Memorandum: To File Date: 12/1/00

From: M. E. Murphy, Chief Examiner

Subject: River Bend Station Comments on the Written Examination given October 27, 2000

The attached are the comments presented by the licensee for the Subject examination. The comments are accepted for Questions 19, 80, 86 and 95. The comment for Question 7 is modified as follows: Accept answer 'C' only.

1) QUESTION - RO 7:

Following a small break LOCA, indicated wide range reactor level is 20" and slowly increasing due to RCIC injection from the CST. Other plant parameters are as follows:

- RPV pressure	550 psig
- Suppression pool temp	140 deg. F
- Containment pressure	4.0 psig

The MINIMUM suppression pool level which will assure adequate heat capacity is:

a. 15.4 ft

b. 19.6 ft

c. 17 ft

d. 21.25 ft

ANSWER: A

REFERENCE: HLO-514 8, OBJ.#*8, EOP-0002, HCTL Curve,

NRC KA:	RO:	SRO:
295026 EK2.06	3.5	3.7
295026 EK3.01	3.8	4.1

QUESTION - RO 7: (Continued)

RECOMMENDATION:

Accept both answers (a) and (c).

JUSTIFICATION:

One of the factors used in the derivation of Heat Capacity Temperature Limit (HCTL) and the Pressure Suppression Pressure Limit (PSP) curves is the depressurization of the RPV. In both cases the heat capacity of the suppression pool to handle the depressurization is evaluated.

The intent of the question was to test knowledge of the HCTL curve as shown by the stem of the question. Answer (a) *"15.4 ft"* is correct when the Heat Capacity Temperature Limit (HCTL) curve is reviewed against the given parameters.

If the Pressure Suppression Pressure (PSP) curve is utilized, then the correct answer is (c) *"17 ft"*. The suppression pool level that is needed to support 4.0 psig in the containment (per the PSP) is a minimum of 15.5 ft therefore answer (a) *"15.4 ft"* would not satisfy this.

Reference:

EPSTG*0002 Appendix A Heat Capacity Temperature Limit and Pressure Suppression Pressure curves.

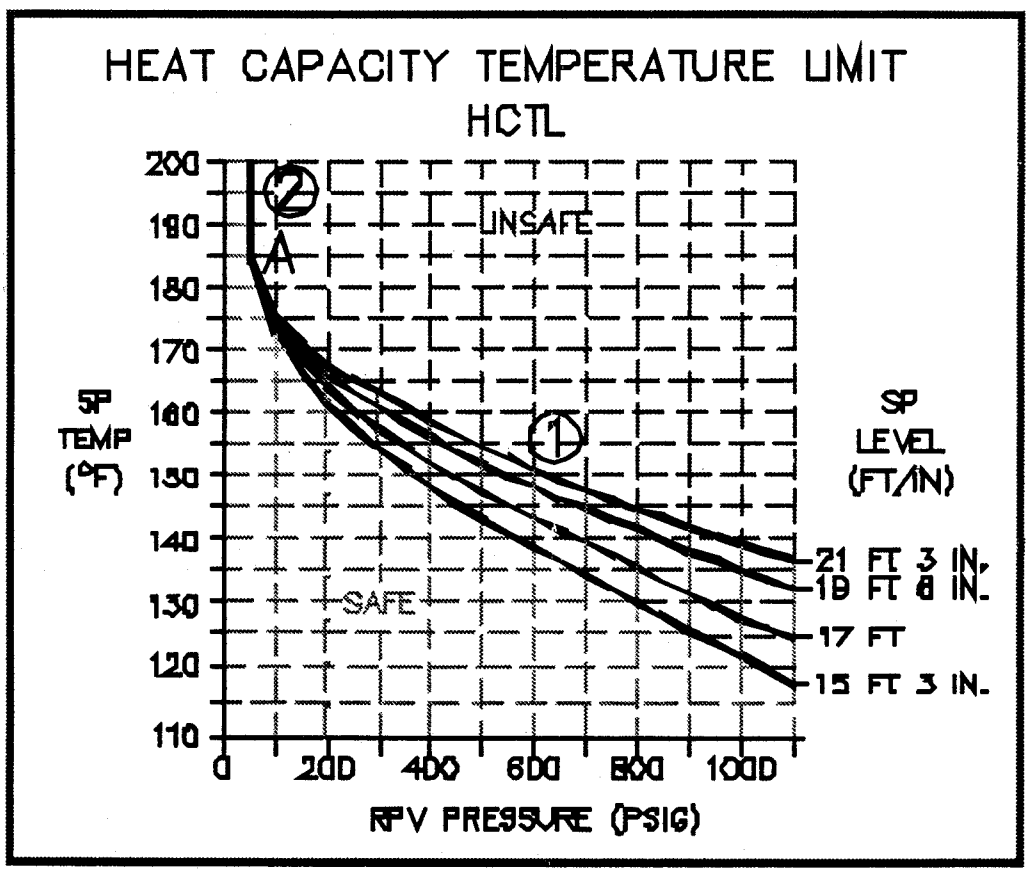
A.3 Heat Capacity Temperature Limit

The Heat Capacity Temperature Limit (HCTL) is the highest suppression pool temperature from which emergency RPV depressurization will not raise:

- Containment temperature above the maximum temperature capability of the containment and equipment within the containment which may be required to operate when the RPV is pressurized, or
- Containment pressure above the Primary Containment Pressure Limit,

while the rate of energy transfer from the RPV to the containment is greater than the capacity of the containment vent.

The HCTL is a function of RPV pressure and suppression pool water level. It is utilized to preclude failure of the containment and equipment in the containment necessary for the safe shutdown of the plant.



HCTL curves are defined for selected suppression pool water levels between the elevation two feet above the top of the Mark III horizontal vents and the Maximum Pressure Suppression Primary Containment Water Level. Each curve comprises two lines: ① and ②. When RPV pressure is at or below the Minimum RPV Flooding Pressure, the rate of energy transfer from the RPV to the containment (with the Minimum Number of SRVs Required for Emergency Depressurization open) is, by definition of the Minimum RPV Flooding Pressure, within the capacity of the containment vent. The HCTL is therefore vertical at the Minimum RPV Flooding Pressure. The intersection of Lines ① and ② (Point A) is defined by this pressure and the lesser of:

- The maximum temperature capability of the containment and equipment within the containment which may be required to operate when the RPV is pressurized, and
- The containment temperature at which containment pressure will be at the Primary Containment Pressure Limit.

For RPV pressures above the Minimum RPV Flooding Pressure, the HCTL ensures that there is sufficient heat capacity in the suppression pool to sustain a blowdown. If a blowdown is initiated from any point on Line ②, RPV pressure will drop below the Minimum RPV Flooding Pressure before suppression pool temperature rises above the ordinate of Point A. Since a blowdown from higher pressures adds more energy to the suppression pool, the HCTL decreases with increasing pressure. The abscissa of the high pressure endpoint is the lowest SRV lift setpoint.

The low-pressure endpoint temperature of the HCTL is limited by the maximum temperature capability of the containment and equipment within the containment, Point A is independent of suppression pool water level and the HCTL curves converge to a single point.

The HCTL is determined by heat balance between the RPV and the suppression pool assuming:

1. The reactor has been shutdown from rated power for two minutes when RPV depressurization is initiated.
2. RPV water level is at the high level trip setpoint when RPV depressurization is initiated.
3. No water is injected into the RPV during the RPV depressurization.
4. RPV depressurization is effected using the Minimum Number of SRVs Required for Emergency Depressurization.
5. An SRV will pass 110% of nameplate flow at 103% of nameplate pressure.
6. All steam from the RPV is rejected to the suppression pool.
7. When RPV depressurization is initiated, suppression pool water level is between:
    - The elevation two feet above the top of the Mark III horizontal vents, and
    - The Maximum Pressure Suppression Primary Containment Water Level.

8. Suppression pool cooling is unavailable.

9. The RPV, internals, and fuel are in thermal equilibrium with the water in the RPV when RPV pressure reaches the Minimum RPV Flooding Pressure.

10. All noncondensibles in the containment are in the containment when RPV pressure reaches the Minimum RPV Flooding Pressure.

11. The containment atmosphere and the suppression pool are in thermal equilibrium when RPV pressure reaches the Minimum RPV Flooding Pressure.

Plant-specific data required to calculate the HCTL are:

1. Primary Containment Pressure Limit.

2. Minimum RPV Flooding Pressure.

3. Minimum Number of SRVs Required for Emergency Depressurization.

4. Maximum Pressure Suppression Primary Containment Water Level.

5. Maximum temperature capability of the containment and equipment within the containment which may be required to operate when the RPV is pressurized.

6. Rated reactor thermal power.

7. Lowest SRV lifting setpoint pressure.

8. SRV nameplate flowrate and pressure.

9. Mass of water in the recirculation and RWCU loops and in the RPV with RPV water level at the high level trip setpoint an RPV water temperature at the saturation temperature for the lowest SRV lifting setpoint pressure.

10. Mass of saturated steam in the RPV and main steam lines inboard of the outboard MSIVs with RPV water level at the high level trip setpoint and RPV pressure at the lowest SRV lifting setpoint.

11. Masses of the RPV, recirculation loops, main steam lines inboard of the outboard MSIVs, RPV internals, fuel, clad, and channels.

12. Volume of water in suppression pool as a function of water level.

13. Free volume of the drywell.

14. Minimum normal operating drywell and containment temperatures.

15. Maximum normal operating drywell and containment pressures.
16. Elevation of the top of the Mark III horizontal vents.
17. Minimum and maximum suppression pool water level LCOs.
18. Elevation of the suppression pool water level instrument zero.
19. Free volume of the containment airspace as a function of suppression pool water level.
20. Suppression pool temperature at which a reactor scram is required by plant Technical Specifications.
21. Specific heat of clad and channels.
22. Specific heat of fuel.

A.24 Pressure Suppression Pressure

The Pressure Suppression Pressure (PSP) is the lesser of:

- The highest containment pressure which can occur without steam in the containment airspace.
- The highest containment pressure at which initiation of RPV depressurization will not result in exceeding the Primary Containment Pressure Limit before RPV pressure drops to the Minimum RPV Flooding Pressure.
- The highest containment pressure which can be maintained without exceeding the suppression pool boundary design load if SRVs are opened.

The PSP is a function of primary containment water level. It is utilized to assure the pressure suppression function of the containment is maintained while either the RPV is at pressure or primary containment flooding is required.

The derivation of the PSP is shown graphically in Figure A-10. Line ① corresponds to the highest containment pressure which can occur without steam in the containment airspace. This pressure is determined by calculating the pressure that would exist as a function of suppression pool water level with all drywell noncondensibles purged to the containment and suppression pool temperature at the Heat Capacity Temperature Limit corresponding to the lowest SRV lift pressure. Higher suppression pool water levels result in higher pressures since the airspace volume is smaller.

Line ② is the suppression pool water level corresponding to the elevation two feet above the horizontal vents. If suppression pool water level is below this elevation, the RPV may not be kept in a pressurized state since steam discharged through the vents may not be condensed. The PSP is therefore vertical at this elevation.

Line ③ is the suppression pool water level corresponding to the Maximum Pressure Suppression Primary Containment Water Level. Above this elevation, the pressure suppression function of the containment cannot be assured. The PSP is therefore vertical at this elevation.

The PSP is determined assuming:

1. The highest containment pressure which can occur without steam in the containment air space is the lowest containment pressure which results when all the noncondensibles in the containment are in the containment and the suppression pool temperature is at the Heat Capacity Temperature Limit temperature which corresponds to the lowest SRV lifting setpoint pressure.
2. The highest containment pressure at which initiation of RPV depressurization will not result in exceeding the Primary Containment Pressure Limit before RPV pressure drops to the Minimum RPV Flooding Pressure is the Primary Containment Pressure Limit less the maximum containment airspace pressure increase which results from depressurizing the RPV from the

lowest SRV lifting setpoint pressure to the Minimum RPV Flooding Pressure, compensating for change in suppression pool heat capacity with change in primary containment water level.

3. The highest containment pressure which can be maintained without exceeding the suppression pool boundary design load if SRVs are opened is the suppression pool boundary design pressure less (1) the maximum suppression pool boundary load which results from any actuation and (2) the hydrostatic head between the primary containment water level and the suppression pool water level which was assumed in determining the maximum suppression pool boundary load which results from SRV actuation.

4. Suppression pool cooling is unavailable.

5. The suppression pool and containment atmosphere are in thermal equilibrium.

Plant-specific data required to calculate the PSP are:

1. Primary Containment Pressure Limit.

2. Heat Capacity Temperature Limit.

3. Maximum Pressure Suppression Primary Containment Water Level.

4. Suppression pool boundary design load.

5. Maximum suppression pool boundary load which results from SRV actuation and the suppression pool water level which was assumed in determining this load.

6. Elevation of the suppression pool water level instrument zero.

7. Elevation of the top of the Mark III horizontal vents.

8. Elevation of the containment pressure instrument tap.

9. Free volume of the containment airspace as a function of suppression pool water level.

10. Free volume of the drywell.

11. Maximum normal operating drywell and containment temperatures.

12. Minimum normal operating drywell and containment pressures.

13. Minimum temperature of the suppression pool when the containment is flooded.

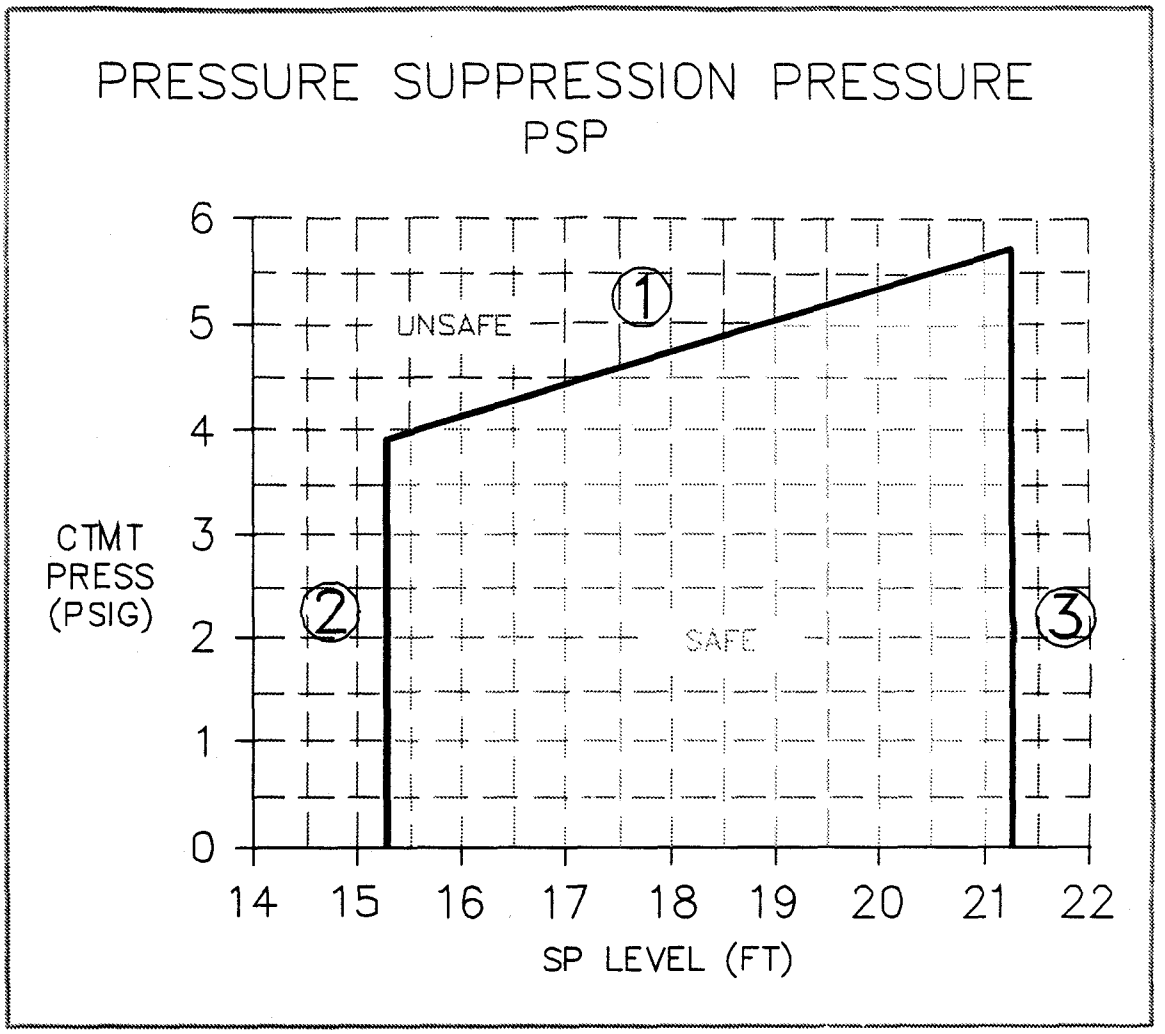


Figure A-10: Pressure Suppression Pressure Derivation

2) QUESTION - RO 19:

The following plant conditions exist:

- A loss of offsite power has occurred with a failure of the Div I and Div II EDG to start and tie to their respective buses.
- SRVs are being used to control reactor pressure at 900 psig.
- RCIC is manually initiated (suction from the CST) and is maintaining reactor water level at approximately +20".

Suppression Pool rises and stabilizes at 20' 1"

WHICH ONE (1) of the following describes effect of the above conditions on the RCIC system and the reason for the alignment?

a. RCIC suction remains on the CST since level in the Suppression Pool is below the suction transfer setpoint.

b. RCIC suction remains on the CST. Although Suppression Pool level is above the suction transfer setpoint, the valves have failed to swap due to a loss of AC power.

c. RCIC suction is from the Suppression Pool. Suppression Pool level is above the suction transfer setpoint and the DC powered valves swapped as designed.

d. RCIC will trip on low suction pressure when the DC powered CST suction valve closed on Suppression Pool level and the AC powered Suppression Pool suction valve fails to open.

ANSWER: A

REFERENCE:

NRC KA:	RO:	SRO:
217000 K6.01	3.4	3.5
217000 K1.01	3.5	3.5

QUESTION - RO 19: (Continued)

RECOMMENDATION:

Accept both answers (a) and (c).

JUSTIFICATION:

License Operator Training Manual (LOTM) 20-6, "Reactor Core Isolation Cooling System" page 5 of 33 and Table 2 (page 24 of 33) indicate that the RCIC SUCTION XFER SUPPRESSION POOL LEVEL HIGH setpoint is 19' 10.9". This supports response (c) as being correct.

Alarm Response Procedure (ARP) P601/21A/C05, "RCIC SUCTION XFER SUP PL LEVEL HIGH" indicates that the high suppression pool level transfer setpoint is 20' 3.5". This supports response (a) as being correct.

Based on this information, the candidate could have selected response (a) or (c).

Reference:

LOTM 20-6, Reactor Core Isolation Cooling System

ARP-P601/21A/C05, RCIC SUCTION XFER SUP PL LEVEL HIGH

COMMENT:

Action has been initiated and completed to correct LOTM 20-6 to reflect the current Suppression Pool High Level Suction Transfer setpoint (TEAR RBS-2000-424).

ALARM NO. 2468	RCIC SUCTION XFER SUP PL LEVEL HIGH	H13-P601/21A/C05

INITIATING DEVICES

1. E51-ESN636A or E, Level Transmitter Suppression Pool

SETPOINTS

1. 90' 3.5"
   20' 3.5" Supp Pool

AUTOMATIC ACTIONS

NOTE

An isolation signal to close E51-F031 overrides the suppression pool high level signal.

1. E51-F031, RCIC PUMP SUP PL SUCTION VALVE opens.
2. E51-F010, RCIC PUMP CST SUCTION VALVE closes.
3. E51-F022, RCIC TEST BYPASS VLV TO CST closes.
4. E51-F059, RCIC TEST RETURN VLV TO CST closes.

OPERATOR ACTIONS

1. Verify Automatic Actions occur.

LONG TERM ACTIONS

1. Investigate and determine cause of suppression pool high level.
2. Upon restoring suppression pool level to normal, return RCIC valve lineup to normal per SOP-0035, Reactor Core Isolation Cooling System.
3. If operating RCIC in the test mode, then secure RCIC per SOP-0035, Reactor Core Isolation Cooling System.

POSSIBLE CAUSES

1. RCIC or HPCS running on minimum flow to Suppression Pool
2. Instrument malfunction

REFERENCES

1. 1.ILICS.009
2. 1.ILICS.010
3. 828E539AA Sh 10

II. SYSTEM DETAILS

A. Detailed Flow Path (Figure 1)

1. Steam Flow

Steam for operation of the RCIC turbine is provided from MSL A inside the drywell upstream of the inboard MSIV (B21-F022A). The steam piping size is 8" up to the RHR system tap and then reduces to 4" for supplying the RCIC turbine.

The steam piping to the turbine is kept hot to allow rapid starting of the turbine, therefore allowing rated RCIC system flow to be attained in less than 30 seconds when needed. This is accomplished by a normal valve lineup and piping and drain trap arrangement which maintains the steam piping at near normal operating temperature.

The turbine is designed for immediate starting with no warmup prior to operation at rated speed. Turbine exhaust steam is directed to the suppression pool for condensation via 12" piping.

A gland seal air compressor system is provided to prevent steam leakage from the turbine glands, governor and throttle valves

2. Water Flow

The RCIC pump suction is normally lined up to the CST. Suction automatically shifts to the suppression pool when:

- a low level exists in the CST (0"), or
- a high level exists in the Suppression Pool (19'10.9") with a RCIC isolation signal not present.

This shift takes place after a 2 second time delay to prevent inadvertent shifts caused by pressure transients which occur when the HPCS pump starts (the HPCS pump and RCIC pump have a common suction with pressure transmitters which sense CST level).

A minimum flow line is provided from the RCIC pump discharge to the suppression pool to protect the pump if a low flow condition exists. This feature protects the RCIC pump during starting and stopping when discharge pressure is less than reactor pressure. When the system senses adequate pump discharge pressure and flow, the minimum flow valve is automatically closed.

Table 2 (continued)

1H13*P601/21A ANNUNCIATORS

TITLE	SETPOINT	AUTOMATIC ACTIONS
RCIC SUCTION XFER SUP PL LEVEL HIGH	89' - 10.9" (19' - 10.9" in SP)	**NOTE:** An isolation signal to close E51-MOVF031 will override the suppression pool high level signal. – RCIC pump suppression pool suction valve (E51-MOVF031) opens. – RCIC pump CST suction valve (E51-MOVF010) closes. – RCIC test bypass valve to CST (E51-MOVF022) closes. – RCIC test return valve to CST (E51-MOVF059) closes.
RCIC ISOL FROM STM TNL HI AMB IMMINENT	0 seconds 141°F	– RCIC turbine trips. – RCIC steam supply outboard isol valve (E51-MOVF064) closes. – RCIC steam supply inboard isol valve (E51-MOVF063) closes. – RCIC pump suppression pool suction valve (E51-MOVF031) closes. – RCIC warmup line shutoff valve (E51-MOVF076) closes. – RCIC inject isol valve (E51-MOVF013) closes.
DIV II RCIC ISOL MN STM SPLY LINE DIFF PRESS HIGH	Various Instruments Hi d/p	RCIC System Auto Isolation: – RCIC turbine trips. – RCIC steam supply valve (E51-MOVF063) closes. – RCIC warmup line shutoff valve (E51-MOVF076) closes. – RCIC inject isol valve (E51-MOVF013) closes. – RCIC min flow valve to suppression pool (E51-MOVF019) closes.

3) QUESTION - RO 80:

Given the following conditions:

- Drywell temperature and pressure are increasing due to a leak
- Drywell pressure is 1.82 psig
- Suppression Pool temperature is 101 degrees Fahrenheit
- All expected automatic actions have occurred
- EOP-2, "Primary Containment Control", was entered for high drywell temperature and high Suppression Pool temperature.
- Enclosure 20 for restoration of drywell cooling is in progress
- RHR "A" and RHR "B" are in suppression pool cooling

Once the interlocks have been defeated, which of the following will be providing cooling to the drywell?

A. Drywell cooler fans and normal service water.

B. Drywell cooler fans and chilled water.

C. Drywell cooler fans and standby service water

D. Drywell cooler fans ONLY.

ANSWER: C

REFERENCE: HLO-038 05, EOP-0002, Encl. 20, SOP-0031

NRC KA:	RO:	SRO:
295012 K2.02	3.6	3.7
295012 K1.01	3.3	3.5

QUESTION - RO 80: (Continued)

RECOMMENDATION:

Accept both answers (a) and (c).

JUSTIFICATION:

The EPSTG (EOP basis document) for EOP-2 step SPT-3 gives the Operator latitude to initially place only partial Suppression Pool Cooling in service so that manpower resources can be applied to more critical areas. The Operators would then monitor Suppression Pool temperature and if needed, place additional cooling in service which may require Standby Service Water to be initiated. The procedure for operation of Suppression Pool Cooling (SOP-0031, Residual Heat Removal) allows operation of both loops (RHR A and RHR B) of Suppression Pool Cooling on Normal Service Water provided that flow through all in service Residual Heat Removal heat exchangers does not exceed 5800 gpm. Based on this information and the fact that no Suppression Pool temperature trend was given, it is conceivable that maximum Suppression Pool cooling may not be immediately placed in service and hence Normal Service Water would be supplying the Drywell Unit Coolers.

Under the given plant conditions, Normal Service Water or Standby Service Water could be supplying the Drywell Unit Coolers which would make both (a) and (c) answers correct.

Reference:

EPSTG*0002 Appendix A
SOP-0031
SOP-0018

EOP-2 Step (SPT-1)

Discussion

The initial action taken to control suppression pool temperature employs the same method typically used during normal plant operations: monitoring its status and placing available suppression pool cooling in operation as required to maintain temperature within Technical Specification limits. Step SPT-1 thus provides a smooth transition from general plant procedures to emergency operating procedures, and assures that the normal method of suppression pool temperature control is attempted in advance of initiating more complex actions to terminate increasing suppression pool temperature.

As used in this step, "available" means that the pumps and support systems necessary to supply suppression pool cooling are capable of performing their identified function and can be placed in service to provide cooling. If a pump cannot be operated due to plant conditions or physical restrictions, it is not considered "available." For example, if an electrical loading concern were to limit operation of the RHR service water pumps, the pumps would not be considered available within the context of this step.

As long as suppression pool temperature remains below the value of the most limiting suppression pool temperature LCO, no further operator action is required in this subsection of the procedure other than continuing to monitor and control suppression pool temperature using available suppression pool cooling systems.

The reference to Caution #5 indicates that, if possible, RHR pumps should be operated within the RHR NPSH and vortex limits when drawing suction from the suppression pool (refer to the discussion of Caution #5 in Section 5 of this appendix). If the situation warrants, however, the limits may be exceeded.

The reference to Caution #8 warns of the effect of low suppression pool water level on suppression pool temperature indications (refer to the discussion of Caution #8 in Section 5 of this appendix).

EOP-2 Step (SPT-2 and 3)

Discussion

When it is determined that suppression pool temperature cannot be maintained below the value of the most limiting suppression pool temperature LCO, a conclusion that may be reached in advance of suppression pool temperature actually reaching this value, the general direction of Step SPT-1 is supplemented with the explicit instruction to place into operation all available methods by which suppression pool cooling can be effected.

The operator may initially place only one RHR loop into service in suppression pool cooling to avoid initiation of the standby service water system and allow the SRO to use his resources in more critical areas. Should one loop of RHR prove inadequate to lower suppression pool temperature, then the operator should place the second loop in service per approved procedures. This meets the intent of "*operate all available suppression pool cooling*". Per Enclosure 1 of OSP-0009, this is consistent with the definition of "*operate*" which is " *to turn on, turn off, start, or stop as necessary to achieve the stated objective*".

Maintaining adequate core cooling takes precedence over maintaining suppression pool temperature below the LCO since catastrophic failure of the primary containment is not expected to occur at this temperature. In addition, further action still remains available for reversing an increasing suppression pool temperature trend (Steps SPT-4, 5, 6, and 7). Therefore, only if continuous operation of a RHR pump in the LPCI mode is not required to assure adequate core cooling is it permissible to use that pump for suppression pool cooling. This step, however, does permit alternating the use of RHR pumps between LPCI injection and suppression pool cooling as the need for each occurs and so long as adequate core cooling is able to be maintained.

If LPCI-C is not required to be operated in order to maintain adequate core cooling SPC/ADHR may be used to provide additional suppression pool cooling.

As used in this step, "*available*" means that the pumps and support systems necessary to supply suppression pool cooling are capable of performing their identified function and can be placed in service to provide cooling. If a pump cannot be operated due to plant conditions or physical restrictions, it is not considered "available." For example, if an electrical loading concern were to limit operation of the RHR service water pumps, the pumps would not be considered available within the context of this step.

C

2.4.12. In Mode 3, during shutdown cooling operations using RHR, RHR Room temperature may reach 122°F with no leak present. Therefore it is possible to exceed the leak detection system setpoint of 117°F. The following precautions will prevent such an isolation.

1. When using Division I RHR, the following components should only be operated as necessary:

   - LPCS Pump
   - RCIC Pump
   - RCIC Gland Seal Compressor

2. When using Div II RHR, use RHR C only as necessary.

3. IF Normal Service Water is being used to cool the rooms, THEN on SWP-TI122, maintain Normal Service Water Temperature is less than 92°F. There are no limits on Standby Service Water Temperature when SSW is operating.

4. Maintain Suppression Pool temperature less than 120°F.

2.5 Miscellaneous

2.5.1. Except as provided in Step 2.5.2, Standby Service Water is to be placed in service prior to exceeding 5800 gpm total service water flow through all in service RHR Heat Exchangers.

a. With Standby Service Water in service, do not exceed 5800 gpm flow through either Division of the RHR Heat Exchangers.

2.5.2. Per ER 98-0273 - 5800 gpm of Normal Service Water may be supplied to each Division of the RHR Hx's during ATWS conditions provided the following guidelines are observed:

- A minimum of 7 NSW Hx's are in service.
- All SWC Cooling Tower fans are available for operation to maintain NSW temperature less than 95° F.
- Areas cooled by HVR-UC9 (RHR B pump / Hx room, RHR C pump room) are monitored for rising temperatures. These temperatures can be monitored on the following instruments: RHS-ES55 (RHR B) and RHS-ES50 (RHR C) on H13-P841 & P842, E31-R608 pt. 7 (RHR B), E31-N610 (RHR B). Pt. 7 on E31-R608 alarms at 110.5° F and E31-N610 alarms at 117° F.

CAUTION

Excessive Service Water flow through the RHR Heat Exchangers can damage the tubes. Do not exceed 5800 gpm Service Water flow through the RHR Heat Exchangers.

NOTE

Standby Service Water is to be placed in service prior to exceeding 5800 gpm total service water flow through all in service RHR Heat Exchangers.

Per ER 98-0273 - 5800 gpm of Normal Service Water may be supplied to each Division of the RHR Hx's during ATWS conditions provided the guidelines outlined in the Precautions and Limitations are observed.

Two Standby Service Water Pumps are required in each loop when operating the Standby Service Water System for heat removal through the RHR Heat Exchangers.

4.6.4. On H13-P870, throttle open E12-F068A(B), RHR HX A(B) SVCE WTR RTN to establish required flow not to exceed 5800 gpm as indicated on E12-R602A(B), RHR HX A(B) SVCE WTR FLOW.

4.6.5. Start the E12-C002A(B), RHR PUMP A(B) and perform the following:

1. Open E12-F024A(B), RHR PUMP A(B) TEST RTN TO SUP PL.
2. Check running pump amps are less than or equal to 91 amps.

4.6.6. WHEN flow exceeds 1100 gpm, THEN verify E12-F064A(B), RHR PUMP A(B) MIN FLOW TO SUP PL closes.

4.6.7. Throttle closed E12-F048A(B), RHR A(B) HX BYPASS VALVE to obtain the desired cooling.

2.6 Normal Service Water can be supplied to both RHR Heat Exchangers to support modes of operation in both loops, provided combined Normal Service Water Flow does not exceed 5800 gpm.

2.7 Per ER 98-0273 - 5800 gpm of Normal Service Water may be supplied to each Division of the RHR Hx's during ATWS conditions provided the following guidelines are observed:

- A minimum of 7 NSW Hx's are in service.
- All SWC Cooling Tower fans are available for operation to maintain NSW temperature less than 95° F.
- Areas cooled by HVR-UC9 (RHR B pump / Hx room, RHR C pump room) are monitored for rising temperatures. These temperatures can be monitored on the following instruments: RHS-ES55 (RHR B) and RHS-ES50 (RHR C) on H13-P841 & P842, E31-R608 pt. 7 (RHR B), E31-N610 (RHR B). Pt. 7 on E31-R608 alarms at 110.5° F and E31-N610 alarms at 117° F.
- If the area temperature approaches 122° F one division of the RHR Hx's shall be secured.

2.8 Caution must be used when one division of safety related components are being supplied by Normal Service Water, while the other division is being supplied by Standby Service Water. Normal Service Water can be lost in as little as 45 seconds, if Normal Service Water and Standby Service Water are cross tied via the following:

- Drywell Unit Coolers
- Division III Diesel Generator
- HVR-UC5
- CCP Heat Exchangers

2.9 SWP-TK3, SWP SURGE TANK must be monitored closely while water is being drawn from the system. IF tank level is lost, THEN the Normal Service Water Pumps trip on low suction pressure.

2.10 The following applies to the SWP-PVY32A(B)(C)(D) valves:

- WHEN required to be failed open to maintain the chiller OPERABLE, THEN the valve is physically gagged open to meet the operability requirements. The HVK chiller is OPERABLE with the valve gagged open, provided the service water temperature is above 55°F.

4) QUESTION - RO 86:

Which one of the following statements describes the basis for automatic reactor scrams associated with a Main Turbine Trip?

A. In the event of a Main Turbine trip, the Main Steam Bypass valves are too small to handle the capacity of reactor steam flow.

B. Scramming the reactor prevents excessive steam pressures from causing a Main Turbine overspeed condition due to leakage of the Main Turbine Stop and Control Valves.

C. The scram anticipates the decrease in Reactor Recirculation Flow that at high power would result in thermal hydraulic instability

D. The scram inserts a large amount of negative reactivity to prevent exceeding thermal limits at the end of core life because of the distance control rods must insert to be effective.

ANSWER: D

REFERENCE: TS 3.3.1.1, TS 3.3.4.1, CFR 41.4, CFR 41.5

NRC KA:	RO:	SRO:
295005AA2.0	3	3.1
212000K1.10	3.2	
295005 AA2.05	3.8	

QUESTION - RO 86: (Continued)

RECOMMENDATION:

Accept answer (a) and not answer (d).

JUSTIFICATION:

The Main Turbine bypass valves are part of the EHC pressure regulating system. RBS has 9.5% bypass valve capability and during a turbine trip at high power the bypass valves would not pass enough steam flow to limit the reactor pressure, neutron flux, and heat flux transients that would occur. In addition, the Main Turbine Bypass System is required to be operable to limit the peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Safety limit MCPR is not exceeded. Therefore the reactor scram will anticipate the pressure, neutron flux and heat flux increases following a turbine trip thereby prevents exceeding RPV pressure and fuel thermal/hydraulic safety limits.

Response (d) is not correct since it is combines the basis for End-of-Cycle Recirc Pump Trip (EOC-RPT) logic with the basis for the Rx scram on a turbine trip. The first part of the statement ("The scram inserts a large amount of negative reactivity to prevent exceeding thermal limits") describes an aspect of the basis for reactor scram on turbine trip. The last statement ("because of the distance control rods must insert to be effective") is part of the basis for EOC-RPT. Combining these two statements renders (d) an inaccurate statement.

References:

Tech. Spec. 3.7.5 Bases (pages B 3.7-25 and B 3.7-26)
Tech. Spec. 3.3.1.1 (9 and 10) Bases (page B 3.3-16 through B 3.3-18)
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B 3.7 PLANT SYSTEMS

B 3.7.5 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is 9.5% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of a two valve chest connected to the main steam lines between the main steam isolation valves and the turbine stop valves. Each of these valves is sequentially operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Pressure Regulator and Control System, as discussed in the USAR, Section 7.7.1.4 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during the design basis feedwater controller failure, maximum demand event, described in the USAR, Section 15.1.2 (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in an MCPR penalty.

The Main Turbine Bypass System satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Safety Limit MCPR is not exceeded.

An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analysis (Ref. 2).

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists < 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable (one or more bypass valves inoperable), the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status within the associated Completion Time, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8.a, b. Scram Discharge Volume Water Level—High (continued)

accidents or transients analyzed in the USAR. However, they are retained to ensure that the RPS remains OPERABLE.

SDV water level is measured by two diverse methods. The level in each of the two SDVs is measured by two float type level switches and two transmitters and trip units for a total of eight level signals. The outputs of these devices are arranged so that there is a signal from a level switch and a transmitter and trip unit to each RPS logic channel. The level measurement instrumentation satisfies the recommendations of Reference 8.

The Allowable Value is chosen low enough to ensure that there is sufficient volume in the SDV to accommodate the water from a full scram.

Four channels of each type of Scram Discharge Volume Water Level—High Function, with two channels of each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

9. Turbine Stop Valve Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the End of Cycle Recirculation Pump Trip (EOC-RPT) System, ensures that the MCPR SL is not exceeded.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Turbine Stop Valve Closure (continued)

Turbine Stop Valve Closure signals are initiated by limit switches at each stop valve. Two independent limit switches are associated with each stop valve. One of the two limit switches provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve Closure channels, each consisting of one limit switch. The logic for Turbine Stop Valve Closure is such that three or more TSVs must be closed to produce a scram.

This Function must be enabled at THERMAL POWER ≥ 40% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER ≥ 40% RTP. Alternately, the bypass channel can be placed in the conservative condition (non-bypass). If placed in the non-bypass condition, this Surveillance Requirement is met and the channel is considered OPERABLE.

The Turbine Stop Valve Closure Allowable Value is selected to be low enough to detect imminent TSV closure thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Stop Valve Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if the TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ 40% RTP. This Function is not required when THERMAL POWER is < 40% RTP since the Reactor Vessel Steam Dome Pressure-High and the Average Power Range Monitor Fixed Neutron Flux-High Functions are adequate to maintain the necessary safety margins.

10. Turbine Control Valve Fast Closure, Trip Oil Pressure-Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

10. Turbine Control Valve Fast Closure, Trip Oil Pressure—Low (continued)

transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System, ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure—Low signals are initiated by the EHC fluid pressure at each control valve. There is one pressure transmitter associated with each control valve, the signal from each transmitter being assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ 40% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER ≥ 40% RTP. Alternately, the bypass channel can be placed in the conservative condition (non-bypass). If placed in the non-bypass condition, this Surveillance Requirement is met and the channel is considered OPERABLE. The basis for the setpoint of this automatic bypass is identical to that described for the Turbine Stop Valve Closure Function.

The Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Four channels of Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is ≥ 40% RTP. This Function is not required when THERMAL POWER is < 40% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

(continued)

TABLE 2

REACTOR SCRAM BASIS

SCRAM	BASIS
Mode Switch in SHUTDOWN	Provided as backup manual scram capability.
Scram Discharge Volume Level High	Scrams the reactor while volume is still sufficient to accommodate the water displaced from control rod insertion.
Reactor Water Level Low (Level 3)	Indicates the reactor is in danger of being undercooled. Set low enough to prevent spurious scrams during operation.
Reactor Water Level High (Level 8)	Intended to offset the positive reactivity effects associated with excessive feedwater addition.
Reactor Steam Dome Pressure High	Prevents excessive pressure which could rupture the primary pressure boundary and result in the release fission products and positive reactivity addition due to void collapse High enough to prevent spurious trips during normal operation.
Drywell Pressure High	Indicates a break in the primary pressure boundary or a loss of Drywell Cooling. Minimize the possibility of fuel damage and reduces the energy released to the Primary Containment.
Turbine Stop Valve Closure	Anticipates the pressure, neutron and thermal flux increases resulting from TSV closure, while maintaining an adequate margin to the SAFETY LIMITS.
Turbine Control Valve Closure	Anticipates the pressure, neutron flux and heat flux increases following a fast closure of the TCV's due to a load rejection with or without a coincident failure of Bypass valve.
MSIV Closure	Anticipates the pressure and flux transients associated with MSIV closure, thereby prevents exceeding RPV pressure and fuel thermal/hydraulic SAFETY LIMITS.
IRM Flux High	Acts as a backup to the APRM's to prevent power excursions which could cause core damage between the source range and the power range.
IRM INOP	Too few detector s to effectively monitor power.

5) QUESTION - RO 95:

WHICH ONE (1) of the following is the consequence of operating the Division I EDG with a loss of control air pressure?

A. All non emergency shutdown functions on the Diesel are inhibited. Emergency shutdown functions remain operable.

B. All shutdown functions on the Diesel are inhibited.

C. The Diesel engine will shutdown.

D. The jacket cooling water temperature control valve will fail open.

ANSWER: C

REFERENCE: SOP-0053

NRC KA:	RO:	SRO:
2.1.28	3.2	3.6

QUESTION - RO 95: (Continued)

RECOMMENDATION:

Accept both answers (b) and (c).

JUSTIFIACTION:

The stem of the question does not state the mode of operation (emergency start vs. normal start) for the Emergency Diesel Generator. The candidate had to assume a mode of operation for the Diesel Generator.

If the candidate assumed an emergency start, then answer (b) is correct. The attached Failure Modes and Effects Analysis (FM&EA) states that in the "emergency mode" of operation the Emergency Diesel Generator will not shutdown on a loss of air to the pneumatic control system.

If the candidate assumed a normal start, then answer (c) is correct. At 40# and lowering control air pressure, the EDG will trip.

Reference:

Failure Modes and Effects Analysis (FM&EA)

Purpose

The purpose of this Failure Modes and Effects Analysis (FM&EA) is to evaluate the standby emergency deisel/generators' pneumatic control system to determine whether or not the diesels will continue to operate upon a decrease in control air pressure leading to a complete loss of all control air pressure. This FM&EA also evaluates the effects of the air pressure being restored after a loss of control air pressure.

System Description

The SDGs function to provide emergency power to essential auxiliaries for safe shutdown in the event of a Loss of Offsite Power (LOP) or LOP coincident with a Loss of Coolant Accident (LOCA). Two SDGs are permanently assigned to two of the three electrical system 4.16 kV busses (Division I and II).

The Engine Control System (ECS) provides the following controls for the SDGs:

1. Starting
2. Stopping
3. Operating the SDGs at synchronous speed with droop capabilities for testing operation in parallel with the grid,
4. Stopping the SDG upon receipt of a trip signal,
5. Bypass non-emergency trips on receipt of an emergency start signal, and
6. Monitoring of key diesel generator parameters.

In the event of a loss of preferred (offsite) power, the Standby Diesel Generator System shall supply power to the Division I and II safety related equipment required for shutting down the reactor safely, maintaining a safe shutdown condition, and operating all auxiliaries required to mitigate the consequences of an accident (Ref.: 7.7.4.1, GDC 17).

The diesel generator auxiliary systems are required to operate to support the operation of the Standby DG System.

During standby, all diesel and generator trips are required to be reset, generator and auxiliary system controls must be in automatic, and fluid levels must be adequate to support diesel operations.

Each standby diesel generator starts on a LOP and/or LOCA, and supplies power to operate the load assigned to its associated engineered safety feature (ESF) 4.16 kV bus, if offsite power is lost to that bus. If offsite power is available, the standby diesel generator is capable of operating with zero electrical load for 7 days. During this mode of operation, the diesel generator auxiliary systems will operate, as described below, to support the operation of the Standby DG System.

An independent Diesel Generator Starting System (DGSS) is provided for each standby diesel generator. A redundant starting system train is provided for each diesel generator to ensure high

Conclusion

Based on the analysis and testing that created this FM&EA, it can be concluded that the diesel generators will not shut down on a loss of air to the pneumatic control system. The shutdown cylinders did not move as pressure was slowly decreased to zero. In the overspeed trip circuit upon slowly decreasing pressure, the system air appeared to follow the path of least resistance, leaking to the atmosphere out of the "13" valve EX port. Further decrease caused more air to pass the EX port. By the time the valves fully shifted, pressure was less than 10 psig, and was insufficient to move the S/D cylinders. Therefore, the pressure at the shutdown cylinders never built up sufficiently to cause the extension of the cylinders.

On rapid restoration of air, 5 seconds or less, both shutdown cylinders extend fully for about 1 second, then retract as the "13" and "28" valves reset. The faster the restoration, the stronger the cylinder extension response. On a slow restoration of air, more than 5 seconds, the valves do not reset, the fuel cylinder extends over 50%, the air cylinder hardly at all. The fuel cylinder extension could act as a load limiter.

Recommendations

It is recommended that the controls for the DIV I & II EGA air compressors be modified such that the compressors will not auto-start if the receiver tank pressure falls below the minimum pilot holding pressure for the "13" and "28" valves. Such a modification would prevent an automatic repressurization of the D/G control system while a D/G is running in emergency mode thereby preventing the condition which causes the shutdown cylinders to inadvertently actuate. This modification is being installed under ER 98-0426.

As an enhancement, it is recommended that a valve configuration be installed in the pneumatic control system to prevent the extension of the shutdown cylinders upon restoration of instrument air pressure following a loss of air pressure. One configuration involves the installation of two globe valves. One of these globe valves would be located in the instrument line between the overspeed trip pressure regulator and the "28" valve. The other would be located between the "28" valve and the next upstream shuttle valve. The installation of these valves would allow for the isolation of the "28" valve until adequate system pressure could build up to prevent the extension and retraction of the shutdown cylinders as the "13" and "28" valves reset. A different valve configuration would involve the installation of one globe valve in the instrument line between the "28" valve and the tee that sends air signals to both shutdown cylinders. This would allow the "28" and "13" valves to reset without sending a signal to extend the shutdown cylinders. Either valve configuration would provide for the repressurization of the system while preventing the extension of the shutdown cylinders. For both configurations, the closure of these valves prior to repressurization the system and the opening of these valves once adequate system pressure is attained would be administratively controlled.

Also as a result if this FM&EA, ER 99-0094 has been generated to rescind Parts Interchangeability Evaluation (PIE) 00858. This PIE provided Humphrey F573132 valves as an acceptable alternative replacement for Humphrey F573160 valves. It was found that the Viton diapragm in the F57160 valves in superior to the Buna-N diaphragm in the F57132 valves. Therefore, PIE 00858 is being cancelled by ER 99-0094.