788 MWd / MTU**)

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
PLUOOS	100	1.47	1.49
	69	1.59	1.65
	63	1.74	1.74
	58	---	---
	58	1.79	1.79
	46	1.86	1.91
	30	2.23	2.37
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
RPTOOS PLUOOS	100	1.47	1.49
	69	1.59	1.65
	63	1.74	1.74
	58	---	---
	58	1.79	1.79
	46	1.86	1.91
	30	2.23	2.37
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
TBVOOS PLUOOS	100	1.51	1.52
	69	1.64	1.65
	63	1.74	1.74
	58	---	---
	58	1.79	1.79
	46	1.87	1.93
	30	2.25	2.39
	30 (> 50%F)	3.10	3.20
	25 (> 50%F)	3.52	3.64
	30 (≤ 50%F)	2.65	2.79
	25 (≤ 50%F)	2.97	3.19
RPTOOS TBVOOS PLUOOS	100	1.51	1.52
	69	1.64	1.65
	63	1.74	1.74
	58	---	---
	58	1.79	1.79
	46	1.87	1.93
	30	2.25	2.39
	30 (> 50%F)	3.10	3.20
	25 (> 50%F)	3.52	3.64
	30 (≤ 50%F)	2.65	2.79
	25 (≤ 50%F)	2.97	3.19

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
FHOOS PLUOOS	100	1.50	1.52
	69	1.63	1.66
	63	1.74	1.74
	58	---	---
	58	1.79	1.81
	46	1.92	1.99
	30	2.35	2.51
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS FHOOS PLUOOS	100	1.50	1.52
	69	1.63	1.66
	63	1.74	1.74
	58	---	---
	58	1.79	1.81
	46	1.92	1.99
	30	2.35	2.51
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS FHOOS PLUOOS	100	1.53	1.55
	69	1.66	1.68
	63	1.74	1.74
	58	---	---
	58	1.79	1.83
	46	1.94	2.00
	30	2.37	2.52
	30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.08	3.30
RPTOOS TBVOOS FHOOS PLUOOS	100	1.53	1.55
	69	1.66	1.68
	63	1.74	1.74
	58	---	---
	58	1.79	1.83
	46	1.94	2.00
	30	2.37	2.52
	30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.08	3.30

Add 0.02 to the above $MCPR_P$ limits for SLO.

Table 3: $MCPR_P$ Limits for BOC to EOC Exposures – NSS Scram Times
(Applicable up to Core Average Exposure of **31,075 MWd / MTU**)

		$MCPR_P$ Limit				$MCPR_P$ Limit	
EOOS Option	**Power (% Rated)**	**A10**	**GE14**	**EOOS Option**	**Power (% Rated)**	**A10**	**GE14**
In-Service	100	1.45	1.47	**FHOOS**	100	1.48	1.50
	69	1.58	1.62		69	1.61	1.64
	63	1.61	1.64		63	1.66	1.70
	58	1.69	1.73		58	1.75	---
	58	1.78	1.78		58	1.78	1.79
	46	1.85	1.89		46	1.90	1.97
	30	2.22	2.35		30	2.33	2.49
	30 (> 50%F)	2.64	2.79		30 (> 50%F)	2.75	2.92
	25 (> 50%F)	2.89	3.08		25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.51	2.68		30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.68	2.89		25 (≤ 50%F)	2.81	3.03
RPTOOS	100	1.45	1.47	**RPTOOS FHOOS**	100	1.48	1.50
	69	1.58	1.62		69	1.61	1.64
	63	1.61	1.64		63	1.66	1.70
	58	1.69	1.73		58	1.75	---
	58	1.78	1.78		58	1.78	1.79
	46	1.85	1.89		46	1.90	1.97
	30	2.22	2.35		30	2.33	2.49
	30 (> 50%F)	2.64	2.79		30 (> 50%F)	2.75	2.92
	25 (> 50%F)	2.89	3.08		25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.51	2.68		30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.68	2.89		25 (≤ 50%F)	2.81	3.03
TBVOOS	100	1.49	1.51	**TBVOOS FHOOS**	100	1.51	1.53
	69	1.62	1.66		69	1.64	1.66
	63	1.65	1.67		63	1.68	1.72
	58	1.71	1.75		58	1.77	---
	58	1.78	1.78		58	1.78	1.81
	46	1.85	1.90		46	1.92	1.98
	30	2.23	2.36		30	2.35	2.49
	30 (> 50%F)	3.09	3.20		30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.51	3.64		25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.64	2.79		30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	2.97	3.18		25 (≤ 50%F)	3.07	3.30
RPTOOS TBVOOS	100	1.49	1.51	**RPTOOS TBVOOS FHOOS**	100	1.51	1.53
	69	1.62	1.66		69	1.64	1.66
	63	1.65	1.67		63	1.68	1.72
	58	1.71	1.75		58	1.77	---
	58	1.78	1.78		58	1.78	1.81
	46	1.85	1.90		46	1.92	1.98
	30	2.23	2.36		30	2.35	2.49
	30 (> 50%F)	3.09	3.20		30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.51	3.64		25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.64	2.79		30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	2.97	3.18		25 (≤ 50%F)	3.07	3.30

Add 0.02 to the above $MCPR_P$ limits for SLO.

Table 3 (Continued): $MCPR_P$ Limits for BOC to EOC Exposures – NSS Scram Times

(Applicable up to Core Average Exposure of **31,075 MWd / MTU**)

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
PLUOOS	100	1.45	1.47
	69	1.58	1.62
	63	1.73	1.73
	58	---	---
	58	1.78	1.78
	46	1.85	1.89
	30	2.22	2.35
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
RPTOOS PLUOOS	100	1.45	1.47
	69	1.58	1.62
	63	1.73	1.73
	58	---	---
	58	1.78	1.78
	46	1.85	1.89
	30	2.22	2.35
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
TBVOOS PLUOOS	100	1.49	1.51
	69	1.62	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.78
	46	1.85	1.90
	30	2.23	2.36
	30 (> 50%F)	3.09	3.20
	25 (> 50%F)	3.51	3.64
	30 (≤ 50%F)	2.64	2.79
	25 (≤ 50%F)	2.97	3.18
RPTOOS TBVOOS PLUOOS	100	1.49	1.51
	69	1.62	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.78
	46	1.85	1.90
	30	2.23	2.36
	30 (> 50%F)	3.09	3.20
	25 (> 50%F)	3.51	3.64
	30 (≤ 50%F)	2.64	2.79
	25 (≤ 50%F)	2.97	3.18

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
FHOOS PLUOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.73	1.73
	58	---	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS FHOOS PLUOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.73	1.73
	58	---	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS FHOOS PLUOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30
RPTOOS TBVOOS FHOOS PLUOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30

Add 0.02 to the above $MCPR_P$ limits for SLO.

Table 4: $MCPR_P$ Limits for BOC to EOC Exposures – TSSS Scram Times

(Applicable up to Core Average Exposure of **31,075 MWd / MTU**)

EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14	EOOS Option	Power (% Rated)	$MCPR_P$ Limit A10	$MCPR_P$ Limit GE14
In-Service	100	1.47	1.49	**FHOOS**	100	1.50	1.52
	69	1.59	1.65		69	1.63	1.66
	63	1.63	1.66		63	1.68	1.72
	58	1.71	1.75		58	1.77	---
	58	1.79	1.79		58	1.79	1.81
	46	1.86	1.91		46	1.92	1.99
	30	2.23	2.37		30	2.35	2.51
	30 (> 50%F)	2.64	2.79		30 (> 50%F)	2.75	2.92
	25 (> 50%F)	2.89	3.08		25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.51	2.68		30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.68	2.89		25 (≤ 50%F)	2.81	3.03
RPTOOS	100	1.47	1.50	**RPTOOS FHOOS**	100	1.50	1.52
	69	1.59	1.65		69	1.63	1.66
	63	1.63	1.66		63	1.68	1.72
	58	1.71	1.75		58	1.77	---
	58	1.79	1.79		58	1.79	1.81
	46	1.86	1.91		46	1.92	1.99
	30	2.23	2.37		30	2.35	2.51
	30 (> 50%F)	2.64	2.79		30 (> 50%F)	2.75	2.92
	25 (> 50%F)	2.89	3.08		25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.51	2.68		30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.68	2.89		25 (≤ 50%F)	2.81	3.03
TBVOOS	100	1.51	1.52	**TBVOOS FHOOS**	100	1.53	1.55
	69	1.64	1.65		69	1.66	1.68
	63	1.66	1.69		63	1.70	1.74
	58	1.73	1.78		58	---	---
	58	1.79	1.79		58	1.79	1.83
	46	1.87	1.93		46	1.94	2.00
	30	2.25	2.39		30	2.37	2.52
	30 (> 50%F)	3.10	3.20		30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.52	3.64		25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.65	2.79		30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	2.97	3.19		25 (≤ 50%F)	3.08	3.30
RPTOOS TBVOOS	100	1.52	1.53	**RPTOOS TBVOOS FHOOS**	100	1.53	1.55
	69	1.64	1.65		69	1.66	1.68
	63	1.66	1.69		63	1.70	1.74
	58	1.73	1.78		58	---	---
	58	1.79	1.79		58	1.79	1.83
	46	1.87	1.93		46	1.94	2.00
	30	2.25	2.39		30	2.37	2.52
	30 (> 50%F)	3.10	3.20		30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.52	3.64		25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.65	2.79		30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	2.97	3.19		25 (≤ 50%F)	3.08	3.30

Add 0.02 to the above $MCPR_P$ limits for SLO.

Table 4 (Continued): MCPR$_P$ Limits for BOC to EOC Exposures – TSSS Scram Times
(Applicable up to Core Average Exposure of **31,075 MWd / MTU**)

EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14
PLUOOS	100	1.47	1.49
	69	1.59	1.65
	63	1.74	1.74
	58	---	---
	58	1.79	1.79
	46	1.86	1.91
	30	2.23	2.37
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
RPTOOS PLUOOS	100	1.47	1.50
	69	1.59	1.65
	63	1.74	1.74
	58	---	---
	58	1.79	1.79
	46	1.86	1.91
	30	2.23	2.37
	30 (> 50%F)	2.64	2.79
	25 (> 50%F)	2.89	3.08
	30 (≤ 50%F)	2.51	2.68
	25 (≤ 50%F)	2.68	2.89
TBVOOS PLUOOS	100	1.51	1.52
	69	1.64	1.65
	63	1.74	1.74
	58	---	---
	58	1.79	1.79
	46	1.87	1.93
	30	2.25	2.39
	30 (> 50%F)	3.10	3.20
	25 (> 50%F)	3.52	3.64
	30 (≤ 50%F)	2.65	2.79
	25 (≤ 50%F)	2.97	3.19
RPTOOS TBVOOS PLUOOS	100	1.52	1.53
	69	1.64	1.65
	63	1.74	1.74
	58	---	---
	58	1.79	1.79
	46	1.87	1.93
	30	2.25	2.39
	30 (> 50%F)	3.10	3.20
	25 (> 50%F)	3.52	3.64
	30 (≤ 50%F)	2.65	2.79
	25 (≤ 50%F)	2.97	3.19

EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14
FHOOS PLUOOS	100	1.50	1.52
	69	1.63	1.66
	63	1.74	1.74
	58	---	---
	58	1.79	1.81
	46	1.92	1.99
	30	2.35	2.51
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS FHOOS PLUOOS	100	1.50	1.52
	69	1.63	1.66
	63	1.74	1.74
	58	---	---
	58	1.79	1.81
	46	1.92	1.99
	30	2.35	2.51
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS FHOOS PLUOOS	100	1.53	1.55
	69	1.66	1.68
	63	1.74	1.74
	58	---	---
	58	1.79	1.83
	46	1.94	2.00
	30	2.37	2.52
	30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.08	3.30
RPTOOS TBVOOS FHOOS PLUOOS	100	1.53	1.55
	69	1.66	1.68
	63	1.74	1.74
	58	---	---
	58	1.79	1.83
	46	1.94	2.00
	30	2.37	2.52
	30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.08	3.30

Add 0.02 to the above MCPR$_P$ limits for SLO.

Table 5: MCPR$_P$ Limits for BOC to CD Exposures – NSS Scram Times

(Applicable up to Core Average Exposure of **32,274 MWd / MTU**)

All Values Include FFTR/FHOOS and Bound Heaters In-Service

EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14
In-Service	100	1.48	1.50
	69	1.61	1.64
	63	1.66	1.70
	58	1.75	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.66	1.70
	58	1.75	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.68	1.72
	58	1.77	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30
RPTOOS TBVOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.68	1.72
	58	1.77	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30

EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14
PLUOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.73	1.73
	58	---	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS PLUOOS	100	1.48	1.50
	69	1.61	1.64
	63	1.73	1.73
	58	---	---
	58	1.78	1.79
	46	1.90	1.97
	30	2.33	2.49
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS PLUOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30
RPTOOS TBVOOS PLUOOS	100	1.51	1.53
	69	1.64	1.66
	63	1.73	1.73
	58	---	---
	58	1.78	1.81
	46	1.92	1.98
	30	2.35	2.49
	30 (> 50%F)	3.19	3.31
	25 (> 50%F)	3.62	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.07	3.30

Add 0.02 to the above MCPR$_P$ limits for SLO.

Table 6: MCPR$_P$ Limits for BOC to CD Exposures – TSSS Scram Times

(Applicable up to Core Average Exposure of **32,274 MWd / MTU**)

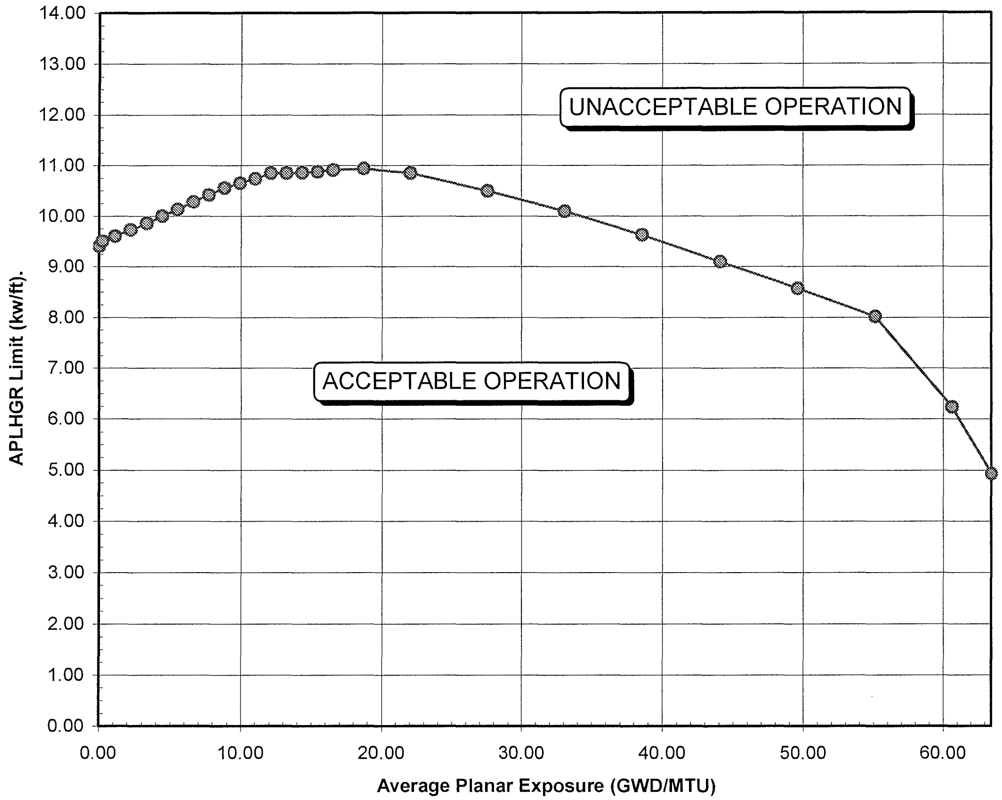
All Values Include FFTR/FHOOS and Bound Heaters In-Service

EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14
In-Service	100	1.50	1.52
	69	1.63	1.66
	63	1.68	1.72
	58	1.77	---
	58	1.79	1.81
	46	1.92	1.99
	30	2.35	2.51
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS	100	1.50	1.52
	69	1.63	1.66
	63	1.68	1.72
	58	1.77	---
	58	1.79	1.81
	46	1.92	1.99
	30	2.35	2.51
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS	100	1.53	1.55
	69	1.66	1.68
	63	1.70	1.74
	58	---	---
	58	1.79	1.83
	46	1.94	2.00
	30	2.37	2.52
	30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.08	3.30
RPTOOS TBVOOS	100	1.54	1.55
	69	1.66	1.68
	63	1.70	1.74
	58	---	---
	58	1.79	1.83
	46	1.94	2.00
	30	2.37	2.52
	30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.08	3.30

EOOS Option	Power (% Rated)	MCPR$_P$ Limit A10	MCPR$_P$ Limit GE14
PLUOOS	100	1.50	1.52
	69	1.63	1.66
	63	1.74	1.74
	58	---	---
	58	1.79	1.81
	46	1.92	1.99
	30	2.35	2.51
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
RPTOOS PLUOOS	100	1.50	1.53
	69	1.63	1.66
	63	1.74	1.74
	58	---	---
	58	1.79	1.81
	46	1.92	1.99
	30	2.35	2.51
	30 (> 50%F)	2.75	2.92
	25 (> 50%F)	3.03	3.24
	30 (≤ 50%F)	2.60	2.79
	25 (≤ 50%F)	2.81	3.03
TBVOOS PLUOOS	100	1.53	1.55
	69	1.66	1.68
	63	1.74	1.74
	58	---	---
	58	1.79	1.83
	46	1.94	2.00
	30	2.37	2.52
	30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.08	3.30
RPTOOS TBVOOS PLUOOS	100	1.54	1.55
	69	1.66	1.68
	63	1.74	1.74
	58	---	---
	58	1.79	1.83
	46	1.94	2.00
	30	2.37	2.52
	30 (> 50%F)	3.20	3.31
	25 (> 50%F)	3.63	3.78
	30 (≤ 50%F)	2.72	2.88
	25 (≤ 50%F)	3.08	3.30

Add 0.02 to the above MCPR$_P$ limits for SLO.

Figure 1
APLHGR Limits for Bundle Type GE14-P10DNAB416-16GZ
(GE14 EDB#2600)



Most Limiting Lattice
for Each Exposure Point

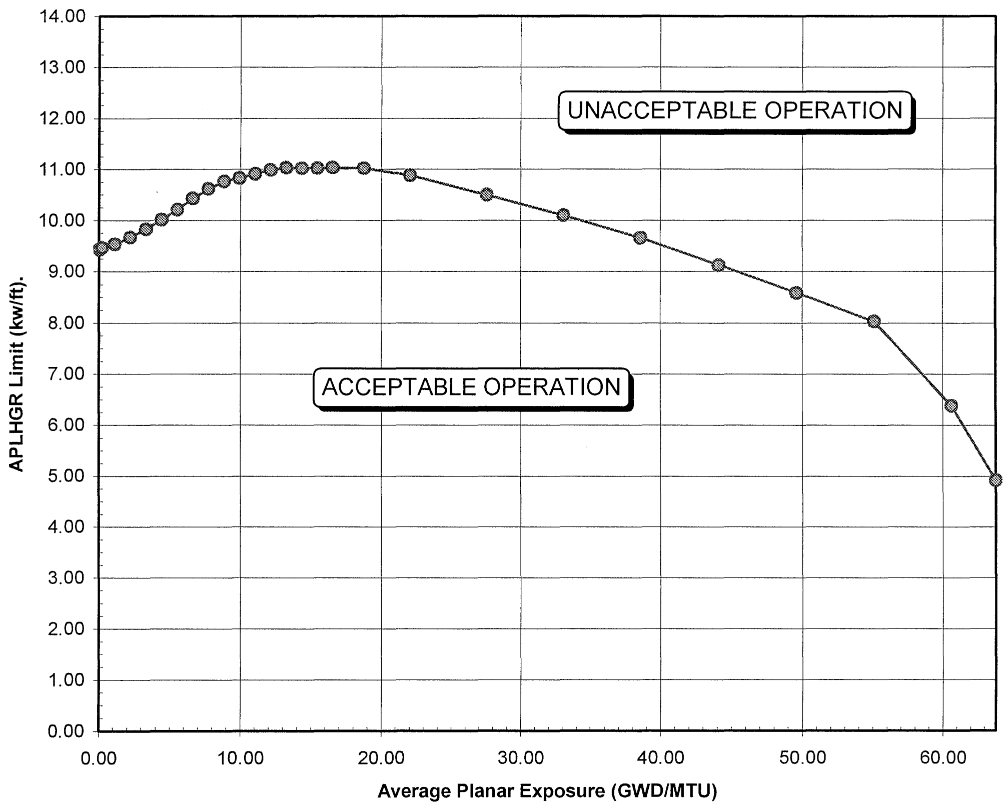
Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)	Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)	Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)
0.00	9.41	8.82	10.56	22.05	10.85
0.22	9.51	9.92	10.65	27.56	10.50
1.10	9.61	11.02	10.74	33.07	10.10
2.20	9.73	12.13	10.85	38.58	9.63
3.31	9.86	13.23	10.85	44.09	9.10
4.41	10.00	14.33	10.86	49.60	8.57
5.51	10.14	15.43	10.88	55.12	8.02
6.61	10.28	16.53	10.91	60.63	6.24
7.72	10.42	18.74	10.94	63.50	4.93

These values apply to both Turbine Bypass In-Service and Out-Of-Service.

These values apply to both Recirculation Pump Trip In-Service and Out-Of-Service.

These limits are for dual recirculation loop operation. Single Loop Operation (SLO) adjustments are performed as described in Section 2

Figure 2
APLHGR Limits for Bundle Type GE14-P10DNAB416-16GZ
(GE14 EDB#2601)



Most Limiting Lattice
for Each Exposure Point

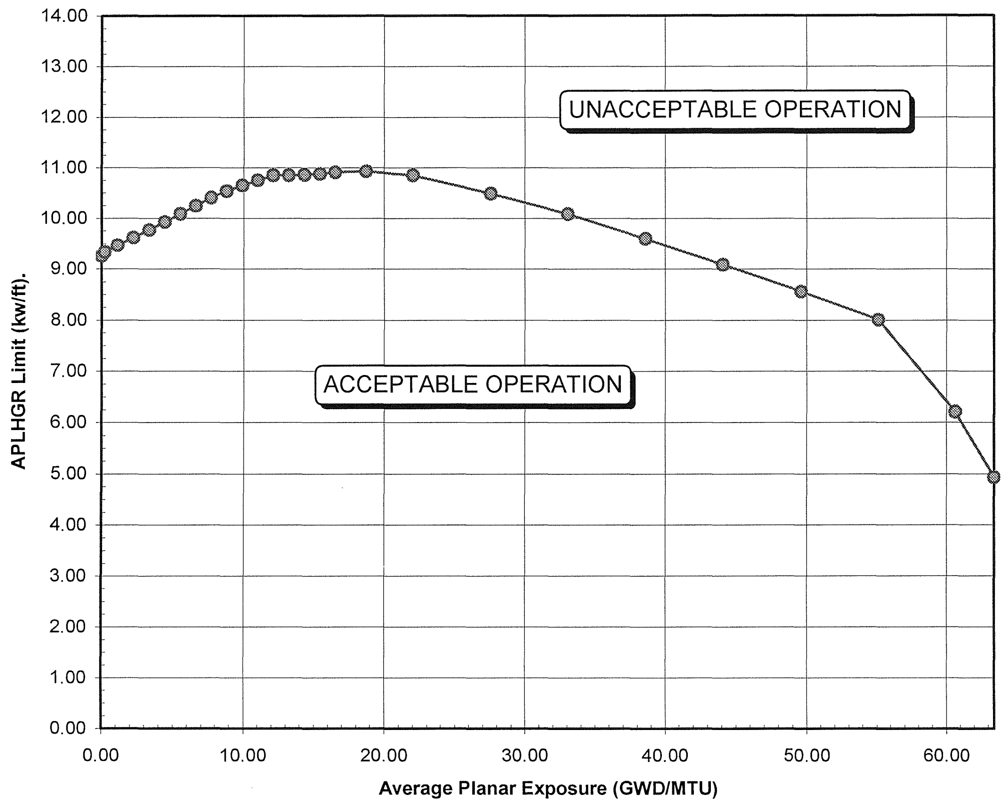
Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)	Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)	Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)
0.00	9.43	8.82	10.76	22.05	10.88
0.22	9.47	9.92	10.83	27.56	10.50
1.10	9.54	11.02	10.91	33.07	10.10
2.20	9.67	12.13	10.99	38.58	9.66
3.31	9.83	13.23	11.03	44.09	9.13
4.41	10.02	14.33	11.02	49.60	8.59
5.51	10.21	15.43	11.02	55.12	8.03
6.61	10.43	16.53	11.03	60.63	6.38
7.72	10.62	18.74	11.02	63.82	4.92

These values apply to both Turbine Bypass In-Service and Out-Of-Service.

These values apply to both Recirculation Pump Trip In-Service and Out-Of-Service.

These limits are for dual recirculation loop operation. Single Loop Operation (SLO) adjustments are performed as described in Section 2

Figure 3
APLHGR Limits for Bundle Type GE14-P10DNAB416-18GZ
(GE14 EDB# 2627)



Most Limiting Lattice
for Each Exposure Point

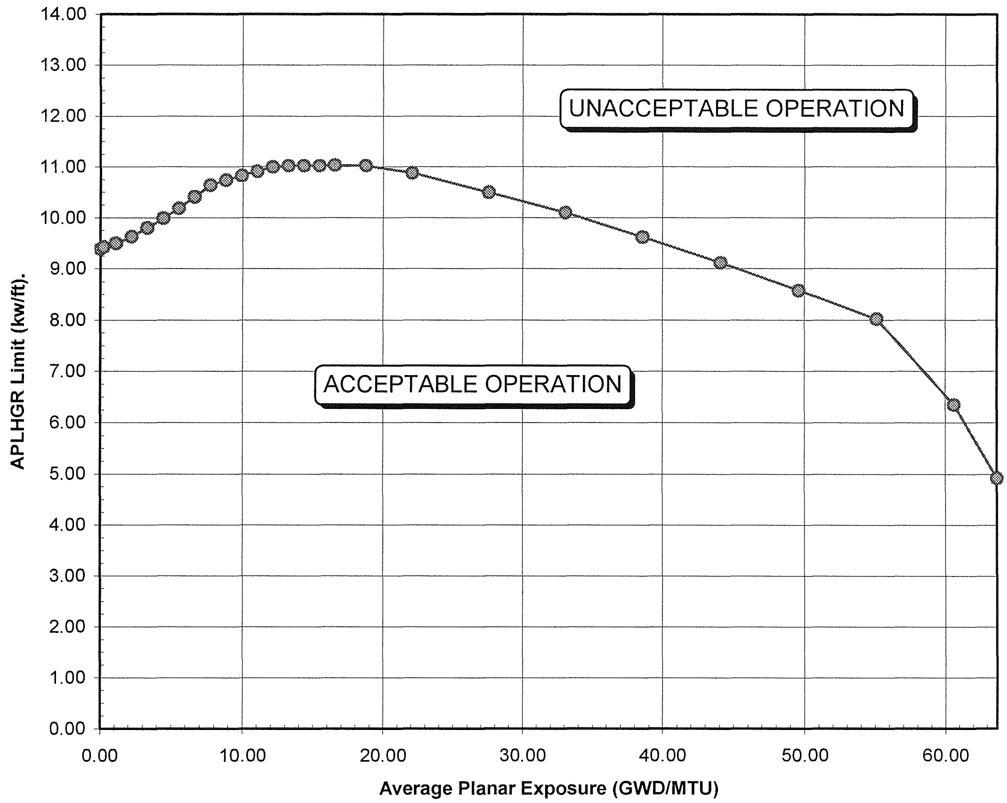
Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)	Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)	Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)
0.00	9.26	8.82	10.54	22.05	10.85
0.22	9.34	9.92	10.65	27.56	10.49
1.10	9.47	11.02	10.75	33.07	10.09
2.20	9.62	12.13	10.85	38.58	9.60
3.31	9.77	13.23	10.85	44.09	9.09
4.41	9.93	14.33	10.86	49.60	8.56
5.51	10.09	15.43	10.88	55.12	8.01
6.61	10.25	16.53	10.91	60.63	6.21
7.72	10.41	18.74	10.93	63.42	4.93

These values apply to both Turbine Bypass In-Service and Out-Of-Service.

These values apply to both Recirculation Pump Trip In-Service and Out-Of-Service.

These limits are for dual recirculation loop operation. Single Loop Operation (SLO) adjustments are performed as described in Section 2

Figure 4
APLHGR Limits for Bundle Type GE14-P10DNAB417-18GZ
(GE14 EDB# 2628)



Most Limiting Lattice
for Each Exposure Point

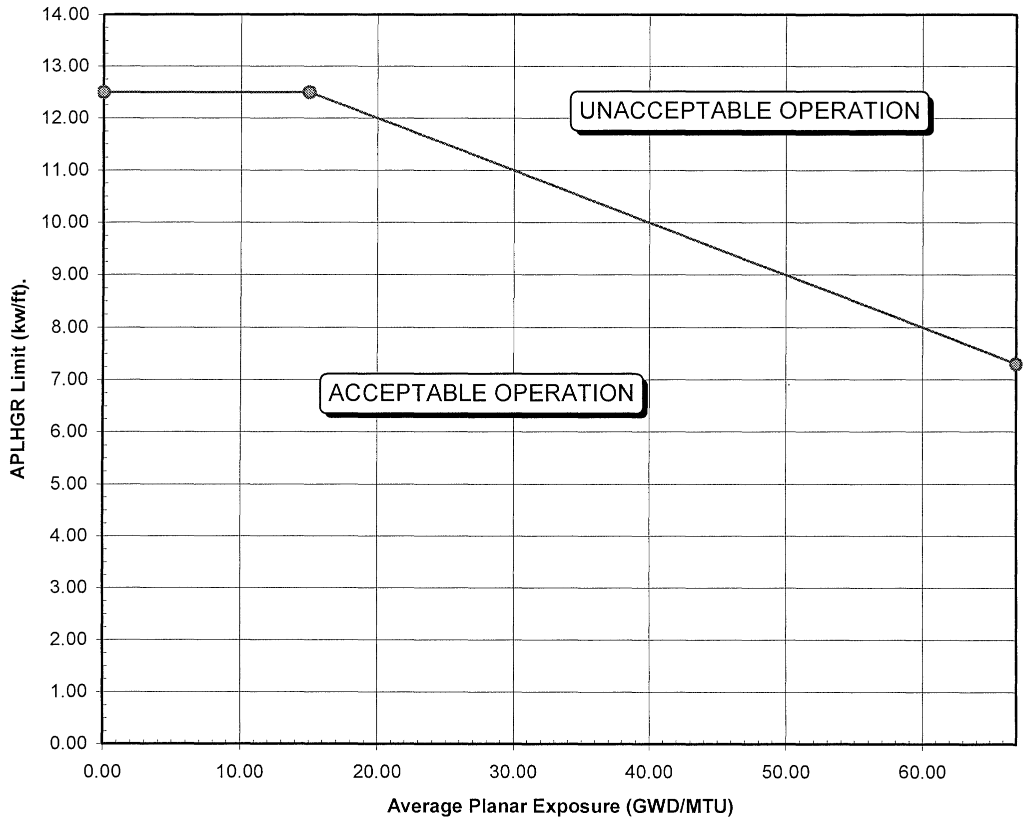
Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)	Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)	Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)
0.00	9.39	8.82	10.74	22.05	10.88
0.22	9.43	9.92	10.83	27.56	10.50
1.10	9.50	11.02	10.91	33.07	10.10
2.20	9.63	12.13	11.00	38.58	9.62
3.31	9.80	13.23	11.02	44.09	9.12
4.41	9.99	14.33	11.02	49.60	8.58
5.51	10.19	15.43	11.02	55.12	8.02
6.61	10.41	16.53	11.03	60.63	6.35
7.72	10.64	18.74	11.02	63.74	4.92

These values apply to both Turbine Bypass In-Service and Out-Of-Service.

These values apply to both Recirculation Pump Trip In-Service and Out-Of-Service.

These limits are for dual recirculation loop operation. Single Loop Operation (SLO) adjustments are performed as described in Section 2

Figure 5
APLHGR Limits for all ATRIUM-10™ Fuel
(A10)



Average Planar Exposure (GWD/MTU)	LHGR Limit (kw/ft)
0.00	12.50
15.00	12.50
67.00	7.30

These values apply to both Turbine Bypass In-Service and Out-Of-Service.

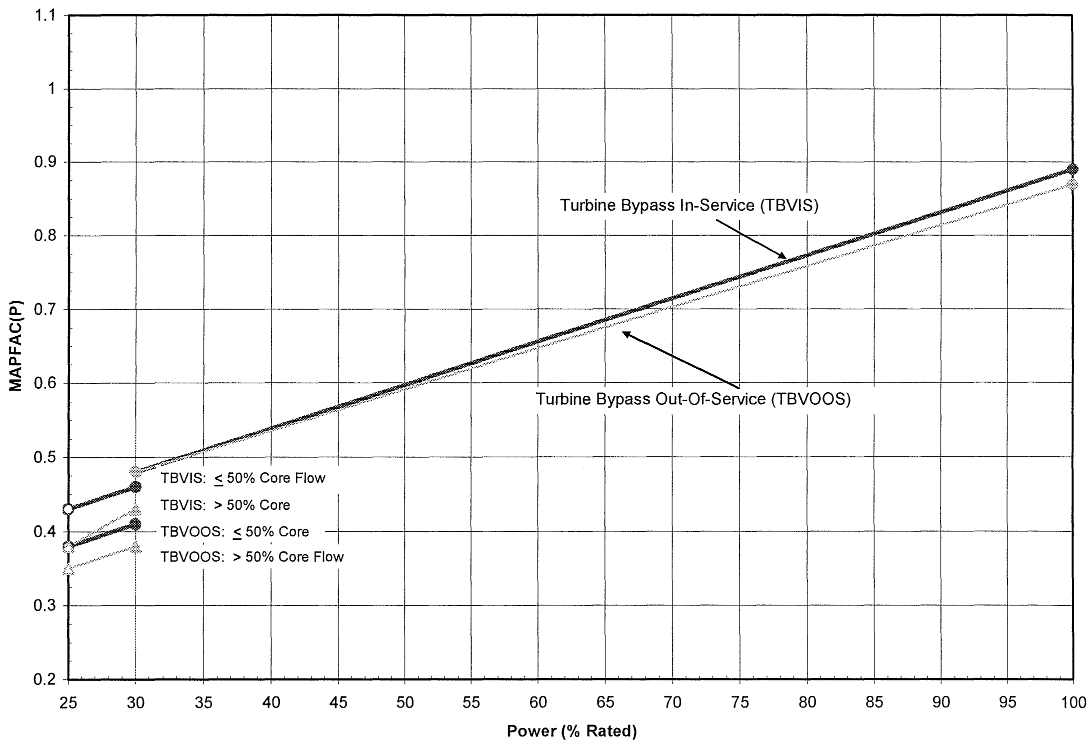
These values apply to both Recirculation Pump Trip In-Service and Out-Of-Service.

These limits are for dual recirculation loop operation. Single Loop Operation (SLO) adjustments are performed as described in Section 2

Figure 6

GE14 Power Dependent MAPLHGR Multiplier - MAPFAC(P)

NSS/TSSS Insertion Times - All Exposures



Turbine Bypass In-Service

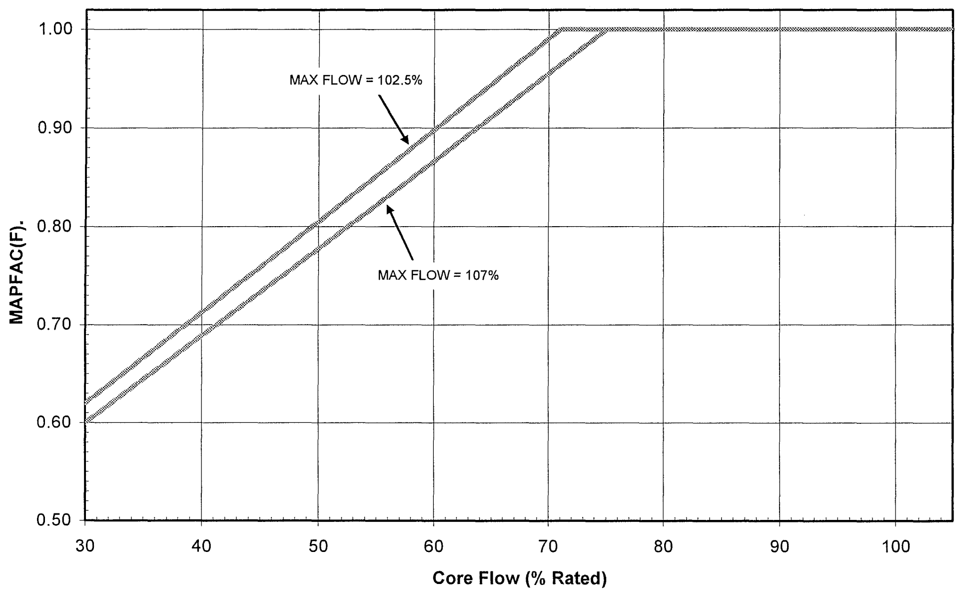
Core Power (% rated)	MAPFAC(P)
100	0.89
30	0.48
Core Flow > 50% rated	
30	0.41
25	0.38
Core Flow ≤ 50% rated	
30	0.46
25	0.43

Turbine Bypass Out-Of-Service

Core Power (% rated)	MAPFAC(P)
100	0.87
30	0.48
Core Flow > 50% rated	
30	0.38
25	0.35
Core Flow ≤ 50% rated	
30	0.43
25	0.38

MAPFAC(P) is not dependent upon any Equipment Out-Of-Service except Turbine Bypass.

Figure 7
Flow Dependent MAPLHGR Factor - MAPFAC(F)
(GE14)



Max Core Flow 102.5% Rated

Core Flow (% rated)	MAPFAC(F)
30	0.62
71	1.00
102.5	1.00

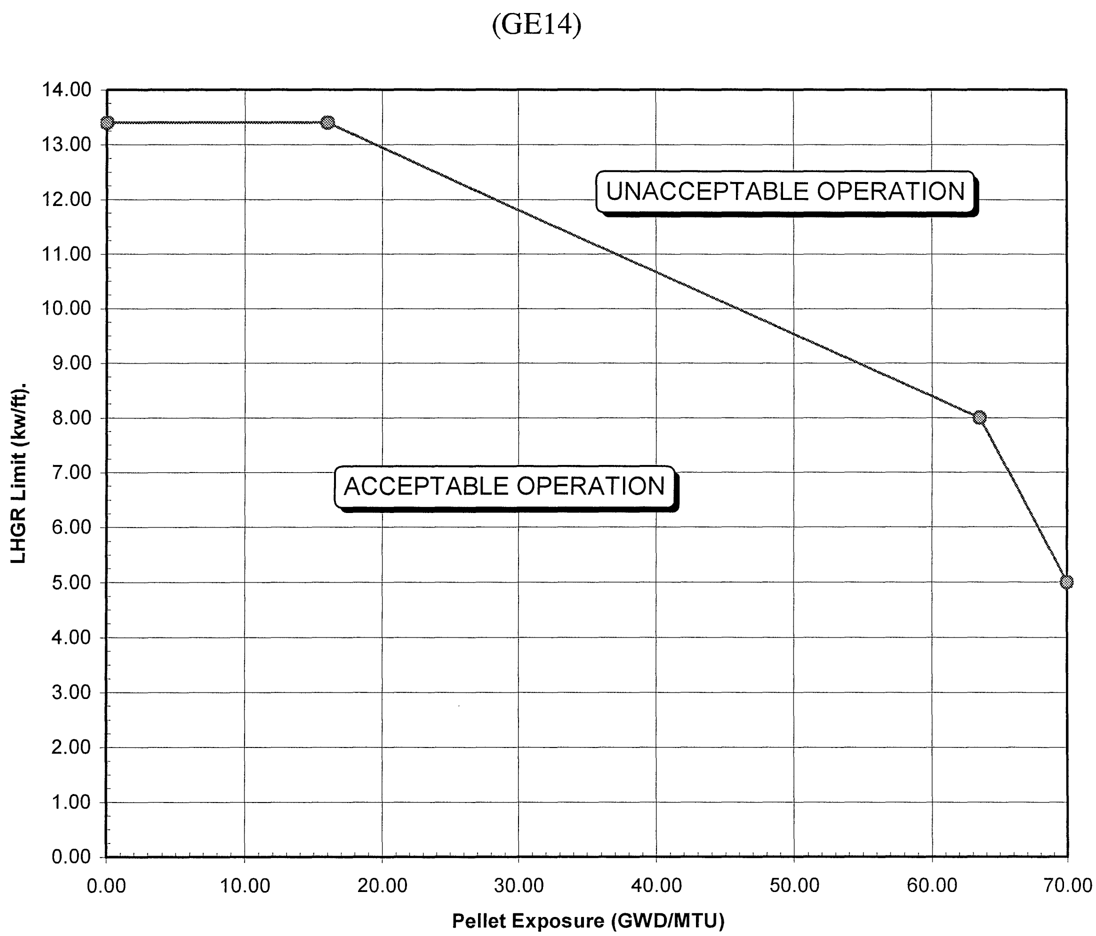
Max Core Flow 107% Rated

Core Flow (% rated)	MAPFAC(F)
30	0.60
75	1.00
107	1.00

These values bound both Turbine Bypass In-Service and Out-Of-Service.
These values bound both Recirculation Pump Trip In-Service and Out-Of-Service.

The 102.5% maximum flow line is used for operation up to 100% rated flow.
The 107% maximum flow line is used for operation up to 105% rated flow (ICF).

Figure 8
LHGR Limits for all GE-14 Fuel

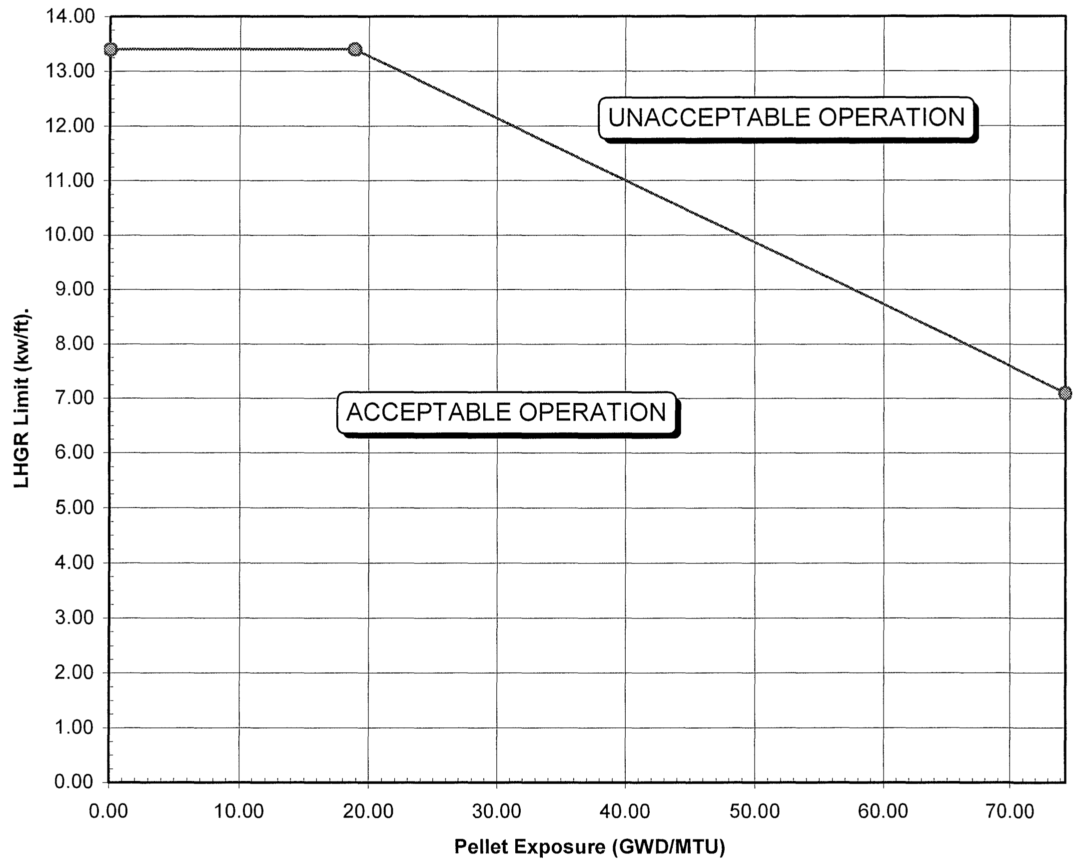


Pellet Exposure (GWD/MTU)	LHGR Limit (kw/ft)
0.00	13.40
16.00	13.40
63.50	8.00
70.00	5.00

These values apply to both Turbine Bypass In-Service and Out-Of-Service.
These values apply to both Recirculation Pump Trip In-Service and Out-Of-Service.
These limits apply to both Two Loop Operation (TLO) and Single Loop Operation (SLO).

Figure 9
LHGR Limits for all ATRIUM-10 Fuel

(A10)



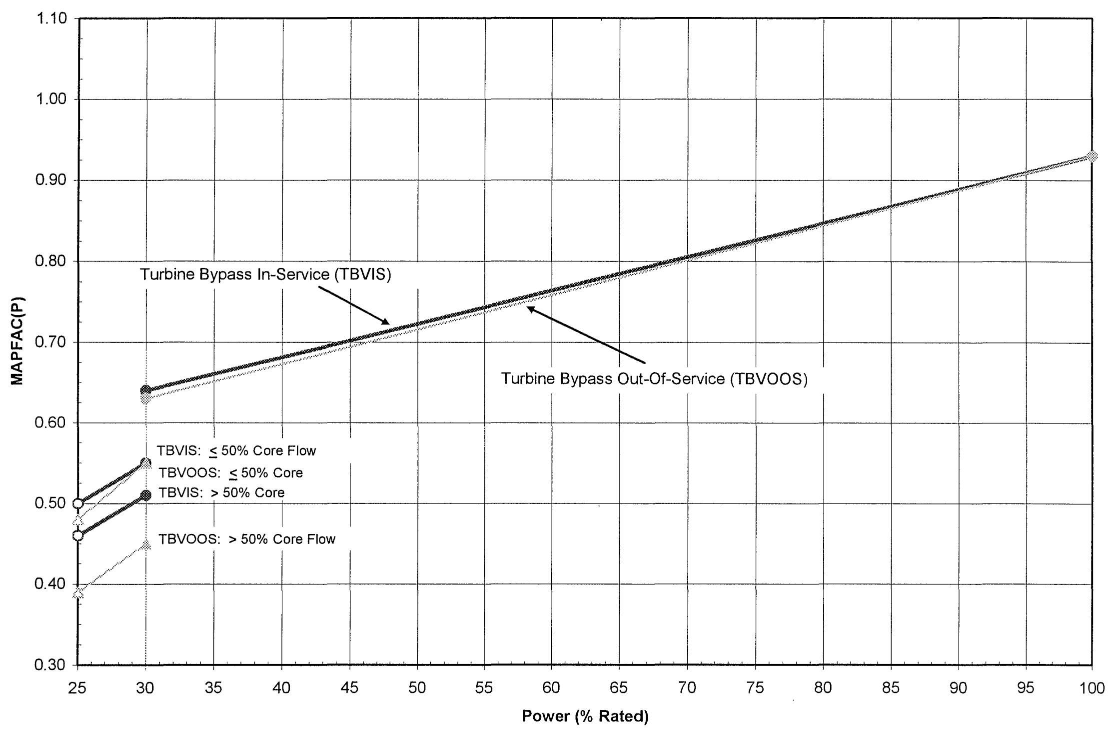
Pellet Exposure (GWD/MTU)	LHGR Limit (kw/ft)
0.00	13.40
18.90	13.40
74.40	7.10

These values apply to both Turbine Bypass In-Service and Out-Of-Service.

These values apply to both Recirculation Pump Trip In-Service and Out-Of-Service.

These limits apply to both Two Loop Operation (TLO) and Single Loop Operation (SLO).

Figure 10
A10 Power Dependent LHGR Multiplier - LHGRFAC(P)
NSS/TSSS Insertion Times - All Exposures



Turbine Bypass In-Service

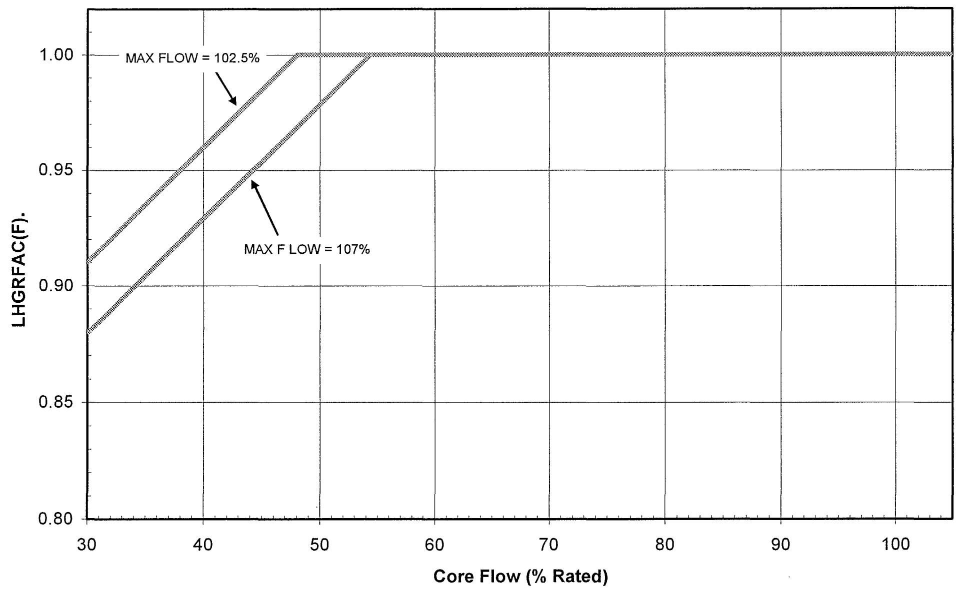
Core Power (% rated)	LHGRFAC(P)
100	0.93
30	0.64
Core Flow > 50% rated	
30	0.51
25	0.46
Core Flow ≤ 50% rated	
30	0.55
25	0.50

Turbine Bypass Out-Of-Service

Core Power (% rated)	LHGRFAC(P)
100	0.93
30	0.63
Core Flow > 50% rated	
30	0.45
25	0.39
Core Flow ≤ 50% rated	
30	0.55
25	0.48

LHGRFAC(P) is not dependent upon any Equipment Out-Of-Service except Turbine Bypass.

Figure 11
Flow Dependent LHGR Multiplier - LHGRFAC(F)
(A10 Fuel)



Max Core Flow 102.5% Rated

Core Flow (% rated)	LHGRFAC(F)
30	0.91
48	1.00
102.5	1.00

Max Core Flow 107% Rated

Core Flow (% rated)	LHGRFAC(F)
30	0.88
54.4	1.00
107	1.00

These values bound both Turbine Bypass In-Service and Out-Of-Service.
These values bound both Recirculation Pump Trip In-Service and Out-Of-Service.

The 102.5% maximum flow line is used for operation up to 100% rated flow.
The 107% maximum flow line is used for operation up to 105% rated flow (ICF).

Proposed Answer: **A**

Explanation:

a. Correct answer.

b. Part (1) is correct. The second 12 hour shift did not count due to the absence for two hours for FFD testing. Part (2) is incorrect. Although 4 hours will yield the required 40 hours of 10CFR 50, OPDP-10 Appendix E 4.0.A.3 requires the same number of complete shifts for activating a license as that required to maintain a license.

c. Part (1) is incorrect. OPDP-10 does not allow credit for absences from shift that exceed a few minutes in duration. Although only two additional hours may meet the total requirement, credit for a shift must extend from turnover to turnover. Therefore, to comply with OPDP-10 Appendix C step 4.0.E Table, three additional shifts are required. Part (2) is correct. Although only 4 hours are required to achieve 40 hours total, Appendix E 4.0.A.3 requires five total shifts to ensure the 40 hour requirement has been met.

d. Part (1) is incorrect as stated in (c) above. Part (2) is incorrect as stated in (b) above.

Examination Outline Cross-reference:	Level	RO	SRO
256000G2.2.44	Tier #		2
Ability to interpret control room indications to verify the status and operation of a system, and understand how operator actions and directives affect plant and system conditions. Reactor Condensate	Group #		2
	K/A #	256000G2.2.44	
	Importance Rating	4.2	4.4

Proposed Question: **SRO #18**

A seismic event has resulted in the following Unit-2 plant conditions:

- All control rods are inserted.
- RPV level is (-) 125 inches and lowering slowly.
- RPV pressure is 450 psig with a cooldown in progress at $\leq$90 ^{O}F/hr.
- RHR Loop II is lined up for Drywell Spray.
- All other ECCS systems are unavailable.
- Drywell pressure is 4.8 psig and lowering.
- ADS has been inhibited in accordance with 2-EOI-1, "RPV Control" step RC/L-7.

Which ONE of the following describes the required actions to mitigate this event?

A. Enter 2-EOI-C1, "Alternate Level Control" and direct performance of 2-EOI-Appendix 6A, "Injection Subsystems Lineup Condensate."

B. Enter 2-EOI-C1, "Alternate Level Control" and direct performance of 2-EOI-Appendix 5A, "Injection System Lineup Condensate/Feedwater."

C. Enter 2-EOI-C2, "Emergency Depressurization" and direct performance of 2-EOI-Appendix 6A, "Injection Subsystems Lineup Condensate."

D. Enter 2-EOI-C2, "Emergency Depressurization" and direct performance of 2-EOI-Appendix 5A, "Injection System Lineup Condensate/Feedwater."

Proposed Answer: **A**

Explanation:

a. Correct answer.

b. Part (1) is correct. Part (2) is incorrect. Appendix 5A is a lineup for injection with RFPs which require MSIVs open. With RPV level below -122 inches, the MSIVs are closed. In addition, given all rods are in, performance of EOI Appendix 8A to bypass the MSIV low water level isolation is not appropriate.

c. Part (1) is incorrect. Direction to perform Emergency Depressurization based on reactor water level is given from EOI-C1 when RPV level drops below -162 inches. Other conditions given in the stem do not require Emergency Depressurization since Drywell Sprays have been initiated and appear to be effective. Part (2) is correct.

d. Part (1) is incorrect as stated in (c) above. Part (2) is incorrect as stated in (b) above.

Technical Reference(s):	2-EOI-1, "RPV Control", 2-EOI-App 5A	(Attach if not previously provided)
	2-EOI-C1, Alt Lvl Control", 2-EOI-App 6A	

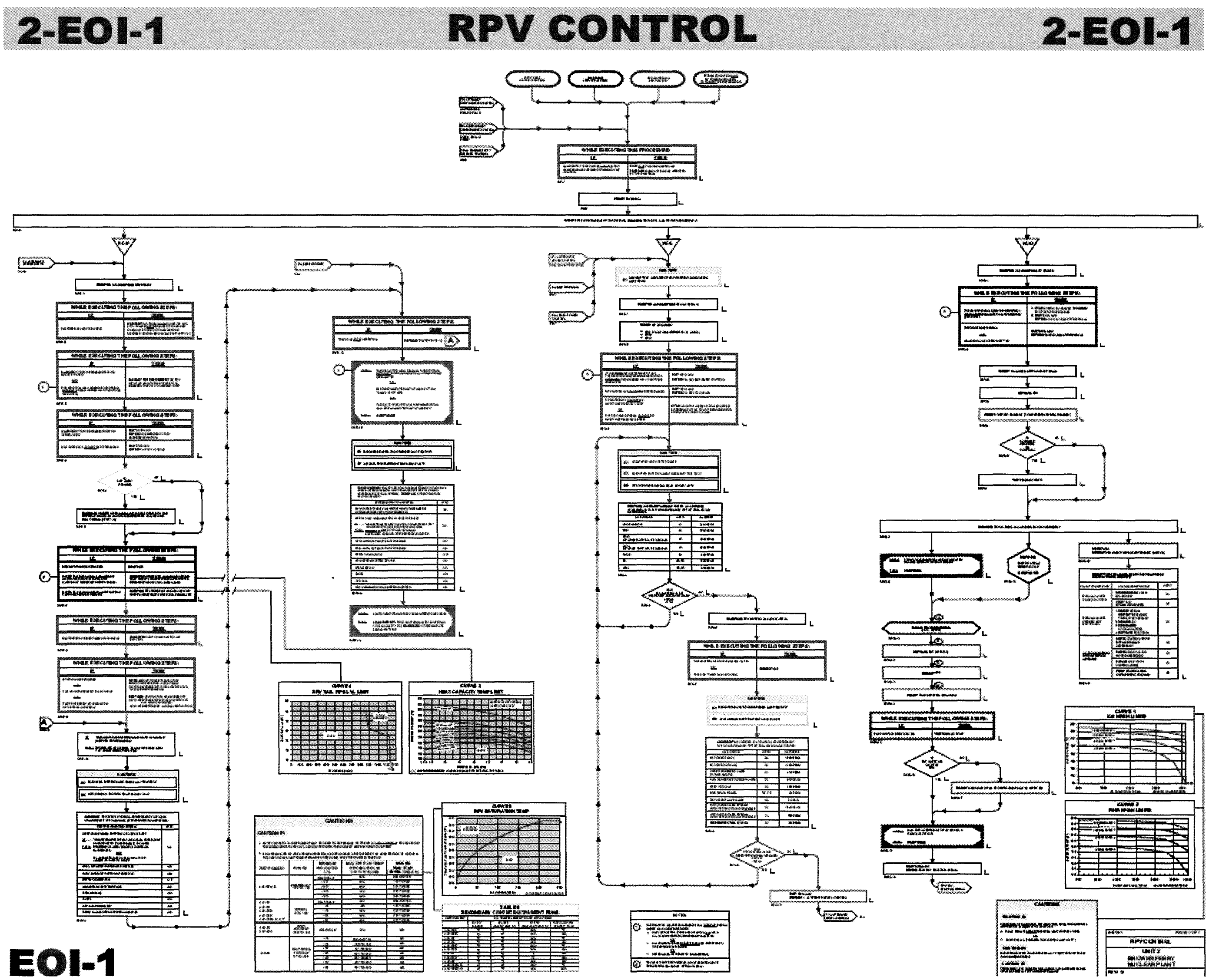
Proposed references to be provided to applicants during examination: None

Question Source:	Bank #		
	Modified Bank #		(Note changes or attach parent)
	New	7/18/2008 RMS	
Question History:	Last NRC Exam		

Question Cognitive Level:	Memory or Fundamental Knowledge	
	Comprehension or Analysis	X

10 CFR Part 55 Content:	55.41	
	55.43	X

Comments: This question is provided without reference to the EOI flowchart. As such, the candidate must utilize available indications and apply knowledge of the EOI mitigation strategy to determine the correct answer.


2-EOI-1
RPV CONTROL
2-EOI-1
EOI-1

5. **VERIFY OPEN** the following heater isolation valves:

   - 2-FCV-3-38, HP HTR 2A2 FW INLET ISOL VLV ____
   - 2-FCV-3-31, HP HTR 2B2 FW INLET ISOL VLV ____
   - 2-FCV-3-24, HP HTR 2C2 FW INLET ISOL VLV ____
   - 2-FCV-3-75, HP HTR 2A1 FW OUTLET ISOL VLV ____
   - 2-FCV-3-76, HP HTR 2B1 FW OUTLET ISOL VLV ____
   - 2-FCV-3-77, HP HTR 2C1 FW OUTLET ISOL VLV. ____

6. **VERIFY OPEN** the following RFP suction valves:

   - 2-FCV-2-83, RFP 2A SUCTION VALVE ____
   - 2-FCV-2-95, RFP 2B SUCTION VALVE ____
   - 2-FCV-2-108, RFP 2C SUCTION VALVE. ____

7. **VERIFY** at least one condensate pump running. ____

8. **VERIFY** at least one condensate booster pump running. ____

9. **ADJUST** 2-LIC-3-53, RFW START-UP LEVEL CONTROL, to control injection (Panel 2-9-5). ____

10. **VERIFY** RFW flow to RPV. ____

LAST PAGE

2-EOI APPENDIX-5A
Rev. 8
Page 3 of 4

15. **RAISE** RFPT 2A(2B)(2C) speed UNTIL RFP discharge pressure is approximately equal to RPV pressure using ANY of the following methods on Panel 2-9-5:

- Using individual 2-HS-46-8A(9A)(10A), RFPT 2A(2B)(2C) SPEED CONT RAISE/LOWER switch in MANUAL GOVERNOR, ____

OR

- Using individual 2-SIC-46-8(9)(10), RFPT 2A(2B)(2C) SPEED CONTROL PDS in MANUAL, ____

OR

- Using 2-LIC-46-5, REACTOR WATER LEVEL CONTROL PDS, in MANUAL with individual 2-SIC-46-8(9)(10), RFPT 2A(2B)(2C) SPEED CONTROL PDS in AUTO. ____

16. **SLOWLY RAISE** speed of RFPT UNTIL RFW flow to the RPV is indicated using ANY of the following methods on Panel 2-9-5:

- Using individual 2-HS-46-8A(9A)(10A), RFPT 2A(2B)(2C) SPEED CONT RAISE/LOWER switch in MANUAL GOVERNOR, ____

OR

- Using individual 2-SIC-46-8(9)(10), RFPT 2A(2B)(2C) SPEED CONTROL PDS in MANUAL, ____

OR

- Using 2-LIC-46-5, REACTOR WATER LEVEL CONTROL PDS, in MANUAL with individual 2-SIC-46-8(9)(10), RFPT 2A(2B)(2C) SPEED CONTROL PDS in AUTO. ____

17. **ADJUST** RFPT speed as necessary to control injection using ANY of the following methods on Panel 2-9-5:

- Using individual 2-HS-46-8A(9A)(10A), RFPT 2A(2B)(2C) SPEED CONT RAISE/LOWER switch in MANUAL GOVERNOR, ____

OR

- Using individual 2-SIC-46-8(9)(10), RFPT 2A(2B)(2C) SPEED CONTROL PDS in MANUAL, ____

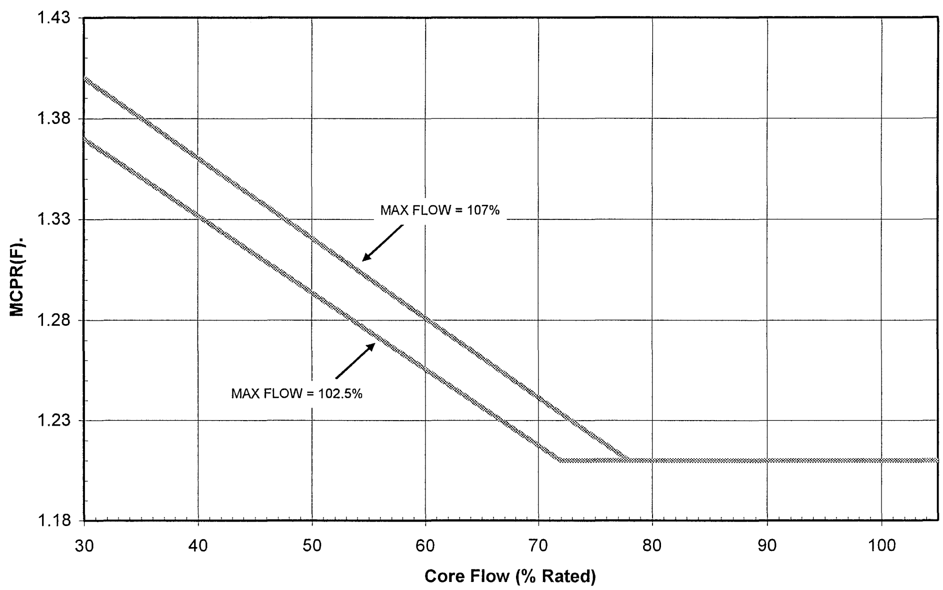
OR

- Using 2-LIC-46-5, REACTOR WATER LEVEL CONTROL PDS, in MANUAL with individual 2-SIC-46-8(9)(10), RFPT 2A(2B)(2C) SPEED CONTROL PDS in AUTO. ____

18. WHEN ...RPV level is approximately equal to desired level AND automatic level control is desired,
THEN ...**PLACE** 2-LIC-46-5, REACTOR WATER LEVEL CONTROL PDS, in AUTO with individual 2-SIC-46-8(9)(10), RFPT 2A(2B)(2C) SPEED CONTROL PDS in AUTO. ____

LAST PAGE

Figure 12
Flow Dependent MCPR Limit - MCPR(F)
(All Fuel)



Max Core Flow 102.5% Rated

Core Flow (% rated)	MCPR(F)
30	1.37
72	1.21
102.5	1.21

Max Core Flow 107% Rated

Core Flow (% rated)	MCPR(F)
30	1.40
78	1.21
107	1.21

These values bound both Turbine Bypass In-Service and Out-Of-Service.
These values bound both Recirculation Pump Trip In-Service and Out-Of-Service.

The 102.5% maximum flow line is used for operation up to 100% rated flow.
The 107% maximum flow line is used for operation up to 105% rated flow (ICF).

Technical Reference(s): OPDP-10 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/23/2008

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

NPG Standard Department Procedure	License Status Maintenance, Reactivation and Proficiency for Non-Licensed Positions	OPDP-10 Rev. 0000 Page 14 of 30

Appendix C
(Page 1 of 3)

Browns Ferry Nuclear Plant Requirements for Maintaining Active License Status

1.0 PURPOSE

The purpose of this appendix is to provide administrative instructions in order to comply with 10CFR55.53 (e), ... "actively performing the functions of an operator or senior operator."

2.0 REFERENCES/BACKGROUND

A. References

1. 10 CFR 50.54(m)(2)(i)
2. 10 CFR 55.4
3. 10 CFR 55.53(e)
4. NUREG-1262 - Preface; pages 71-80
5. Technical Specification

B. To maintain active status, per 55.53(e), Conditions of License, the licensee shall actively perform the functions of an operator or senior operator on a minimum of seven (7) 8-hour or five (5) 12-hour shifts per calendar quarter.

C. Actively performing the functions of an operator or senior operator means that an individual has a position on the shift crew that requires the individual to be licensed as defined in Technical Specification, and that the individual carries out and is responsible for the duties covered by that position.

D. Technical Specifications and 10 CFR 50.54 specify the minimum requirement per shift.

E. Licensed personnel who do not meet these requirements are designated as inactive licensees.

3.0 RESPONSIBILITIES

A. All licensed personnel who maintain an active license shall comply with these requirements.

B. All licensed personnel who maintain an active license and are OFF SHIFT (not part of a rotating shift) shall provide on-shift documentation quarterly to the Operations Superintendent. [Appendix D].

C. The Operations Superintendent is responsible for administering this program and documentation.

NPG Standard Department Procedure	License Status Maintenance, Reactivation and Proficiency for Non-Licensed Positions	OPDP-10 Rev. 0000 Page 15 of 30

Appendix C
(Page 2 of 3)

Browns Ferry Nuclear Plant Requirements for Maintaining Active License Status

4.0 INSTRUCTIONS

A. Individuals assigned to the following positions, AND NO OTHERS, on each shift, are considered to be actively performing the functions of an operator or senior operator in order to maintain active license status:

Browns Ferry Nuclear

1. Shift Manager
2. Unit 1 Unit Supervisor [Control Room SRO]
3. Unit 2 Unit Supervisor [Control Room SRO]
4. Unit 3 Unit Supervisor [Control Room SRO]
5. Unit 1 Board and Desk ROs
6. Unit 2 Board and Desk ROs
7. Unit 3 Board and Desk ROs

B. To be granted credit for a shift, the individual will be present from shift turnover thru shift turnover. Short absences from the Control Room are acceptable (i.e., rest room visits). Absences from the Control Room for extended periods (i.e., Fitness-for-Duty testing) will not count towards shift functions. For these type of cases, the time absence will be made up by working additional time on another shift or an additional shift.

C. The shift period is defined by the schedule worked by the rotating shift crews. Either 12-hour or 8-hour shifts is the normal. If a 12-hour shift rotation is used, then a minimum of five (5) shifts in a licensed position per quarter, or if an 8-hour shift rotation is used, then a minimum of seven (7) shifts in a licensed position per quarter is required in order to remain "active."

D. Technical Specifications / 10CFR50 for each site contains the requirement for the minimum number of licenses required. However, only the positions listed for the applicable site as listed in 4.0A above qualify for license maintenance.

NPG Standard Department Procedure	License Status Maintenance, Reactivation and Proficiency for Non-Licensed Positions	OPDP-10 Rev. 0000 Page 16 of 30

Appendix C
(Page 3 of 3)

Browns Ferry Nuclear Plant Requirements for Maintaining Active License Status

4.0 INSTRUCTIONS (continued)

E. If the operating crews convert from an 8-hour to a 12-hour, or a 12-hour to an 8-hour shift rotation schedule during a calendar quarter, then the number of shifts required to be worked in a licensed position to be credited for active license maintenance on the combination of shifts (8's and 12's) will be in accordance with the following:

8-Hour Shifts TO	12-Hour Shifts	12-Hour Shifts TO	8-Hour Shifts
# Shifts Completed Prior to Change	# Additional Shifts Needed On New Schedule	# Shifts Completed Prior to Change	# Additional Shifts Needed On New Schedule
6	1	4	2
5	2	3	3
4	3	2	5
3	3	1	6
2	4	0	7
1	5	-	-
0	5	-	-

F. The individual assigned to one of the seven (7) positions designated for maintaining an active license, shall log "in" and "out" on the Narrative Log for each shift worked.

G. The Shift Manager on each shift shall verify that the data entered into the "Shift Staffing Log" in the Narrative Log is correct for their shift.

H. A Shift Manager shall actively perform the functions of a Shift Manager a minimum of seven 8-hour or five 12-hour shifts per calendar quarter to remain current.

5.0 DOCUMENTATION

A. Appendix D contains the form "(Active) Licensed Off-Shift Personnel Quarterly On-Shift Time Documentation" that is submitted by active off-shift licensed individuals each quarter to the Operations Superintendent.

B. The Control Room logs are the legal record of watchstander assignment.

NPG Standard Department Procedure	License Status Maintenance, Reactivation and Proficiency for Non-Licensed Positions	OPDP-10 Rev. 0000 Page 18 of 30

Appendix E
(Page 1 of 5)

Browns Ferry Nuclear Plant Requirements for Returning an Inactive License to Active Status

1.0 PURPOSE

This appendix is intended to provide additional guidance, to return a licensed individual to an active status.

2.0 REFERENCES/BACKGROUND

A. The Code of Federal Regulation, 10 CFR55.53 f(2) specifies returning a license to active status. The intent of the law is to ensure proficiency in the conduct of licensed activities prior to assuming licensed duties. The following requirements are addressed as part of this law:

1. The qualifications and status of the licensee are current and valid. This requirement ensures the licensee has completed all required requalification training, including plant modifications and industry events; and secondly, that all conditions of his/her license are still being met.

2. This licensee has completed a minimum of 40 hours of shift functions under the direction of a reactor operator or senior operator, as appropriate, and in the position to which the individual will be assigned. This ensures that an active license is directing or performing the manipulations of plant controls, and allows the inactive individual to obtain proficiency at his/her watch station. Included within the minimum of 40 hours is the following:

   a. A complete review of turnover procedures by the reactor operator or senior reactor operator as appropriate for the position, to ensure that the licensee is familiar with current shift turnover practices.

   b. A complete tour of the plant, to ensure the individual is aware of changing plant conditions that have occurred since he/she has been inactive. The individual performing the tour will be accompanied by a Licensed Reactor Operator or a Licensed Senior Reactor Operator, as appropriate.

3.0 RESPONSIBILITIES

A. All licensed personnel who maintain an active license shall comply with these requirements. The Operations Superintendent is responsible for administering the process.

NPG Standard Department Procedure	License Status Maintenance, Reactivation and Proficiency for Non-Licensed Positions	OPDP-10 Rev. 0000 Page 19 of 30

Appendix E
(Page 2 of 5)

Browns Ferry Nuclear Plant Requirements for Returning an Inactive License to Active Status

4.0 INSTRUCTIONS

A. The following guidelines are to be used when reactivating a license:

1. Prior to standing the minimum of 40 hours of shift functions, the licensed individual shall meet with the Operation Training Manager and the Operations Superintendent to discuss his/her current status and any standards and/or expectations. For certain individuals, additional requirements may be imposed (greater than those required by law) if directed by the Operations Superintendent.

2. The following positions are the only ones that qualify for reactivation of a license:

   Browns Ferry Nuclear

   a. Shift Manager

   b. Unit 1 Unit Supervisor [Control Room SRO]

   c. Unit 2 Unit Supervisor [Control Room SRO]

   d. Unit 3 Unit Supervisor [Control Room SRO]

   e. Unit 1 Board and Desk ROs

   f. Unit 2 Board and Desk ROs

   g. Unit 3 Board and Desk ROs

3. The individual shall be under the direct supervision of an active licensed individual in the position to which the individual will be assigned. To receive credit for a shift, the individual will be present from shift turnover thru shift turnover. Short absences from the Control Room are acceptable (i.e., rest room visits); however, the total time in the Control Room under supervision will total at least 40 hours (this 40 hours does not include the plant tour).

   To ensure that the minimum of 40 hours is obtained in the Control Room under supervision, the break-in period will be seven (7)-8 hour shifts or five (5)-12 hour shifts. This applies to all positions used to re-activate a license to active status.

4. The individual shall make a Narrative log entry at the start of the shift which will include the following at a minimum:

   a. Name and time of assuming shift

   b. Shift Position (as identified in 4.0A.2) assumed under direction

   c. Name of the operators (Board and Desk), Control Room SRO, or Shift Manager providing supervision.

NPG Standard Department Procedure	License Status Maintenance, Reactivation and Proficiency for Non-Licensed Positions	OPDP-10 Rev. 0000 Page 20 of 30

Appendix E
(Page 3 of 5)

Browns Ferry Nuclear Plant Requirements for Returning an Inactive License to Active Status

4.0 INSTRUCTIONS (continued)

5. The individual shall make a Narrative Log entry at the end of the shift indicating they have completed the shift under supervision. A copy of the Narrative log for each shift worked shall be obtained for processing after the break-in is complete. This will be the entire log for the shift worked and not selected entries.

6. The individual shall complete Appendix G for each shift listing unit, shift, position assuming, along with the activities the individual was personally involved in. Time, Position, Unit, Activity, and Date must be filled out for each activity performed. The position the individual is holding must be one of the seven indicated in step 4.0A.2. Appendix H is to be used to account for a plant tour and shift turnover briefing. Appendix H is required to be signed by the Operations Superintendent ensuring that all appendixes have been reviewed and once reviewed, these appendixes will be submitted with the reactivation documentation and will become part of the individuals training record.

7. If license re-activation is for a multi-unit site, then the individual shall divide their time between the units to ensure adequate break-in in all license areas they may be assigned. The amount of time in each Control Room does not have to be equalized between units, but should be enough to ensure that the individual will be ready to assume the shift once their license is returned to active status.

8. If an individual moves from one unit to another unit during the same shift for the purpose of breaking-in on the other unit, the individual shall make an log entry indicating that they are moving to the other unit to continue their break-in. Another entry, to include the areas in 4.0A.4, will be made when the individual goes under instruction on the new unit. This requirement is not applicable to an individual being re-activated as a Shift Manager since the break-in would still be under the same individual.

9. The individual shall review the turnover procedures with an active reactor operator or senior reactor operator, as applicable. The following are the minimum procedures that will be reviewed:

   a. Plant Operations Manager, Operations Superintendent, and/or Operations Support Superintendent will decide the requirements here.

Examination Outline Cross-reference:	Level	RO	SRO
G2.1.44	Tier #		3
Conduct of Operations: Knowledge of RO duties in the control room during fuel handling.	Group #		
	K/A #	G2.1.44	
	Importance Rating	3.9	3.8

Proposed Question: **SRO #20**

Unit-2 is in Mode 5 loading fuel into the reactor when the following indications are received:

- FUEL POOL FLOOR AREA RADIATION HIGH (2-XA-55-3A, window 1).
- REFUELING ZONE EXHAUST RADIATION HIGH (2-XA-55-3A, window 34).
- RX BLDG AREA RADIATION HIGH (2-XA-55-3A, window 22).
- REACTOR ZONE EXHAUST RADIATION HIGH (2-XA-55-3A, window 21).
- SRM PERIOD (2-XA-55-5A, Window 20).

Which ONE of the following describes the required actions for this condition?

Direct the Unit Operator to enter _____(1)_____ and take action to _____(2)_____.

	(1)	(2)
A.	2-AOI-79-1, "Fuel Damage During Refueling,"	evacuate ALL personnel from the Refuel Floor.
B.	2-AOI-79-2, "Inadvertent Criticality During Incore Fuel Movements,"	evacuate ALL personnel from the Refuel Floor.
C.	2-AOI-79-1, "Fuel Damage During Refueling,"	evacuate ONLY non-essential personnel from the Refuel Floor.
D.	2-AOI-79-2, "Inadvertent Criticality During Incore	evacuate ONLY non-essential personnel from the Refuel Floor.

Proposed Answer: **B**

Explanation:

a. Part (1) is incorrect. All four radiation annunciators are common to each AOI, but the SRM Period annunciator is indicative of inadvertent criticality and not fuel damage. Part (2) is correct for inadvertent criticality due to the potential for lethal radiation levels.

b. Correct answer.

c. Part (1) is incorrect as stated in (a) above. Part (2) is incorrect. Evacuation of non-essential personnel ONLY is required for fuel damage during handling.

d. Part (1) is incorrect as stated in (a) above. Part (2) is incorrect as stated in (c) above.

Technical Reference(s): 2-AOI-79-1, 2-AOI-79-2 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/19/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments: To answer this question without reference requires the candidate to analyze the intent of the two potential AOIs. Specifically, what actions are required to correct or mitigate the problem. Since the actions to correct a damaged fuel bundle during handling require personnel to operate refueling equipment located on the Refuel Floor, evacuation of ALL personnel is not possible if the procedure is to be completed. The actions required to control or mitigate an inadvertent criticality are carried out from the control room, therefore no personnel are necessary on the Refuel Floor and evacuating ALL personnel is appropriate.

BFN Unit 2	Inadvertent Criticality During Incore Fuel Movements	2-AOI-79-2 Rev. 0013 Page 3 of 8

1.0 PURPOSE

This instruction provides the symptoms, automatic actions and operator actions for an inadvertent criticality during incore fuel movements.

2.0 SYMPTOMS

A. Possible annunciators in alarm:

1. CONTROL ROD WITHDRAWAL BLOCK (2-XA-55-5A, Window 7).
2. SRM HIGH/INOP (2-XA-55-5A, Window 13).
3. SRM PERIOD (2-XA-55-5A, Window 20).
4. REACTOR CHANNEL A AUTO SCRAM (2-XA-55-5B, Window 1).
5. REACTOR CHANNEL B AUTO SCRAM (2-XA-55-5B, Window 2).
6. FUEL POOL FLOOR AREA RADIATION HIGH (2-XA-55-3A, Window 1).
7. REACTOR ZONE EXHAUST RADIATION HIGH (2-XA-55-3A, Window 21).
8. RX BLDG AREA RADIATION HIGH (2-XA-55-3A, Window 22).
9. REFUELING ZONE EXHAUST RADIATION HIGH (2-XA-55-3A, Window 34).
10. REACTOR CHANNEL A MAN SCRAM (2-XA-55-5B, Window 8).
11. REACTOR CHANNEL B MAN SCRAM (2-XA-55-5B, Window 9).

B. SRM period lights illuminated.

C. Rising count rate on SRM meters.

D. Rising power level on IRM recorders.

E. Rising radiation level on refuel floor.

BFN Unit 2	Fuel Damage During Refueling	2-AOI-79-1 Rev. 0017 Page 3 of 7

1.0 PURPOSE

This instruction provides the symptoms, automatic actions and operator actions for a fuel damage accident.

2.0 SYMPTOMS

A. Possible annunciators in alarm:

1. FUEL POOL FLOOR AREA RADIATION HIGH (2-XA-55-3A, window 1).
2. AIR PARTICULATE MONITOR RADIATION HIGH (2-XA-55-3A, window 2).
3. RX BLDG, TURB BLDG, RF ZONE EXH RADIATION HIGH (2-XA-55-3A, window 4).
4. REACTOR ZONE EXHAUST RADIATION HIGH (2-XA-55-3A, window 21).
5. RX BLDG AREA RADIATION HIGH (2-XA-55-3A, window 22).
6. REFUELING ZONE EXHAUST RADIATION HIGH (2-XA-55-3A, window 34).

B. Gas bubbles visible, in the Spent Fuel Storage Pool and/or Reactor Cavity, attributed to physical fuel damage.

C. Known dropped or physically damaged fuel bundle.

D. Portable CAM in alarm.

E. Radiation level on the Refuel Floor is greater than 25 mr/hr and cause is unknown.

BFN Unit 2	Inadvertent Criticality During Incore Fuel Movements	2-AOI-79-2 Rev. 0013 Page 5 of 8

4.0 OPERATOR ACTIONS

4.1 **Immediate Actions**

[1] IF unexpected criticality is observed following control rod withdrawal, THEN

REINSERT the control rod. ☐

[2] IF all control rods CANNOT be fully inserted, THEN

MANUALLY SCRAM the reactor. ☐

[3] IF unexpected criticality is observed following the insertion of a fuel assembly, THEN

PERFORM the following: ☐

[3.1] **VERIFY** fuel grapple latched onto the fuel assembly handle AND immediately **REMOVE** the fuel assembly from the reactor core. ☐

[3.2] IF the reactor can be determined to be subcritical **AND** no radiological hazard is apparent, THEN

PLACE the fuel assembly in a spent fuel storage pool location with the least possible number of surrounding fuel assemblies, leaving the fuel grapple latched to the fuel assembly handle. ☐

[3.3] IF the reactor CANNOT be determined to be subcritical OR adverse radiological conditions exist, THEN

TRAVERSE the refueling bridge and fuel assembly away from the reactor core, preferably to the area of the cattle chute, AND **CONTINUE** at Step 4.1[4]. ☐

[4] IF the reactor CANNOT be determined to be subcritical OR adverse radiological conditions exist, THEN

EVACUATE the refuel floor. ☐

BFN Unit 2	Fuel Damage During Refueling	2-AOI-79-1 Rev. 0017 Page 5 of 7

4.0 OPERATOR ACTIONS

4.1 Immediate Actions

[1] **STOP** all fuel handling. ☐

[2] **EVACUATE** all non-essential personnel from Refuel Floor. ☐

4.2 Subsequent Actions

CAUTION

The release of iodine is of major concern. If gas bubbles are identified at any time, Iodine release should be assumed until RADCON determines otherwise.

[1] **VERIFY** secondary containment is intact.
(REFER TO Tech Spec 3.6.4.1) ☐

[2] **IF** any EOI entry condition is met, **THEN**

ENTER the appropriate EOI(s). ☐

[3] **VERIFY** automatic actions. ☐

[4] **NOTIFY** RADCON to perform the following:

- **EVALUATE** the radiation levels. ☐
- **MAKE** recommendation for personnel access. ☐
- **MONITOR** around the Reactor Building Equipment Hatch, at levels below the Refuel Floor, for possible spread of the release. ☐

[5] **REFER TO** EPIP-1 for proper notification. ☐

Examination Outline Cross-reference:	Level	RO	SRO
G2.2.39	Tier #		3
Knowledge of less than one hour technical specification action statements for systems.	Group #		
	K/A #	G2.2.39	
	Importance Rating	3.9	4.5

Proposed Question: **SRO # 21**

Given the following plant conditions:

- Unit 2 is at 100% rated power.
- RHR Loop II is INOP 2 days into a 7 day action statement per TSR 3.5.1.A.

Which ONE of the following equipment failures would result in the most limiting Technical Specification LCO and the reporting requirements that would result from that failure?

If ______(1)______ was declared INOPERABLE, a ____(2)____ report to the NRC would be required.

	(1)	(2)
A.	Core Spray Loop I	4 hour
B.	Core Spray Loop I	1 hour
C.	Diesel Generator A	4 hour
D.	Diesel Generator A	1 hour

Proposed Answer: **A**

Explanation:

a. Correct answer. Two low pressure ECCS subsystems INOP requires entry into Applicability Statement 3.0.3 immediately in accordance with 3.5.1.H.

b. Part (1) is correct. Part (2) is incorrect. A shutdown required by Technical Specification is no longer a 1 hour report. Reporting requirements have been revised such that a 4 hour report is required for this condition.

c. Part (1) is incorrect. An INOP D/G will result in implementation of Applicability Statement 3.0.3, but there is a 4 hour grace period before redundant subsystems, trains and components are declared inoperable in accordance with 3.8.1.B.2. Part (2) is correct.

d. Part (1) is incorrect as stated in (c) above. Part (2) is incorrect as stated in (b) above.

Technical Reference(s): U1 TSR 3.5.1, U1 TSR 3.8.1 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank #

Modified Bank # (Note changes or attach parent)

New 7/23/2008 RMS

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge

Comprehension or Analysis X

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS) AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS - Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable. <u>OR</u> One low pressure coolant injection (LPCI) pump in both LPCI subsystems inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition C, D, E, or F not met.	G.1 AND G.2	Be in MODE 3. Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours
H. Two or more low pressure ECCS injection/spray subsystems inoperable for reasons other than Condition A. OR HPCI System and one or more ADS valves inoperable.	H.1	Enter LCO 3.0.3.	Immediately

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources - Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System;

b. Unit 1 and 2 diesel generators (DGs) with two divisions of 480 V load shed logic and common accident signal logic OPERABLE; and

c. Unit 3 DG(s) capable of supplying the Unit 3 4.16 kV shutdown board(s) required by LCO 3.8.7, "Distribution Systems - Operating."

APPLICABILITY: MODES 1, 2, and 3.

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	Verify power availability from the remaining OPERABLE offsite transmission network.	1 hour AND Once per 8 hours thereafter
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one shutdown board concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore required offsite circuit to OPERABLE status.	7 days AND 14 days from discovery of failure to meet LCO
B. One required Unit 1 and 2 DG inoperable.	B.1	Verify power availability from the offsite transmission network.	1 hour AND Once per 8 hours thereafter
	AND		

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Declare required feature(s), supported by the inoperable Unit 1 and 2 DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	B.3.1	Determine OPERABLE Unit 1 and 2 DG(s) are not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	B.3.2	Perform SR 3.8.1.1 for OPERABLE Unit 1 and 2 DG(s).	24 hours
	<u>AND</u>		
	B.4	Restore Unit 1 and 2 DG to OPERABLE status.	7 days <u>AND</u> 14 days from discovery of failure to meet LCO

(continued)

NPG Standard Programs and Processes	Regulatory Reporting Requirements	SPP-3.5 Rev. 0018 Page 18 of 64

Appendix A
(Page 2 of 11)

3.0 REQUIREMENTS

NOTES

1) Internal management notification requirements for plant events are found in Appendix D. Operations and the Plant Manager (or Duty Plant Manager) are responsible for making these internal management notifications.

2) NRC NUREG-1022, Supplements and subsequent revisions should be used as guidance for determining reportability of plant events pursuant to §50.72 and §50.73.

3.1 Immediate Notification - NRC

TVA is required by §50.72 to notify NRC immediately if certain types of events occur. This appendix contains the types of events and the allotted time in which NRC must be notified. (Refer to Form SPP-3.5-1). Operations is responsible for making the reportability determinations for §50.72 and §50.73 reports. Operations is responsible for making the immediate notification to NRC in accordance with §50.72.

Notification is via the Emergency Notification System. If the Emergency Notification System is not operative, use a telephone, telegraph, mailgram, or facsimile.

NOTE

The NRC Event Notification Worksheet may be used in preparing for notifying the NRC.

A. The Immediate Notification Criteria of §50.72 is divided into 1-hour, 4-hour, and 8- hour phone calls. Notify the NRC Operations Center within the applicable time limit for any item which is identified in the Immediate Notification Criteria.

B. The following criteria require 1-hour notification:

1. (Technical Specifications) - Safety Limits as defined by the Technical Specifications which have been violated.

2. §50.72 (a)(1)(i) - The declaration of any of the Emergency classes specified in the licensee's approved Emergency Plan.

NOTE

If it is discovered that a condition existed which met the Emergency Plan criteria but no emergency was declared and the basis for the emergency class no longer exists at the time of discovery, an ENS notification (and notification of the Operations Duty Specialist), within one hour of discovery of the undeclared (or misclassified) event, shall be made. However, actual declaration of the emergency class is not necessary in these circumstances.

NPG Standard Programs and Processes	Regulatory Reporting Requirements	SPP-3.5 Rev. 0018 Page 19 of 64

Appendix A
(Page 3 of 11)

3.1 **Immediate Notification - NRC (continued)**

3. §50.72(b).(1)) - Any deviation from the plant's Technical Specifications authorized pursuant to §50.54(x).

C. The following criteria require 4-hour notification:

1. §50.72(b)(2)(i) - The initiation of any nuclear plant shutdown required by the plant's Technical Specifications.

2. §50.72(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.

3. §50.72(b)(2)(iv)(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. §50.72(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. Such an event may include an onsite fatality or inadvertent release of radioactive contaminated materials.

D. The following criteria require 8-hour notification:

NOTE
The non-emergency events specified below are only reportable if they occurred within three years of the date of discovery.

1. §50.72(b)(3)(ii)(A) - Any event or condition that results in the condition of the nuclear power plant, including its principal safety barriers, being seriously degraded.

2. §50.72(b)(3)(ii)(B) - Any event or condition that results in the nuclear power plant being in an unanalyzed condition that significantly degrades plant safety.

3. §50.72(b)(3)(iv)(A) - Any event or condition that results in valid actuation of any of the systems listed in paragraph (b)(3)(iv)(B) [see list below], except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation.

   a. Reactor protection system (RPS) including: Reactor scram and reactor trip.

Examination Outline Cross-reference:

G2.2.43

Knowledge of the process used to track inoperable alarms.

	RO	SRO
Level	RO	SRO
Tier #		3
Group #		
K/A #	G2.2.43	
Importance Rating	3.0	3.3

Proposed Question: **SRO #22**

Given the following plant conditions:

- Unit-2 is at 100% rated power
- HPCI OIL FILTER DIFF PRESS HIGH 2-PDA-73-53 (9-3F W34) has alarmed.
- Investigation revealed that ΔP transmitter 2-PDS-073-0053 has failed and requires replacement.
- A Work Order was written on 10/15/2008 to disable annunciator (9-3F W34), replace the transmitter when available, then re-enable the annunciator once post-maintenance testing is completed.
- The transmitter has been ordered and is expected to arrive 01/15/2009.

Which ONE of the following describes the required actions per OPDP-4, "Annunciator Disablement?"

A 10CFR50.59 evaluation __(1)__ required prior to disabling the annunciator and this action must be AUDITED every __(2)__ .

	(1)	(2)
A.	is NOT	12-hour shift.
B.	is NOT	30 days.
C.	is	12-hour shift.
D.	is	30 days.

Proposed Answer: **D**

Explanation:

a. Part (1) is incorrect. Per OPDP-4 Appendix A, a 50.59 review is required since the annunciator will be disabled for > 90 days. Part (2) is incorrect. The Disabled Annunciator list is REVIEWED every shift, but is AUDITED every 30 days to ensure a 50.59 review is still not required.

b. Part (1) is incorrect. A 50.59 review is required. Part (2) is correct. The Disabled Annunciator list is audited to ensure 50.59 compliance every 30 days.

c. Part (1) is correct. Per OPDP-4 Appendix A, a 50.59 review is required since the annunciator will be disabled for > 90 days. Part (2) is incorrect. The Disabled Annunciator list is REVIEWED every shift, but is AUDITED every 30 days to ensure a 50.59 review is still not required.

d. Correct answer.Part (1) is incorrect as stated in (c) above. Part (2) is correct. The Disabled Annunciator list is audited to ensure 50.59 compliance every 30 days.

Technical Reference(s):	OPDP-4, U2 TSR 3.3.5.1		(Attach if not previously provided)
Proposed references to be provided to applicants during examination:			None
Question Source:	Bank #		
	Modified Bank #		(Note changes or attach parent)
	New	7/27/2008 RMS	
Question History:	Last NRC Exam		
Question Cognitive Level:	Memory or Fundamental Knowledge		
	Comprehension or Analysis	X	
10 CFR Part 55 Content:	55.41		
	55.43	X	

Comments:

BFN Unit 2	Panel 9-3 2-XA-55-3F	2-ARP-9-3F Rev. 0024 Page 38 of 39

HPCI OIL
FILTER DIFF
PRESS HIGH
2-PDA-73-53

34

(Page 1 of 1)

Sensor/Trip Point:

2-PDS-073-0053 10 psid

Sensor Location: HPCI Turbine, El 519', SE corner RX Bldg.

Probable Cause: The inservice filter is dirty.

Automatic Action: None

Operator Action:
A. **DISPATCH** personnel to switch to clean filter. ☐
B. **INITIATE** WO for dirty filter to be charged. ☐

References: 2-45E620-1 2-47E610-73-2 GE 730E928-4

APPENDIX A
Page 1 of 2

TECHNICAL EVALUATION AND 50.59 APPLICABILITY

1. When an annunciator window/input is disabled as directed/allowed in an approved plant procedure (excluding maintenance or surveillance activities), a separate 50.59 review and Technical Evaluation are not required since the procedure has already been reviewed and approved. The following example would be an alarm disablement per an approved plant instruction:

   - A system operating instruction directs or allows an alarm disablement due to abnormal conditions which are addressed (and restored) by that instruction.

   NOTE The initiation and processing of a work order does NOT constitute in-process maintenance. Refer to Section 5.0 Definitions.

2. If an annunciator window/input is disabled in support of maintenance or surveillance activities, a 50.59 review is not required UNLESS the annunciator will remain disabled for more than 90 days. If 90 days will be exceeded, a 50.59 review shall be completed prior to exceeding 90 days. A Technical Evaluation is required prior to disablement if alarm functions will be disabled for equipment remaining in service (not removed from service/inoperable for the maintenance activity).

   The following example would be considered necessary to support maintenance activities and requires a Technical Evaluation:

   - A pump is tagged with a clearance for maintenance. Its suction pressure switch will be depressurized and disabling the associated low pressure alarm will disable the alarm function for other equipment that must remain in service.

   The following examples would be considered necessary to support maintenance activities and do not require a Technical Evaluation provided the parameter is the only input to the alarm:

   - A pump is tagged with a clearance for maintenance. Its suction pressure switch will be depressurized and the associated low pressure alarm disabled.

   - An instrument is declared inoperable, and any required LCO action(s) are entered for calibration in accordance with an approved maintenance instruction. The alarm from this instrument is disabled.

APPENDIX A
Page 2 of 2

3. When an annunciator window/input must be disabled due to degraded or inoperable equipment with maintenance NOT in progress, a 50.59 review is required prior to disabling the alarm EXCEPT when covered by an approved plant procedure (item 1). A Technical Evaluation is also required EXCEPT when covered by an approved plant procedure (item 1) OR when the affected alarm function is only monitoring equipment which is inoperable/out-of-service and the alarm will be restored prior to declaring the affected equipment operable or returning it to service. The following excerpt from NEI 96-07 is an example of a degraded condition affecting multiple alarm inputs:

- A level transmitter for one Reactor Coolant Pump (RCP) lower oil reservoir failed while at power. The transmitter provides an alarm function, but not an automatic protective action function. The transmitter and associated alarm are described in the UFSAR as protective features for the RCPs, but no technical specification applies. Loss of the transmitter does not result in the loss of operability for any technical specification equipment. The transmitter fails in a direction resulting in a continuous alarm in the control room. The alarm circuitry provides a common alarm for both the upper and lower oil reservoir circuits, so transmitter failure causes a hanging alarm and a masking of proper operation of the remaining functional transmitter. Precautionary measures are taken to monitor lower reservoir oil level as outlined in the alarm manual using available alternate means. An interim compensatory action is proposed to lift the leads (temporary change) from the failed transmitter to restore the alarm function for the remaining functioning transmitter. Lifting the leads is a compensatory action (temporary change) that is subject to 10 CFR 50.59. The 10 CFR 50.59 screening would be applied to the temporary change itself (lifted leads), not the degraded condition (failed transmitter) to determine its impact on other aspects of the facility described in the UFSAR. If screening determines that no other UFSAR-described SSCs would be affected by this compensatory action, the temporary change would screen out, i.e., not require a 10 CFR 50.59 evaluation.

4. If an annunciator window or input must be disabled for other reasons (e.g. due to actual plant parameters which are known/suspected to be at or exceeding the alarm setpoint), then a 50.59 review and Technical Evaluation are required prior to disabling the alarm, EXCEPT when covered by an approved plant procedure (item 1).

Employees Performing Activities That will Bring in Alarms

A. Provide a list of affected alarms to the Unit Operator before starting work.

B. IF the annunciator is out of service due to maintenance or other abnormal condition, THEN

Verify WO written which identifies out-of-service annunciator.

C. Ensure out-of-service indicator is placed on each applicable annunciator window.

Employees Performing Activities That will Bring in Alarms

D. When maintenance or surveillance activities are complete, then notify Operations to remove out-of-service indicator from affected annunciator windows.

Unit Operator/Designee

E. Remove out-of-service indicator on alarm windows which have been enabled, UNLESS there are other inputs to the affected window which remain disabled by OPDP-4 or another approved plant procedure.

3.5 Review and Audit

The Disabled Annunciator Book is reviewed during shift turnover (OPDP-1) to ensure disabled alarms are documented as required.

On a monthly basis, the Disabled Annunciator Book should be audited to verify that 10CFR50.59 reviews have been completed as required. A 10CFR50.59 review shall be completed for any annunciators disabled for maintenance which will exceed 90 days prior to the next review.

4.0 RECORDS

4.1 QA-Records

Disabled Alarm Checklist OPDP-4-1
Annunciator Disablement Technical Evaluation OPDP-4-5

4.2 Non-QA Records

Disable Alarm Index Sheet OPDP-4-2
Disabled Alarm Compensatory Measures OPDP-4-3

Examination Outline Cross-reference:	Level	RO	SRO
G2.3.13	Tier #		3
Knowledge of radiological safety procedures pertaining to licensed operator duties.	Group #		
	K/A #	G2.3.13	
	Importance Rating	3.4	3.8

Proposed Question: **SRO # 23**

Valve line-up checklists are being conducted on Unit 2 and the initial positioning has been completed for a valve located in the drywell.

Independent verification (IV) of the valve should only take 15 minutes, but Radcon reports that the general area dose rate is now 150 mrem/hr.

Which ONE of the following describes the circumstances, if any, that allow the Shift Manager to waive the IV requirement for this valve?

A. Independent verification may be waived by the Shift Manager ONLY if alternate means of verification are available.

B. Independent verification can not be waived; direct Radcon to determine other means of dose reduction.

C. Independent verification may be waived by the Shift Manager ONLY if the system is not an ECCS system.

D. Independent verification may be waived by the Shift Manager solely based on ALARA concerns.

Proposed Answer: **D**

Explanation:

a. Incorrect. Alternate verification methods may be used if available, but are not a prerequisite for waiving IV requirements due to the excessive radiation exposure given in the stem. If the word "only" is removed from the distracter, it would be correct.

b. Incorrect. Being located inside the Drywell implies this valve meets the critical activity requirements of SPP 10.3 Step 3.4.3.A, and is "absolutely necessary for SSCs to function." Even so, excessive radiation exposure to the extent given in the stem warrants waiving IV requirements. If the anticipated dose was closer to the limit, the actions to have Radcon take actions to reduce the dose rate may have been appropriate.

c. Incorrect. According to SPP 10.3, the Shift Manager may authorize deviations from the requirements if needed If the word "only" is removed from the distracter, it would be correct.

d. Correct answer.

Technical Reference(s): SPP 10.3 (Attach if not previously provided)

Proposed references to be provided to applicants during examination: None

Question Source: Bank # G2.3.2

Modified Bank # (Note changes or attach parent)

New

Question History: Last NRC Exam

Question Cognitive Level: Memory or Fundamental Knowledge X

Comprehension or Analysis

10 CFR Part 55 Content: 55.41

55.43 X

Comments:

Procedure Preparers

C. The preparers of site procedures/instructions and work documents are responsible for the following:

1. Ensuring that IV or second-party verification requirements are specified as appropriate.

2. Ensuring the type of verification is clearly identified.

D. Shift Manager

The shift manager (SM) shall be responsible for the following:

1. Determining the corrective actions to be taken when discrepancies are discovered.

2. Ensuring that personnel assigned to perform IV and second-party verification are qualified.

3. Authorizing deviations from normal verification practices if needed.

E. Training Manager

Develop, conduct, and document training of personnel engaged in verification activities.

F. All Personnel

Inform their respective foreman or supervisor if they have been assigned a verification which they do not feel qualified to perform. In the event their respective supervisor is not available, they will contact the SM for resolution before continuing the verification.

3.2 Qualifications

Individuals assigned IV or second-party verification responsibilities shall meet the following qualification requirements:

A. Technically qualified to perform the assigned task (experience, position description, familiarity with the task, etc., should be considered) as determined by the responsible manager.

B. Completed training on verification program requirements.

3.3.2 Alternate Verification Techniques

Alternate verification techniques may be used by the verifier where specified by approved procedures, valve and breaker line-up checklists, or at the discretion of shift supervisory personnel. Examples include the following:

A. Use of remote position indicators. (Indicating lights in the control room, at the switchgear, or at local controls are the normal method of determining motor-operated and air-operated valve position.)

B. Use of process parameters (e.g., pressure, flow, vibration, current, voltage, potential lamps, etc.).

C. Observation of the valve stem to aid in determination of valve position if the valve stem is marked by paint (when fully closed) or other positive verification methods.

D. Authorized scribe marks on valve stems, properly labeled with the throttled position.

E. Functional mechanical position indicators.

F. A post maintenance/modification functional test provided the testing verifies each component under consideration.

3.3.3 Circuit Breakers

Circuit breaker verification will include a local inspection of the breaker, control power switches or fuses, and other equipment as outlined below:

A. To verify a breaker is removed from service, the independent or second-party verifier will ensure control power is isolated (if required) by inspecting appropriate switches, fuses or fuse blocks, and ensure the breaker is racked out to the disconnected position, as applicable.

B. To verify a breaker is restored to service, the independent or second-party verifier will ensure control power is energized by inspecting appropriate switches, indicating lights, fuses or fuse blocks, and will ensure the breaker is fully racked in with closing springs charged as applicable. Where practical, the end device should be operated following the reinstallation of a breaker. The verifier will also ensure the cubicle door is in good condition with all fasteners tight.

3.4 Verification Requirements

When determination of these requirements is not clear, the responsible manager will designate the requirements. If there is disagreement, the operations manager will designate the requirements.

3.4.1 IV or second-party verification is required for those systems listed in Appendix A and shall include the following as a minimum:

A. All valves, breakers, and other components in safety-related systems where an inappropriate positioning could adversely affect system/plant operation or containment integrity.

B. All valves, breakers, and other components in fire protection system major flow paths, including fire fighting water supply and storage, carbon dioxide storage systems, fire protection systems, and all components necessary for the system to function and supply extinguishing media to the fire.

C. All valves, breakers, and other components in gaseous and liquid radioactive waste handling and processing systems where an inappropriate positioning could result in radioactive material release to the environment.

3.4.2 <u>Activities Exempt From Independent and Second-Party Verification Requirements</u>

A. Calculations performed by qualified computer software.

B. Activities for which verifications would be required and one or more of the following conditions exist:

- Out-of-service systems/channels/components for which configuration control will <u>not</u> be maintained and will be verified to be in the proper configuration during the return to operable status.
- Activities involving significant radiation exposure. As a guideline, an exposure greater than 10 mrem TEDE to perform the verification would be considered excessive.
- Activities occurring during emergency conditions (imminent danger to plant or personnel) requiring rapid personnel action.
- Activities that could jeopardize personnel safety.
- Components located within locked/covered/controlled access areas provided access to the area has not occurred since the last documented verification.

For these instances, the decision not to perform a verification is to be documented on the procedure/instruction or work document.

3.4.3 <u>Independent Verification Requirements</u>

IV is used to confirm that an activity or condition has been implemented in conformance with specified requirements. The individual performing the IV must physically check the condition without relying on observation or verbal confirmation by the initial performer. However, the independent verifier may be involved in unrelated portions of the same activity. IV is required for the following:

A. Any critical activity that, if done improperly, could remain undetected until that structure, system, or component was called upon to mitigate an accident or transient as described in the FSAR, Fire Protection Plan, Security Plan, or ODCM. Critical implies the activity is absolutely necessary for Systems, Structures, and Components to function.

B. Initial system lineups, or restoring components to their required position/condition following an outage where the system status was not maintained.

C. Normal system line-up periodic checks conducted during operating conditions. In this case, the individual performing the periodic check of the original lineup is considered to be the independent verifier and an additional second check is not required. IV of locked components consists of checking that required locking devices are present and intact.

D. Installation and removal of temporary alterations covered by the TACF Program.

3.4.4 Second-Party Verification Requirements

Second-party verification is used in lieu of IV for the activities listed below. When performing a second-party verification, an agreement must be reached between the performer and the verifier that the activity/manipulation to be performed is correct before performance.

A. Activities where performing an IV would by itself invalidate the actions or conditions the performer is attempting to establish.

EXAMPLE

Verification of throttled valve position, locked valve position, installation and removal of high voltage line or bus PT fuses, installation and removal of fuses in fuse blocks/clips which are normally hidden from view, etc.

B. Activities which, if improperly accomplished or incorrectly identified, may cause any of the following:

- Immediate plant trip or transient
- Safety system actuation
- Start of equipment
- Equipment failure/damage
- Release of radioactive material
- Personnel injury

EXAMPLE

Removal or installation of wires, jumpers, or other connections; valve, switch, or breaker manipulations; removal or installation of fuses or circuit cards; etc.

Examination Outline Cross-reference:	Level	RO	SRO
G2.4.43	Tier #		3
Knowledge of emergency communications systems and techniques.	Group #		
	K/A #	G2.4.43	
	Importance Rating	3.2	3.8

Proposed Question: **SRO #24**

Given the following plant conditions:

- A transient has occurred on Unit 1 resulting in the following annunciators in alarm:
  - STACK GAS RADIATION HI (1-RA-90-147B)
  - STACK GAS RADIATION HIGH-HIGH (1-RA-90-147A)
  - OG PRETREATMENT RADIATION HIGH (1-RA-90-157A)
  - RX BLDG,TURB BLDG, RF ZONE EXH RADIATION HIGH (1-RA-90-250A)

Which ONE of the following describes the required operator action?

Declare a/an _____(1)_____. Direct a _____(2)_____ to implement Appendix B, "Unit Operator Notifications."

REFERENCE PROVIDED

	(1)	(2)
A.	Notification of Unusual Event	Unit 1 Unit Operator
B	Alert	Unit 1 Unit Operator
C.	Notification of Unusual Event	Unit 2/3 Unit Operator
D.	Alert	Unit 2/3 Unit Operator

Proposed Answer: **C**

Explanation:

a. Part (1) is correct. The Off-Gas pretreatment radiation high is indicative of a NOUE. However, since the transient has occurred on Unit-1, the normal assignment of the Unit-1 Unit Operator to implement Appendix B is not appropriate. EPIP-2 has a NOTE which allows delegation of that action to a Unit Operator on an unaffected unit.

b. Part (1) is incorrect. Conditions do not yet indicate a severity which justifies an ALERT emergency. Part (2) is incorrect as stated in (a) above.

c. Correct answer.

d. Part (1) is incorrect. Conditions do not yet indicate a severity which justifies an ALERT emergency. Part (2) is correct.

Technical Reference(s):	EPIP-1, EPIP-2	(Attach if not previously provided)
Proposed references to be provided to applicants during examination:		EPIP-1 **(Section 1 – 4 ONLY without bases)**
Question Source:	Bank #	
	Modified Bank # SRO 271000G2.4.36	Attached
	New	
Question History:	Last NRC Exam	
Question Cognitive Level:	Memory or Fundamental Knowledge	
	Comprehension or Analysis	X
10 CFR Part 55 Content:	55.41	
	55.43 X	

Comments:

SRO 271000G2.4.36

Given the following plant conditions:

- A transient has occurred on Unit 1 resulting in the following annunciators in alarm:
    - STACK GAS RADIATION HI (1-RA-90-147B)
    - STACK GAS RADIATION HIGH-HIGH (1-RA-90-147A)
    - OG PRETREATMENT RADIATION HIGH (1-RA-90-157A)
    - RX BLDG,TURB BLDG, RF ZONE EXH RADIATION HIGH (1-RA-90-250A)

Which ONE of the following describes the required operator action?

Declare a/an ______(1)______. Fifteen minutes later you determine you must notify _____(2)____ to implement EPIP-13, for dose assessment.

REFERENCE PROVIDED

	(1)	(2)
a.	Notification of Unusual Event	SED
b	Alert	TSC
c.	Notification of Unusual Event	Radcon
d.	Alert	CECC

BROWNS FERRY	EMERGENCY CLASSIFICATION PROCEDURE EVENT CLASSIFICATION MATRIX	EPIP-1

	MSL / OFFGAS RADIATION	LOSS OF DECAY HEAT REMOVAL
	Description	Description
UNUSUAL EVENT	1.4-U Valid MAIN STEAM LINE RADIATION HIGH-HIGH alarm, RA-90-135C OR Valid OG PRETREATMENT RADIATION HIGH alarm, RA-90-157A. OPERATING CONDITION: Mode 1 or 2 or 3	
ALERT		1.5-A Reactor moderator temperature can NOT be maintained below 212° F whenever Technical Specifications require Mode 4 conditions or during operations in Mode 5. OPERATING CONDITION: Mode 4 or 5
SITE EMERGENCY		1.5-S CURVE US Suppression Pool temperature, level and RPV pressure can NOT be maintained in the safe area of Curve 1.5-S. OPERATING CONDITION: Mode 1 or 2 or 3
GENERAL EMERGENCY		

BROWNS FERRY	NOTIFICATION OF UNUSUAL EVENT	EPIP-2

3.3 **Notification of Site Personnel**

NOTE
Normally Appendix B, "Unit Operator Notifications", is conducted by a Unit 1, Unit Operator, Depending upon the affected unit this action may be delegated to a Unit Operator, on an unaffected unit.

3.3.1 **PROVIDE**... a Unit Operator with a completed copy of Appendix A. ☐

AND

DIRECT... the Unit Operator to make personnel notifications per Appendix B, "UNIT OPERATOR NOTIFICATIONS". ☐

CAUTION
Ongoing or anticipated security events may present a danger to site personnel. Do not conduct the notification of site personnel PA message during an ongoing or anticipated security event. All pertinent site personnel PA messages will be conducted per AOI-100-8 for security events.

3.3.2 **CONDUCT** a Plant PA announcement similar to the following: (Dial 687 to obtain the Plant PA) ☐

Let me have your attention please.
This is (name) ________.
A Notification of Unusual Event, Emergency Classification has been declared.
We are currently implementing EPIP-2.

3.3.3 **NOTIFY** the Plant Manager or designee of the Notification of Unusual Event. ☐

REFERENCE MATERIAL

Provided to

CANDIDATE

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT

EMERGENCY PLAN IMPLEMENTING PROCEDURE

EPIP-1

EMERGENCY CLASSIFICATION PROCEDURE

REVISION 43

PREPARED BY: RANDY WALDREP PHONE: 2038

RESPONSIBLE ORGANIZATION: EMERGENCY PREPAREDNESS

APPROVED BY: TONY ELMS DATE: 06/25/2008

EFFECTIVE DATE: 07/01/2008

LEVEL OF USE: REFERENCE USE

QUALITY-RELATED

HISTORY OF REVISION/REVIEW

REV. NO.	REVISED PAGES		REASON FOR CURRENT REVISION
42	17-19 21,27,33,35, 94,99,105, 114,115, 117,118, 120,128,132	IC-53	BFN EPIP-1 revision 42 adjusts the information that supports EAL 1.1-G2 , 1.2-G and 1.5-S for changes resulting from engineering calculations that support Minimum RPV Flooding Pressures (MRFP), and Heat Capacity Temperature Limits. Revisions to these calculations were conducted for EOI Program Manual Revision 27 (U2C15). The revision to the EOI Program manual adjusts the EAL supportive information that is in compliance with the REP. EALs 2.3-A, 2.3-S1, 2.3-S2, 2.3-G1, 2.3-G2, 3.1-G, and 3.2-G were revised to adjust Unit 1 drywell radiation values to support the decision to not start Unit 1 at extended power up-rate (EPU). Calculations ND-N0090-930050 R11 and ND-N0090-930055 R12 support the conditions described above. The two calculations utilized to support the drywell radiation values are not a function of the Emergency Operating Instruction. This revision does not affect, alter or change the basis supporting the BFN TVA's standard emergency classification and action level scheme. Although this change does modify data and information utilized by existing EALs, the criteria established by NUREG 1.101 Rev. 3 (NUMARC/NESP 007 Revision 2) concerning the development of emergency action levels are not modified or changed. Specific EALs utilize information/data maintained through the implementation/maintenance of the Emergency Operating Instruction (EOI) procedures as well as specific calculations thus establishing thresholds used as entry conditions for emergency classifications. As calculations are revised based upon reactor parameters such as in this case, fuel specifications, the EAL threhold information must also be revised. This revision neither increases nor decreases the effectiveness of the REP. This revision simply adjusts data necessary to maintain the accuracy of applicable Emergency Action Levels.
43	21, 97, 34, 75, 127, 129, 188, 189	IC-54	Some pages were added which were intentionally left blank (and noted as so) to accommodate appropriate double sided printing and filing in procedure manuals. **EAL 1.2-A** - Wording of EAL enhanced to clarify intent of EAL. **EAL 7.3-U** - Wording revised to change "greater than" to "exceeds or is predicted to exceed". Additionally, the basis page for this EAL addressed the escalation to the Alert classification. This wording in the basis was also revised to change "greater than" to "exceeding or predicted to exceed". **EAL 7.3-A** - Wording in first condition changed from "greater than" to "exceeds or is predicted to exceed". Wording in second bullet of second condition changed from "Affecting equipment required for safe shutdown" to "Equipment required for safe shutdown is affected." **Table 3.1** – Removed from Table 3.1 the maximum safe operating temperature limit value for Core Spray B/D Pump Room High Humidity or Temp High specific for Unit 2 and Unit 3.

TABLE OF CONTENTS

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1.0 INTRODUCTION

1.1 Purpose

Provide guidance to the Shift Manager or Site Emergency Director (SED) for proper declaration and classification of emergencies and ensure emergency classifications are consistent with those used by state and local governments and the Nuclear Regulatory Commission (NRC).

The procedure applies to site events that constitute an emergency consistent with those site specific events outlined in NUMARC/NESP-007 August 1992. The Shift Manager and the SED are the only persons authorized to make the emergency classification determination.

2.0 REFERENCES

2.1 Industry Documents

A. NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants”
B. 10 CFR 50.47, Code of Federal Regulations
C. Reg Guide 1.101 Rev. 3, “Methodology for Development of Emergency Action Levels

2.2 Plant Instructions

A. TVA Radiological Emergency Plan
B. EPIP - 2, “Notification of Unusual Event”
C. EPIP - 3, “Alert”
D. EPIP - 4, “Site Area Emergency”
E. EPIP - 5, “General Emergency”
F. EPIP-16, “Termination and Recovery Procedure”

3.0 INSTRUCTION

3.1 Following plant events or transients review EPIP-1 Section II, 1.0 through 8.0 and determine if an event should be classified as an emergency.

NOTE

1. If an emergency action level for a higher classification was exceeded, but the present situation indicates a lower classification, the fact that the higher classification occurred shall be reported to the NRC and the CECC, if staffed, or ODS if the CECC is not staffed. The higher classification should not be declared.
2. If an emergency action level was met but the emergency has been totally resolved, the emergency class that was appropriate shall be reported to the ODS and the NRC but should not be declared.

3.1.1 EPIP-1 Section II, 1.0 through 8.0 captures events in eight major categories as listed on the event classification index.

3.1.2 Each emergency action level (EAL) in a category is given an alpha-numeric designator. The first numeric component of the EAL indicates the section followed by a numeric designator for the specific EAL within the section and an alpha numeric designator for the event class.

Example: 5.2-U

These designators provide for cross-reference between the specific EAL and the basis document which provides technical supporting information for the EAL and may aid the Shift Manager/SED in classifying events.

Curves, notes, or tables that support the EAL are located on the face adjacent page within the matrix section of the procedure and are identified within the event classification window on the information bar that precedes the designator. The information bar contains the appropriate indication to alert the user that a corresponding curve, note, or table applies to the EAL.

Curves, notes, or tables that contain **unit specific** information will also be identified within the event classification window by the letter "US" located at the end of the EAL information bar. This information should alert the user that the corresponding curve, note, or table contains unit specific information.

Example

5.2-U	CURVE	NOTE	TABLE	US

3.2 If the event is determined to be one of the four emergency classifications, the Shift Manager assumes the responsibility of SED until relieved by the Plant Manager or designee.

3.2.1 Implement one of the following procedures as applicable:

EPIP-2	Notification of Unusual Event
EPIP-3	Alert
EPIP-4	Site Area Emergency
EPIP-5	General Emergency

3.2.2 Continue to review the emergency conditions in the event classification matrix and escalate, terminate, or implement recovery as appropriate. Refer to EPIP-16 for termination or recovery.

3.3 If the event is determined not to be one of the four event classifications, continue to monitor plant conditions for possible changes that could result in reaching an event classification.

LAST TEXT

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4.0 GLOSSARY of ABBREVIATIONS, ACRONYMS, AND DEFINITIONS

The following is a list of terms and phrases found in EPIP-1. Each term or phrase is provided with a meaning, to ensure consistent use and understanding.

TERM/PHRASE	**MEANING/DEFINITION**
ADS	Automatic Depressurization System
AOI	Abnormal Operating Instruction
Alert	Events are in process or have occurred which involve an actual or potential substantial degradation of the level of safety of the plant or a security event that involve probably 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.
ARI	Alternate Rod Insertion
ARM	Area Radiation Monitor
ARP	Alarm Response Procedure
ATWS	Anticipated Transient Without Scram
Auto	Automatic
Bomb	An explosive device
BWR	Boiling Water Reactor
Can/Cannot be determined	The current value or status of an identified parameter relative to that specified in the instruction can/cannot be ascertained using all available indications (direct and indirect, singly or in combination).
Can/Cannot be Maintained Above/Below	The value of the identified parameter(s) is/is not able to be kept above/below specified limits. This definition includes making an evaluation that considers both current and future system performance in relation to the current value and trend of the parameter(s). "Cannot" does not imply that the actual value of the parameter must first exceed the specified limit.
Can/Cannot be Restored Above/Below	The value of the identified parameter(s) is/is not able to be returned to above/below specified limits within a reasonable time after having exceeded the specified limits. This determination includes making an evaluation that considers both current and future system performance in relation to the current value and trend of the parameter(s).

TERM/PHRASE	MEANING/DEFINITION
CAD	Containment Atmosphere Dilution
CAS	Central Alarm Station
CDE	Committed Dose Equivalent
CECC	Central Emergency Control Center
Ci	Curie
Civil Disturbance	A group of 20 or more persons violently protesting station operations or activities at the site.
cm^3	Cubic Centimeters
Confinement Boundary	Spent Fuel Storage Cask CONFINEMENT BOUNDARY consisting of the MPC shell, bottom base plate, MPC lid (including the vent and drain port cover plates), MPC closure ring, and associated welds.
CS	Core Spray
deg	Degrees
DG	Diesel Generator
Drywell	The upper portion of the Primary Containment which encloses the Reactor Pressure Vessel.
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
ECL	Effluent Concentration Limit
EOI	Emergency Operating Instruction
EPA	Environmental Protection Agency
EPIP	Emergency Plan Implementing Procedure
EQ	Environmental Qualification

TERM/PHRASE	MEANING/DEFINITION
Event	Assessment of an EVENT commences when recognition is made that one or more of the conditions associated with the event exists. Implicit in this definition is the need for timely assessment, i.e. within 15 minutes.
Explosion	A rapid, violent, unconfined combustion or a catastrophic failure of pressurized equipment that imparts energy of sufficient force to potentially damage permanent structures required for safe operation.
F	Fahrenheit
Fire	Combustion characterized by heat and light. Sources of smoke such as slipping drive belts or overheated electrical components do not constitute fires. Observation of flame is preferred but is not required if large quantities of smoke and heat are observed.
Flammable Gas	Combustible gasses maintained at concentrations less than the lower explosive limit. Will not explode due to ignition.
GOI	General Operating Instruction
General Emergency	Events are in process 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.
gm	Gram
HCTL	Heat Capacity Temperature Limit
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 a nuclear power plant 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 be acts of civil disobedience or felonious acts that are not part of a concerted attack on the nuclear power plant. Non-terrorism based EALs should be used to address such activities, (e.g. violent acts between individuals in the owner controlled area).

TERM/PHRASE	MEANING/DEFINITION
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.
HPCI	High Pressure Coolant Injection
HR	Hour
IN	Inches
ISFSI	Independent Spent Fuel Storage Installation
KV	Kilovolt
Large framed aircraft	A large aircraft with the potential for causing significant damage to the plant; may be referred to as an airliner.
LCO	Limiting Condition for Operation
LOCA	Loss Of Coolant Accident
LPCI	Low Pressure Coolant Injection
MRFP	Minimum RPV Flooding Pressure
MCUTL	Maximum Core Uncovery Time Limit
MIN	Minute

Modes of Operation

Mode	Title	Reactor Mode Switch Position	Avg. Reactor Coolant Temperature (^{0}F)
1	Power Operation	Run	NA
2	Startup	Refuel[a] or Startup/Hot Standby	NA
3	Hot Shutdown[a]	Shutdown	> 212
4	Cold Shutdown[a]	Shutdown	$\leq$ 212
5	Refueling[b]	Shutdown or Refuel	NA

(a) All reactor vessel head closure bolts fully tensioned.
(b) One or more reactor vessel head closure bolts less that fully tensioned.

MPC	Multi-Purpose Canister (part of ISFSI)

TERM/PHRASE	MEANING/DEFINITION
MPH	Miles per Hour
mrem	Millirem
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
MSRV	Main Steam Relief Valve
NESP	National Environmental Studies Project
Notification of Unusual Event	Events are in process 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.
NUMARC	Nuclear Management and Resources Council
OCA	Owner Controlled Area
ODS	Operations Duty Specialist
OI	Operating Instruction
OSC	Operations Support Center
PA	Protected Area
PAR	Protective Action Recommendation
PCIS	Primary Containment Isolation System
Primary Containment	The drywell, the vent system, and the suppression chamber.
Primary System	Primary systems comprise the pipes, valves and other equipment connected to the RPV such that a reduction in RPV pressure will affect a decrease in the flow of steam or water being discharged through an unisolable break in the system.

TERM/PHRASE	MEANING/DEFINITION
Projectile	An object ejected, thrown, or launched towards a plant structure. The source of a projectile may be offsite or onsite. Damage is sufficient to cause concern regarding the integrity of the affected structure or the operability or reliability of safety equipment contained therein.
Protected Area	All areas within the security protected area fence.
PSIG	Pounds Per Square Inch Gauge
R	Rad
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
REP	Radiological Emergency Plan
RHR	Residual Heat Removal
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
Sabotage	Deliberate damage, misalignment, misoperation of plant equipment with the intent to render equipment inoperable.
SAMG	Severe Accident Management Guideline
SEC	Second
Secondary Containment	The spaces immediately adjacent to or surrounding, the primary containment from which the Reactor Building Ventilation System and the Standby Gas Treatment System provides a filtered elevated release.
SED	Site Emergency Director
SGTS	Standby Gas Treatment System
Significant Transient	An unplanned event involving one or more of the following: (1) Automatic turbine runback greater than 25% thermal reactor power or (2) Electrical load reduction greater than 25% full electrical load, or (3) Thermal power oscillations greater than 10%, or (4) Reactor scram, or (5) Valid ECCS initiation.

TERM/PHRASE	MEANING/DEFINITION
SI	Surveillance Instruction
Site Area Emergency	Events are in process 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 thereof 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 site boundary.
Site Boundary	That line beyond which the land or property is not owned, leased, or otherwise controlled by TVA.
Subcritical	Reactor power below the heating range and not trending upward.
Suppression Pool	The water volume contained in the suppression chamber intended to condense steam from an MSRV actuation or a primary system break inside the drywell, and provide an ECCS system injection water source.
Suppression Chamber	The structure enclosing the suppression pool water and the atmosphere above it.
TAF	Top of Active Fuel
TEDE	Total Effective Dose Equivalent
Torus	The lower portion of the primary containment which encloses the suppression pool. Equivalent to the suppression chamber.
Toxic Gas	A gas that is dangerous to life or limb by reason of inhalation or skin contact.
TSC	Technical Support Center
Valid	An indication, report, or condition is considered to be valid when it is conclusively verified by redundant indicators or actual observation by plant personnel.
Visible Damage	Damage to equipment that is readily observable without measurements, testing, or analysis. Damage is sufficient enough to cause concern regarding the continued operability or reliability of affected safety structure, system, or component.

TERM/PHRASE	MEANING/DEFINITION
Vital Area	An area that contains equipment necessary for the safe operations and shutdown of the plant.
WRGERMS	Wide Range Gaseous Effluent Radiation Monitoring System
yr	Year

5.0 EVENT CLASSIFICATION INDEX

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REACTOR
1.0

NOTES

1.1-U1/1.1-A1 — Applicable when the Reactor Head is removed and the Reactor Cavity is flooded.

1.1-S1 — Applicable in Mode 5 when the Reactor Head is installed.

1.1-G2 — The reactor will remain subcritical under all conditions without boron when:

- Unit 1: All control rods are inserted to or beyond position 02.
  Unit 2: Any 19 control rods are inserted to position 02, with all other control rods fully inserted.
  Unit 3: Any 19 control rods are inserted to position 02, with all other control rods fully inserted.
- All control rods except one are inserted to or beyond position 00.
- Determined by Reactor Engineering.

CURVES/TABLES:

TABLE 1.1 - G2
MINIMUM ALTERNATE RPV FLOODING PRESS (MARFP)

NUMBER OF OPEN MSRVs	MARFP (PSIG)
6 or More	190
5	230
4	290

WATER LEVEL

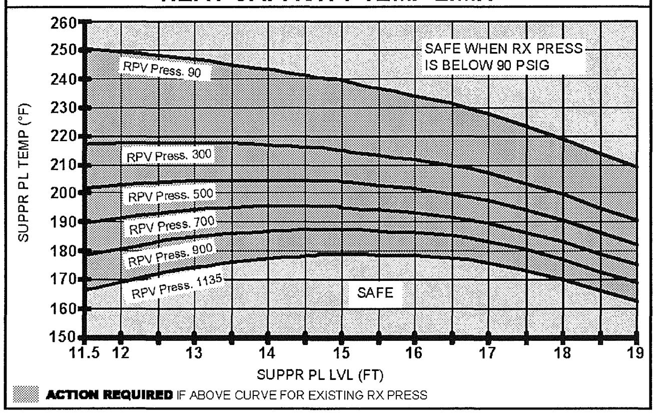
Description	Description	
1.1-U1 | **NOTE** Uncontrolled water level decrease in Reactor Cavity with irradiated fuel assemblies expected to remain covered by water. OPERATING CONDITION: Mode 5	**1.1-U2** Uncontrolled water level decrease in Spent Fuel Pool with irradiated fuel assemblies expected to remain covered by water. OPERATING CONDITION ALL	UNUSUAL EVENT
1.1-A1 | **NOTE** Uncontrolled water level decrease in Reactor Cavity expected to result in irradiated fuel assemblies being uncovered. OPERATING CONDITION: Mode 5	**1.1-A2** Uncontrolled water level decrease in Spent Fuel Storage Pool expected to result in irradiated fuel assemblies being uncovered. OPERATING CONDITION: ALL	ALERT
1.1-S1 | **NOTE** Reactor water level can NOT be maintained above -162 inches. (TAF) OPERATING CONDITION: ALL	**1.1-S2** Reactor water level can NOT be determined. OPERATING CONDITION: Mode 1 or 2 or 3	SITE EMERGENCY
1.1-G1 Reactor water level can NOT be restored and maintained above -180 inches. OPERATING CONDITION: Mode 1 or 2 or 3	**1.1-G2** | **NOTE** | **TABLE** | **US** Reactor water level can NOT be determined **AND** Either of the following exists: • The reactor will remain subcritical without boron under all conditions, and ➤ Less than 4 MSRVs can be opened, or ➤ Reactor pressure can NOT be restored and maintained above Suppression Chamber pressure by at least ❖ UNIT 1 – 90 psi ❖ UNIT 2 – 80 psi ❖ UNIT 3 – 70 psi • It has NOT been determined that the reactor will remain subcritical without boron under all conditions and unable to restore and maintain MARFP in Table 1.1-G2. OPERATING CONDITION: Mode 1 or 2 or 3	GENERAL EMERGENCY

NOTES

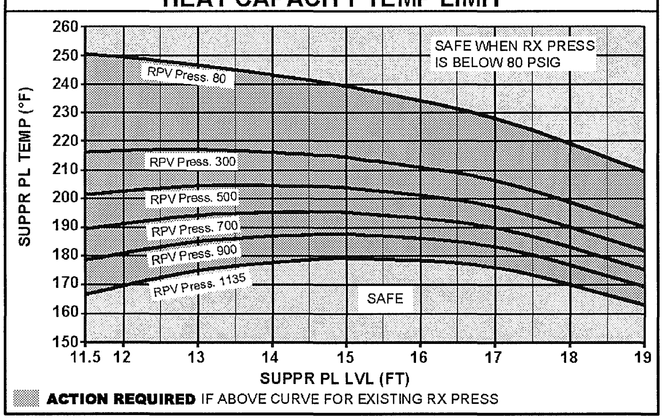
1.2 Subcritical is defined as reactor power below the heating range and not trending upward.

CURVES/TABLES:

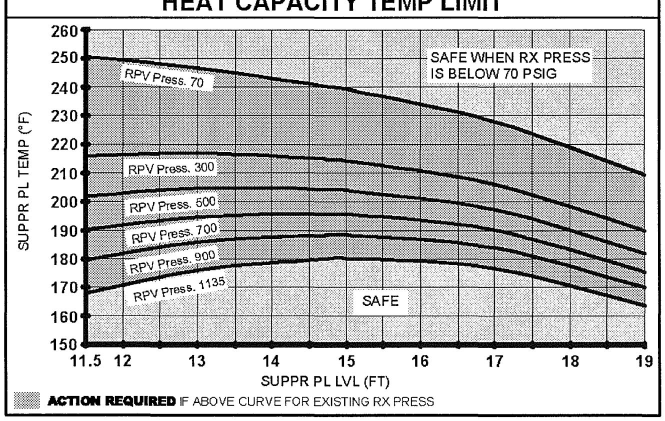
UNIT 1
CURVE 1.2-G
HEAT CAPACITY TEMP LIMIT



UNIT 2
CURVE 1.2-G
HEAT CAPACITY TEMP LIMIT



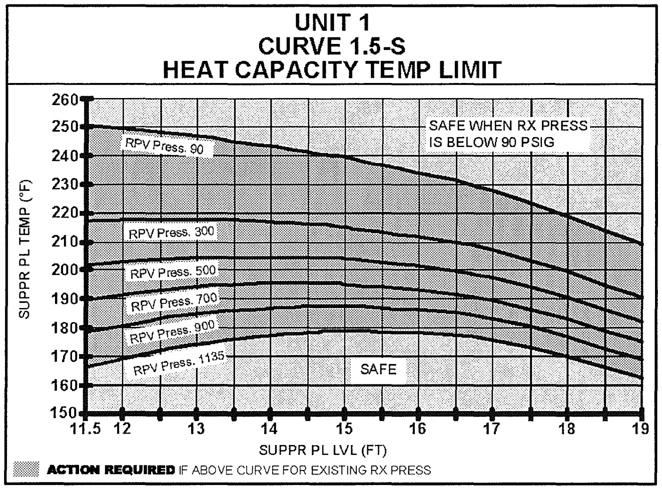
UNIT 3
CURVE 1.2-G
HEAT CAPACITY TEMP LIMIT

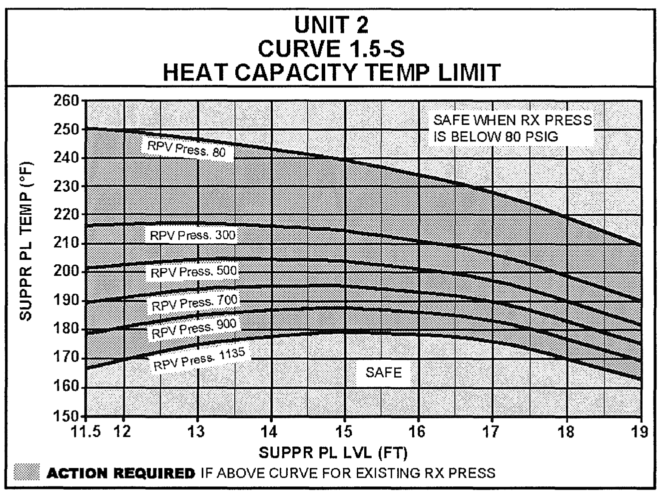


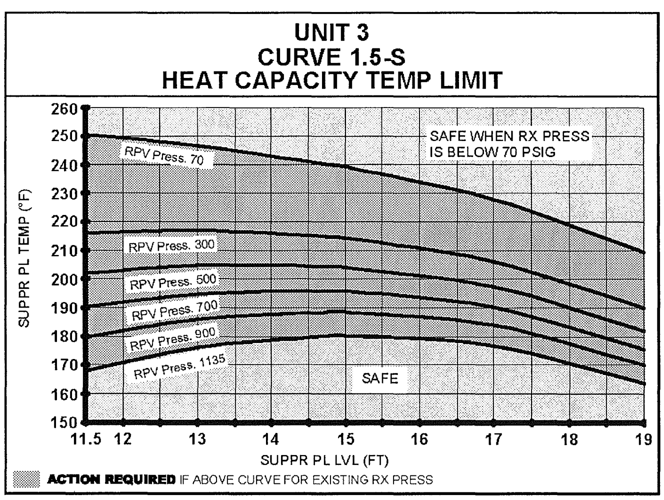
SCRAM FAILURE	REACTOR COOLANT ACTIVITY	
Description	**Description**	
	1.3-U	**UNUSUAL EVENT**
	Reactor coolant activity exceeds 26 µCi/gm dose equivalent I-131 (Technical Specification Limits) as determined by chemistry sample. OPERATING CONDITION ALL	
1.2-A · **NOTE**	**1.3-A**	**ALERT**
Failure of RPS automatic scram functions to bring the reactor subcritical **AND** Manual scram or ARI (automatic or manual) was successful. OPERATING CONDITION: Mode 1 or 2	Reactor coolant activity exceeds 300 µCi/gm dose equivalent Iodine-131 as determined by chemistry sample. OPERATING CONDITION: Mode 1 or 2 or 3	
1.2-S · **NOTE**		**SITE EMERGENCY**
Failure of automatic scram, manual scram, and ARI to bring the reactor subcritical. OPERATING CONDITION: Mode 1		
1.2-G · **CURVE** · **US**		**GENERAL EMERGENCY**
Failure of automatic scram, manual scram, and ARI. Reactor power is above 3% **AND** Either of the following conditions exists: • Suppression Pool temp exceeds HCTL. Refer to Curve 1.2-G. • Reactor water level can NOT be restored and maintained at or above -180 inches. OPERATING CONDITION: Mode 1 or 2		

NOTES

CURVES/TABLES:







	MSL / OFFGAS RADIATION	LOSS OF DECAY HEAT REMOVAL
	Description	Description
UNUSUAL EVENT	**1.4-U** Valid MAIN STEAM LINE RADIATION HIGH-HIGH alarm, RA-90-135C **OR** Valid OG PRETREATMENT RADIATION HIGH alarm, RA-90-157A. OPERATING CONDITION: Mode 1 or 2 or 3	
ALERT		**1.5-A** Reactor moderator temperature can NOT be maintained below 212^0 F whenever Technical Specifications require Mode 4 conditions or during operations in Mode 5. OPERATING CONDITION: Mode 4 or 5
SITE EMERGENCY		**1.5-S** | **CURVE** | **US** Suppression Pool temperature, level and RPV pressure can NOT be maintained in the safe area of Curve 1.5-S. OPERATING CONDITION: Mode 1 or 2 or 3
GENERAL EMERGENCY		

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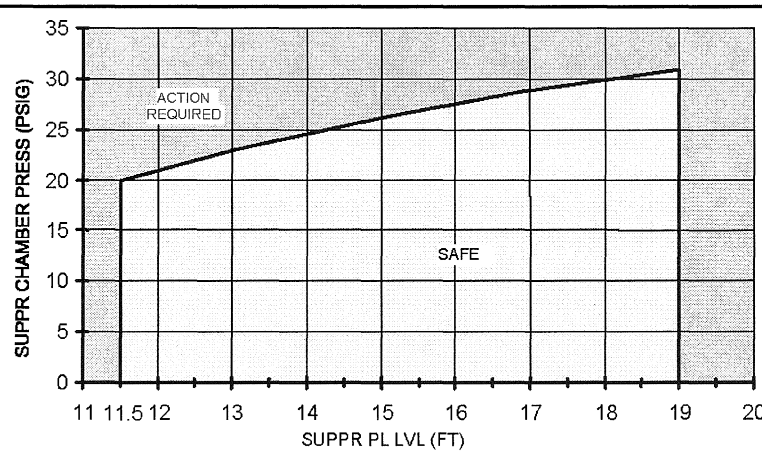
PRIMARY CONTAINMENT 2.0

NOTES

CURVES/TABLES:

TABLE 2.1-A INDICATIONS OF PRIMARY SYSTEM LEAKAGE INTO PRIMARY CONTAINMENT
Primary Containment Pressure High Alarm
Drywell Floor Drain Sump Pump Excessive Operation
Drywell CAM Activity Increasing
Drywell Temperature High Alarm
Chemistry Sample Radionuclide Comparison To Reactor Water

CURVE 2.1-S
PRESS SUPPR PRESS



PRIMARY CONTAINMENT PRESSURE Description	PRIMARY CONTAINMENT HYDROGEN Description	
		UNUSUAL EVENT
2.1-A **TABLE** Drywell pressure at or above 2.45 psig **AND** Indication of Primary System leakage into Primary Containment. Refer to Table 2.1-A. OPERATING CONDITION: Mode 1 or 2 or 3		ALERT
2.1-S **CURVE** Suppression Chamber pressure can NOT be maintained in the safe area of Curve 2.1-S. OPERATING CONDITION: Mode 1 or 2 or 3	**2.2-S** Drywell or Suppression Chamber hydrogen concentration at or above 4% **AND** Drywell or Suppression Chamber oxygen concentration at or above 5%. OPERATING CONDITION: Mode 1 or 2 or 3	SITE EMERGENCY
2.1-G Suppression Chamber pressure can NOT be maintained below 55 psig. OPERATING CONDITION: Mode 1 or 2 or 3	**2.2-G** Drywell or Suppression Chamber hydrogen concentration at or above 6% **AND** Drywell or Suppression Chamber oxygen concentration at or above 5%. OPERATING CONDITION: Mode 1 or 2 or 3	GENERAL EMERGENCY

NOTES

CURVES/TABLES:

TABLE 2.3-A/2.3-S2 DRYWELL RADIATION LEVELS WITH RCS BARRIER INTACT INSIDE PRIMARY CONTAINMENT					
UNIT 1		UNIT 2		UNIT 3	
RAD MONITOR	R/HR	RAD MONITOR	R/HR	RAD MONITOR	R/HR
1-RE-90-272A	196	2-RE-90-272A	642	3-RE-90-272A	196
1-RE-90-273A	297	2-RE-90-273A	297	3-RE-90-273A	297

TABLE 2.3-S1/2.3-G2 DRYWELL RADIATION LEVELS WITH RCS BARRIER NOT INTACT INSIDE PRIMARY CONTAINMENT					
UNIT 1		UNIT 2		UNIT 3	
RAD MONITOR	R/HR	RAD MONITOR	R/HR	RAD MONITOR	R/HR
1-RE-90-272A	2981	2-RE-90-272A	2263	3-RE-90-272A	2981
1-RE-90-273A	2960	2-RE-90-273A	2960	3-RE-90-273A	2960

TABLE 2.3-G1 DRYWELL RADIATION LEVELS WITH RCS BARRIER NOT INTACT INSIDE PRIMARY CONTAINMENT					
UNIT 1		UNIT 2		UNIT 3	
RAD MONITOR	R/HR	RAD MONITOR	R/HR	RAD MONITOR	R/HR
1-RE-90-272A	90091	2-RE-90-272A	68405	3-RE-90-272A	90091
1-RE-90-273A	89450	2-RE-90-273A	89450	3-RE-90-273A	89450

TABLE 2.3/2.5-U INDICATIONS OF LOSS OF PRIMARY CONTAINMENT
Unexplained Loss Of Containment Pressure
Exceeding SI-4.7.A.2.a Limits
Inability To Isolate Any Line Exiting Containment When Isolation Is Required
Venting Irrespective Of Offsite Release Rates Per EOIs/SAMGs

DRYWELL RADIATION

<table>
<tr><th colspan="5">Description</th><th colspan="5">Description</th><th></th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td rowspan="2">UNUSUAL EVENT</td></tr>
<tr><td colspan="5"></td><td colspan="5"></td></tr>
<tr><td>2.3-A</td><td></td><td></td><td>TABLE</td><td>US</td><td></td><td></td><td></td><td></td><td></td><td rowspan="2">ALERT</td></tr>
<tr><td colspan="5">Drywell radiation levels at or above the values listed in Table 2.3-A/2.3-S2, with the RCS barrier intact inside Primary Containment.

OPERATING CONDITION:
Mode 1 or 2 or 3</td><td colspan="5"></td></tr>
<tr><td>2.3-S1</td><td></td><td></td><td>TABLE</td><td>US</td><td>2.3-S2</td><td></td><td></td><td>TABLE</td><td>US</td><td rowspan="2">SITE EMERGENCY</td></tr>
<tr><td colspan="5">Drywell radiation levels at or above the values listed in Table 2.3-S1/2.3-G2 with the RCS barrier NOT intact inside Primary Containment.

OPERATING CONDITION:
Mode 1 or 2 or 3</td><td colspan="5">Drywell radiation levels at or above the values listed in Table 2.3-A/2.3-S2, with the RCS barrier intact inside Primary Containment,
AND
Either of the following exists:
• Indications of loss of Primary Containment. Refer to Table 2.3/2.5-U.
• Primary Containment integrity can NOT be maintained.

OPERATING CONDITION:
Mode 1 or 2 or 3</td></tr>
<tr><td>2.3-G1</td><td></td><td></td><td>TABLE</td><td>US</td><td>2.3-G2</td><td></td><td></td><td>TABLE</td><td>US</td><td rowspan="2">GENERAL EMERGENCY</td></tr>
<tr><td colspan="5">Drywell radiation levels at or above the values listed in Table 2.3-G1 with the RCS barrier NOT intact inside Primary Containment.

OPERATING CONDITION:
Mode 1 or 2 or 3</td><td colspan="5">Drywell radiation levels at or above the values listed in Table 2.3-S1/2.3-G2 with the RCS barrier NOT intact inside Primary Containment,
AND
Either of the following exists:
• Indications of loss of Primary Containment. Refer to Table 2.3/2.5-U.
• Primary Containment integrity can NOT be maintained.

OPERATING CONDITION:
Mode 1 or 2 or 3</td></tr>
</table>

NOTES

CURVES/TABLES:

TABLE 2.3/2.5-U INDICATIONS OF LOSS OF PRIMARY CONTAINMENT
Unexplained Loss Of Containment Pressure
Exceeding SI-4.7.A.2.a Limits
Inability To Isolate Any Line Exiting Containment When Isolation Is Required
Venting Irrespective Of Offsite Release Rates Per EOIs/SAMGs

DRYWELL INTERNAL LEAKAGE	LOSS OF PRIMARY CONTAINMENT	
Description	Description	
2.4-U Drywell unidentified leakage exceeds 10 gpm **OR** Drywell identified leakage exceeds 40 gpm. OPERATING CONDITION: Mode 1 or 2 or 3	**2.5-U** TABLE Inability to maintain Primary Containment pressure boundary. Refer to Table 2.3/2.5-U. OPERATING CONDITION: Mode 1 or 2 or 3	UNUSUAL EVENT
2.4-A Drywell unidentified leakage exceeds 50 gpm. OPERATING CONDITION: Mode 1 or 2 or 3		ALERT
		SITE EMERGENCY
		GENERAL EMERGENCY

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SECONDARY CONTAINMENT 3.0

NOTES

CURVES/TABLES:

TABLE 3.1
MAXIMUM SAFE OPERATING AREA TEMPERATURE LIMITS

AREA	APPLICABLE PANEL 9-21 TEMPERATURE ELEMENTS (UNLESS OTHERWISE NOTED)	MAX SAFE OPERATING VALUE °F		
		UNIT 1	UNIT 2	UNIT 3
RHR A/C Pump Room	74-95A	215	150	155
RHR B/D Pump Room	74-95B	150	210	215
HPCI Turbine Area	73-55A	275	270	270
CS A/C Pump and RCIC Turbine Area	71-41A	190	190	190
RCIC Steam Supply Area	71-41B, 41C, 41D	195	200	250
HPCI Steam Supply Area	73-55B, 55C, 55D	245	240	240
RHR A/C Pump Supply Area	74-95H	245	240	240
RHR B/D Pump Supply Area	74-95G	190	240	240
Main Steam Line Leak Detection High	(XA-55-3D-24) Panel 9-3 TIS-1-60A	315	315	315
RHR Valve Room	74-95E	175	170	175
RWCU Isol Logic Channel A/B Temp High	(XA-55-5B-32/33) Panel 9-5 69-835A, B, C, D Aux Inst Room	175	170	175
RWCU Outbd Isol Vlv Area	69-29F	220	220	220
RWCU Hx Area	69-29G	220	220	220
RWCU Hx Exh Duct	69-29H	220	220	220
RWCU Recirc Pump A Area	69-29D	215	215	215
RWCU Recirc Pump B Area	69-29E	215	215	215
RHR A/C Hx Room	74-95C	210	195	200
RHR B/D Hx Room	74-95D	210	195	200
FPC Hx Area	74-95F	160	155	155

TABLE 3.1-G/3.2-G
INDICATIONS OF POTENTIAL OR SIGNIFICANT FUEL CLADDING FAILURE WITH RCS BARRIER INTACT INSIDE PRIMARY CONTAINMENT

UNIT 1 DRYWELL RADIATION		UNIT 2 DRYWELL RADIATION		UNIT 3 DRYWELL RADIATION	
1-RE-90-272A	≥ 196 R/HR	2-RE-90-272A	≥ 642 R/HR	3-RE-90-272A	≥ 196 R/HR
1-RE-90-273A	≥ 297 R/HR	2-RE-90-273A	≥ 297 R/HR	3-RE-90-273A	≥ 297 R/HR
Reactor Coolant Activity ≥ 300 μCi/gm Dose Equivalent Iodine 131		Reactor Coolant Activity ≥ 300 μCi/gm Dose Equivalent Iodine 131		Reactor Coolant Activity ≥ 300 μCi/gm Dose Equivalent Iodine 131	

SECONDARY CONTAINMENT TEMPERATURE

Description

UNUSUAL EVENT

ALERT

SITE EMERGENCY

3.1-S			TABLE	US

An unisolable Primary System leak is discharging into Secondary Containment

AND

Any area temperature exceeds the Maximum Safe Operating Temperature limit listed in Table 3.1.

OPERATING CONDITION:
Mode 1 or 2 or 3

GENERAL EMERGENCY

3.1-G			TABLE	US

An unisolable Primary System leak is discharging into Secondary Containment

AND

Any area temperature exceeds the Maximum Safe Operating Temperature limit listed in Table 3.1

AND

Any indication of potential or significant fuel cladding failure exists. Refer to Table 3.1-G/3.2-G with RCS Barrier intact inside Primary Containment.

OPERATING CONDITION
Mode 1 or 2 or 3

NOTES

CURVES/TABLES:

TABLE 3.2 MAXIMUM SAFE OPERATING AREA RADIATION LIMITS		
AREA	**RAD MONITOR**	**MAX SAFE VALUE MR/HR**
RHR West Room	90-25A	1000
RHR East Room	90-28A	1000
HPCI Room	90-24A	1000
CS/RCIC Room	90-26A	1000
Core Spray Room	90-27A	1000
Suppr Pool Area	90-29A	1000
CRD-HCU West Area	90-20A	1000
CRD-HCU East Area	90-21A	1000
TIP Drive Area	90-23A	1000
North RWCU System Area	90-13A	1000
South RWCU System Area	90-14A	1000
RWCU System Area	90-9A	1000
MG Set Area	90-4A	1000
Fuel Pool Area	90-1A	1000
Service Flr Area	90-2A	1000
New Fuel Storage	90-3A	1000

TABLE 3.1-G/3.2-G INDICATIONS OF POTENTIAL OR SIGNIFICANT FUEL CLADDING FAILURE WITH RCS BARRIER INTACT INSIDE PRIMARY CONTAINMENT					
UNIT 1 DRYWELL RADIATION		**UNIT 2 DRYWELL RADIATION**		**UNIT 3 DRYWELL RADIATION**	
1-RE-90-272A	≥ 196 R/HR	2-RE-90-272A	≥ 642 R/HR	3-RE-90-272A	≥ 196 R/HR
1-RE-90-273A	≥ 297 R/HR	2-RE-90-273A	≥ 297 R/HR	3-RE-90-273A	≥ 297 R/HR
Reactor Coolant Activity ≥ 300 μCi/gm Dose Equivalent Iodine 131		Reactor Coolant Activity ≥ 300 μCi/gm Dose Equivalent Iodine 131		Reactor Coolant Activity ≥ 300 μCi/gm Dose Equivalent Iodine 131	

SECONDARY CONTAINMENT RADIATION

Description

UNUSUAL EVENT

ALERT

3.2-A				

Any of the following high radiation alarms on Panel 9-3:

- RA-90-1A, Fuel Pool Floor Alarm
- RA-90-250A, Reactor, Turbine, Refuel Exhaust
- RA-90-142A, Reactor Refuel Exhaust
- RA-90-140A, Refueling Zone Exhaust

AND

Confirmation by Refuel Floor personnel that irradiated fuel damage may have occurred.

OPERATING CONDITION:
ALL

SITE EMERGENCY

3.2-S			TABLE	

An unisolable Primary System leak is discharging into Secondary Containment

AND

Any area radiation level at or above the Maximum Safe Operating Area radiation limit listed in Table 3.2.

OPERATING CONDITION:
Mode 1 or 2 or 3

GENERAL EMERGENCY

3.2-G			TABLE	US

An unisolable Primary System leak is discharging into Secondary Containment

AND

Any area radiation level at or above the Maximum Safe Operating Area radiation limit listed in Table 3.2.

AND

Any indication of potential or significant fuel cladding failure exists. Refer to Table 3.1-G/3.2-G with RCS Barrier intact inside Primary Containment.

OPERATING CONDITION
Mode 1 or 2 or 3

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RADIOACTIVITY RELEASES 4.0

NOTES

4.1-U Prior to making this emergency classification based upon the WRGERMS indication, assess the release by either of the following:

1. Actual field measurements exceed the limits in table 4.1-U
2. 0-SI 4.8.B.1.a.1 release fraction exceeds 2.0

If neither assessment can be conducted within 60 minutes then the declaration must be made on the valid WRGERMS reading.

4.1-A Prior to making this emergency classification based upon the WRGERMS indication, assess the release by either of the following:

1. Actual field measurements exceed the limits in table 4.1-A
2. 0-SI 4.8.B.1.a.1 release fraction exceeds 200

If neither assessment can be conducted within 15 minutes then the declaration must be made on the valid WRGERMS reading.

4.1-S Prior to making this emergency classification based upon the gaseous release rate indication, assess the release by either of the following methods:

1. Actual field measurements exceed the limits in table 4.1-S.
2. Projected or actual dose assessments exceed 100 mrem TEDE or 500 mrem CDE.

If neither assessment can be conducted within 15 minutes then the declaration must be made based on the valid WRGERMS reading.

4.1-G Prior to making this emergency classification based upon the gaseous release rate indication, assess the release by either of the following methods:

1. Actual field measurements exceed the limits in table 4.1-G.
2. Projected or actual dose assessments exceed 1000 mrem TEDE or 5000 mrem CDE.

If neither assessment can be conducted within 15 minutes then the declaration must be made based on the valid WRGERMS reading.

CURVES/TABLES:

Table 4.1-U
RELEASE LIMITS FOR UNUSUAL EVENT

TYPE	MONITORING METHOD	LIMIT	DURATION
Gaseous Release Rate	Stack Noble Gas (WRGERMS)	2.88×10^{7} µCi/sec	1 Hour
Gaseous Release Rate	0-SI 4.8.B.1.a.1	Release Fraction 2.0	1 Hour
Site Boundary Radiation Reading	Field Assessment Team	0.10 MREM/HR Gamma	1 Hour

Table 4.1-A
RELEASE LIMITS FOR ALERT

TYPE	MONITORING METHOD	LIMIT	DURATION
Gaseous Release Rate	Stack Noble Gas (WRGERMS)	2.88×10^{9} µCi/sec	15 Minutes
Gaseous Release Rate	0-SI 4.8.B.1.a.1	Release Fraction 200	15 Minutes
Site Boundary Radiation Reading	Field Assessment Team	10 MREM/HR Gamma	15 Minutes

Table 4.1-S
RELEASE LIMITS FOR SITE AREA EMERGENCY

TYPE	MONITORING METHOD	LIMIT	DURATION
Gaseous Release Rate	Stack Noble Gas (WRGERMS)	5.9×10^{9} µCi/sec	15 Minutes
Site Boundary Radiation Reading	Field Assessment Team	100 MREM/HR Gamma	1 Hour
Site Boundary Iodine-131	Field Assessment Team	3.9×10^{-7} µCI /cm^{3}	1 Hour

Table 4.1-G
RELEASE LIMITS FOR GENERAL EMERGENCY

TYPE	MONITORING METHOD	LIMIT	DURATION
Gaseous Release Rate	Stack Noble Gas (WRGERMS)	5.9×10^{10} µCi/sec	15 Minutes
Site Boundary Radiation Reading	Field Assessment Team	1000 MREM/HR Gamma	1 Hour
Site Boundary Iodine-131	Field Assessment Team	3.9×10^{-6} µCI / cm^{3}	1 Hour

GASEOUS EFFLUENT

Description

4.1-U		NOTE	TABLE	

Gaseous release exceeds ANY limit and duration in Table 4.1-U.

OPERATING CONDITION:
ALL

UNUSUAL EVENT

4.1-A		NOTE	TABLE	

Gaseous release exceeds ANY limit and duration in Table 4.1-A.

OPERATING CONDITION:
ALL

ALERT

4.1-S		NOTE	TABLE	

EITHER of the following conditions exists:

- Gaseous release exceeds or is expected to exceed ANY limit and duration in Table 4.1-S.
- Dose assessment indicates actual or projected dose consequences above 100 mrem TEDE or 500 mrem thyroid CDE.

OPERATING CONDITION:
ALL

SITE EMERGENCY

4.1-G		NOTE	TABLE	

EITHER of the following conditions exists:

- Gaseous release exceeds or is expected to exceed ANY limit and duration in Table 4.1-G.
- Dose assessment indicates actual or projected dose consequences above 1000 mrem TEDE or 5000 mrem thyroid CDE.

OPERATING CONDITION
ALL

GENERAL EMERGENCY

NOTES

CURVES/TABLES: