October 7, 1993

Docket Nos. 50-275
and 50-323

Mr. Gregory M. Rueger
Nuclear Power Generation, B14A
Pacific Gas and Electric Company
77 Beale Street, Room 1451
P.O. Box 770000
San Francisco, California 94177

Dear Mr. Rueger:

SUBJECT: ISSUANCE OF AMENDMENTS FOR DIABLO CANYON NUCLEAR POWER PLANT, UNIT NO. 1 (TAC NO. M84580) AND UNIT NO. 2 (TAC NO. M84581)

The Commission has issued the enclosed Amendment No. 84 to Facility Operating License No. DPR-80 and Amendment No. 83 to Facility Operating License No. DPR-82 for the Diablo Canyon Nuclear Power Plant, Unit Nos. 1 and 2, respectively. The amendments consist of changes to the Technical Specifications (TS) in response to your application dated September 21, 1992, as supplemented February 2, 1993, March 8 and 31, 1993, May 7 and 27, 1993, June 1 and 18, 1993, and August 11 and 27, 1993.

These amendments incorporate both the Eagle 21 reactor protection system upgrade and RTD bypass manifold elimination. The changes include revisions to Definitions, Action Statements, Allowable Values, Bases, Functional Units, Notes, and Response Times. In addition, the licensee added trip time delays (SG low-low water level), revised steam line break logic, and a new steam generator high-high level turbine trip setpoint.

A copy of the related Safety Evaluation is enclosed. A notice of issuance will be included in the Commission's next regular biweekly Federal Register notice.

Sincerely,
Original Signed by
Sheri R. Peterson, Project Manager
Project Directorate V
Division of Reactor Projects III/IV/V
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 84 to DPR-80
2. Amendment No. 83 to DPR-82
3. Safety Evaluation

cc w/enclosures:
See next page

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DATE	10/7/93	10/6/93	09/29/93	10/7/93

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

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Sheri R. Peterson

Sheri R. Peterson, Project Manager
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Office of Nuclear Reactor Regulation

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cc w/enclosures:
See next page

cc:
NRC Resident Inspector
Diablo Canyon Nuclear Power Plant
c/o U.S. Nuclear Regulatory Commission
P. O. Box 369
Avila Beach, California 93424

Dr. Richard Ferguson, Energy Chair
Sierra Club California
6715 Rocky Canyon
Creston, California 93432

Ms. Nancy Culver
San Luis Obispo
Mothers for Peace
P. O. Box 164
Pismo Beach, California 93448

Ms. Jacquelyn C. Wheeler
3303 Barranca Court
San Luis Obispo, California 93401

Managing Editor
The County Telegram Tribune
1321 Johnson Avenue
P. O. Box 112
San Luis Obispo, California 93406

Chairman
San Luis Obispo County Board of
Supervisors
Room 370
County Government Center
San Luis Obispo, California 93408

Mr. Truman Burns
Mr. Robert Kinosian
California Public Utilities Commission
505 Van Ness, Rm. 4102
San Francisco, California 94102

Diablo Canyon Independent Safety Committee
ATTN: Robert R. Wellington, Esq.
Legal Counsel
857 Cass Street, Suite D
Monterey, California 93940

Mr. Steve Hsu
Radiologic Health Branch
State Department of Health Services
Post Office Box 942732
Sacramento, California 94234

Regional Administrator, Region V
U.S. Nuclear Regulatory Commission
1450 Maria Lane, Suite 210
Walnut Creek, California 94596

Mr. Peter H. Kaufman
Deputy Attorney General
State of California
110 West A Street, Suite 700
San Diego, California 92101

Christopher J. Warner, Esq.
Pacific Gas & Electric Company
Post Office Box 7442
San Francisco, California 94120

Mr. John Townsend
Vice President and Plant Manager
Diablo Canyon Power Plant
P. O. Box 56
Avila Beach, California 93424

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

PACIFIC GAS AND ELECTRIC COMPANY

DOCKET NO. 50-275

DIABLO CANYON NUCLEAR POWER PLANT, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 84
License No. DPR-80

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Pacific Gas & Electric Company (the licensee) dated September 21, 1992, as supplemented February 2, 1993, March 8 and 31, 1993, May 7 and 27, 1993, June 1 and 18, 1993, and August 11 and 27, 1993, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-80 is hereby amended to read as follows:

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(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 84 , are hereby incorporated in the license. Pacific Gas & Electric Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

3. This license amendment is effective for Unit 1 after the Eagle 21 reactor protection system upgrade and the resistance temperature detection bypass elimination, to be completed during the 1R6 refueling outage that is currently scheduled to begin in February 1994.

FOR THE NUCLEAR REGULATORY COMMISSION

Theodore R. Quay

Theodore R. Quay, Director
Project Directorate V
Division of Reactor Projects III/IV/V
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical Specifications

Date of Issuance: October 7, 1993

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

PACIFIC GAS AND ELECTRIC COMPANY

DOCKET NO. 50-323

DIABLO CANYON NUCLEAR POWER PLANT, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 83
License No. DPR-82

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Pacific Gas & Electric Company (the licensee) dated September 21, 1992, as supplemented February 2, 1993, March 8 and 31, 1993, May 7 and 27, 1993, June 1 and 18, 1993, and August 11 and 27, 1993, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. DPR-82 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 83 , are hereby incorporated in the license. Pacific Gas & Electric Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan, except where otherwise stated in specific license conditions.

3. This license amendment is effective for Unit 2 after the Eagle 21 reactor protection system upgrade and the resistance temperature detection bypass elimination, to be completed during the 2R6 refueling outage that is currently scheduled to begin in September 1994.

FOR THE NUCLEAR REGULATORY COMMISSION

Theodore R. Quay

Theodore R. Quay, Director
Project Directorate V
Division of Reactor Projects III/IV/V
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: October 7, 1993

ATTACHMENT TO LICENSE AMENDMENTS

AMENDMENT NO. 84 TO FACILITY OPERATING LICENSE NO. DPR-80

AND AMENDMENT NO. 83 TO FACILITY OPERATING LICENSE NO. DPR-82

DOCKET NOS. 50-275 AND 50-323

Revise Appendix A Technical Specifications by removing the pages identified below and inserting the enclosed pages. The revised pages are identified by the captioned amendment number and contain marginal lines indicating the area of change. Overleaf pages are also included, as appropriate.

REMOVE*		INSERT	
i	3/4 3-29	i	3/4 3-29
1-1	3/4 3-30	1-1	3/4 3-30
1-2	3/4 3-31	1-2	3/4 3-31
2-3	3/4 3-32	2-3	3/4 3-32
2-4	3/4 3-33	2-4	3/4 3-33
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2-6	3/4 3-35	2-6	3/4 3-35
2-7	B 3/4 3-1	2-7	B 3/4 3-1
2-8	B 3/4 3-1a	2-8	B 3/4 3-1a
2-9	B 3/4 3-2	2-9	B 3/4 3-2
---		2-10	
B 2-3		B 2-3	
B 2-5		B 2-5	
B 2-6		B 2-6	
B 2-7		B 2-7	
3/4 3-3		3/4 3-3	
3/4 3-6		3/4 3-6	
3/4 3-7		3/4 3-7	
3/4 3-8		3/4 3-8	
3/4 3-10		3/4 3-10	
3/4 3-11		3/4 3-11	
3/4 3-12		3/4 3-12	
3/4 3-13		3/4 3-13	
3/4 3-14		3/4 3-14	
3/4 3-15		3/4 3-15	
3/4 3-18		3/4 3-18	
3/4 3-19		3/4 3-19	
3/4 3-20		3/4 3-20	
3/4 3-21		3/4 3-21	
3/4 3-22		3/4 3-22	
3/4 3-23		3/4 3-23	
3/4 3-24		3/4 3-24	
3/4 3-25		3/4 3-25	
3/4 3-26		3/4 3-26	
3/4 3-27		3/4 3-27	

* - The Appendix A Technical Specifications should not be removed until both units have completed the subject modification.

INDEX

DEFINITIONS

SECTION PAGE

1.0 DEFINITIONS

CHANNEL FUNCTIONAL TEST

1.7 A CHANNEL FUNCTIONAL TEST shall be:

a. Analog channels - the injection of a simulated signal into the channel as close to the sensor as practicable to verify OPERABILITY including alarm and/or trip functions, or

b. Bistable channels - the injection of a simulated signal into the sensor to verify OPERABILITY including alarm and/or trip functions.

c. Digital channels - the injection of a simulated signal into the channel as close to the sensor input to the process racks as practical to verify OPERABILITY including alarm and/or trip functions.

CONTAINMENT INTEGRITY

1.8 CONTAINMENT INTEGRITY shall exist when:

a. All penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE containment automatic isolation valve system, or

2. Closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed positions, except for valves that are open under administrative control as permitted by Specification 3.6.3.

b. All equipment hatches are closed and sealed,

c. Each air lock is in compliance with the requirements of Specification 3.6.1.3,

d. The containment leakage rates are within the limits of Specification 3.6.1.2, and

e. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

CONTROLLED LEAKAGE

1.9 CONTROLLED LEAKAGE shall be that seal water flow supplied to the reactor coolant pump seals.

CORE ALTERATIONS

1.10 CORE ALTERATIONS shall be the movement or manipulation of any fuel, sources, or reactivity control components within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe conservative position.

1.0 DEFINITIONS

The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications.

ACTION

1.1 ACTION shall be that part of a Specification which prescribes remedial measures required under designated conditions.

ACTUATION LOGIC TEST

1.2 An ACTUATION LOGIC TEST shall be the application of various simulated input combinations in conjunction with each possible interlock logic state and verification of the required logic output. The ACTUATION LOGIC TEST shall include a continuity check, as a minimum, of output devices.

CHANNEL OPERATIONAL TEST

1.3 A CHANNEL OPERATIONAL TEST shall be the injection of a simulated signal into the channel as close to the sensor as practicable to verify OPERABILITY of alarm, interlock and/or trip functions. The CHANNEL OPERATIONAL TEST shall include adjustments, as necessary, of the alarm, interlock and/or trip setpoints such that the setpoints are within the required range and accuracy.

AXIAL FLUX DIFFERENCE

1.4 AXIAL FLUX DIFFERENCE shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.

CHANNEL CALIBRATION

1.5 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel such that it responds within the required range and accuracy to known values of input. The CHANNEL CALIBRATION shall encompass the entire channel including the sensors and alarm, interlock and/or trip functions and may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

CHANNEL CHECK

1.6 A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 The Reactor Trip System Instrumentation and Interlock Setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2-1.

APPLICABILITY: As shown for each channel in Table 3.3-1.

ACTION:

a. With a Reactor Trip System Instrumentation or Interlock Setpoint less conservative than the value shown in the Trip Setpoint column but more conservative than the value shown in the Allowable Value column of Table 2.2-1, adjust the Setpoint consistent with the Trip Setpoint value.

b. With a Reactor Trip System Instrumentation or Interlock Setpoint less conservative than the value shown in the Allowable Values column of Table 2.2-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its Setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	N.A.	N.A
2. Power Range, Neutron Flux		
a. Low Setpoint	≤ 25% of RATED THERMAL POWER	≤ 27.1% of RATED THERMAL POWER
b. High Setpoint	≤ 109% of RATED THERMAL POWER	≤ 111.1% of RATED THERMAL POWER
3. Power Range, Neutron Flux High Positive Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 6.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds
4. Power Range, Neutron Flux High Negative Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 6.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds
5. Intermediate Range, Neutron Flux	≤ 25% of RATED THERMAL POWER	≤ 30.9% of RATED THERMAL POWER
6. Source Range, Neutron Flux	≤ 10^5 counts per second	≤ 1.4 x 10^5 counts per second
7. Overtemperature ΔT	See Note 1	See Note 2
8. Overpower ΔT	See Note 3	See Note 4
9. Pressurizer Pressure-Low	≥ 1950 psig	≥ 1944.4 psig
10. Pressurizer Pressure-High	≤ 2385 psig	≤ 2390.6 psig
11. Pressurizer Water Level-High	≤ 92% of instrument span	≤ 92.5% of instrument span
12. Reactor Coolant Flow-Low	≥ 90% of minimum measured flow** per loop	≥ 89.7% of minimum measured flow** per loop

**Minimum measured flow is 89,800 gpm per loop for Unit 1 and 90,625 gpm per loop for Unit 2.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
13. Steam Generator Water Level-Low-Low	≥ 7.2% of narrow range instrument span-each steam generator	≥ 6.8% of narrow range instrument span-each steam generator
Coincident with:		
a. RCS Loop ΔT Equivalent to Power ≤ 50% RTP	RCS Loop ΔT variable input ≤ 50% RTP	RCS Loop ΔT variable input ≤ 51.5% RTP
With a time delay (TD)	≤ TD (Note 5)	≤ (1.01)TD (Note 5)
Or		
b. RCS Loop ΔT Equivalent to Power > 50% RTP		
With no time delay		
14. DELETED		
15. Undervoltage-Reactor Coolant Pumps	≥ 8050 volts-each bus	≥ 7730 volts-each bus
16. Underfrequency-Reactor Coolant Pumps	≥ 54.0 Hz - each bus	≥ 53.9 Hz - each bus
17. Turbine Trip		
a. Low Autostop Oil Pressure	≥ 50 psig	≥ 45 psig
b. Turbine Stop Valve Closure	≥ 1% open	≥ 1% open
18. Safety Injection Input from ESF	N.A.	N.A.
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.
20. Reactor Trip Breakers	N.A.	N.A.
21. Automatic Trip and Interlock Logic	N.A.	N.A.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
22. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 1 \times 10^{-10}$ amps	$\geq 6 \times 10^{-11}$ amps
b. Low Power Reactor Trips Block, P-7		
1) P-10 Input	10% of RATED THERMAL POWER	≥ 7.9%, ≤ 12.1% of RATED THERMAL POWER
2) P-13 Input	≤ 10% RTP Turbine Impulse Pressure Equivalent	≤ 12.1% RTP Turbine Impulse Pressure Equivalent
c. Power Range Neutron Flux, P-8	≤ 35% of RATED THERMAL POWER	≤ 37.1% of RATED THERMAL POWER
d. Power Range Neutron Flux, P-9	≤ 50% of RATED THERMAL POWER	≤ 52.1% of RATED THERMAL POWER
e. Power Range Neutron Flux, P-10	10% of RATED THERMAL POWER	≥ 7.9%, ≤ 12.1% of RATED THERMAL POWER
f. Turbine Impulse Chamber Pressure, P-13	≤ 10% RTP Turbine Impulse Pressure Equivalent	≤ 12.1% RTP Turbine Impulse Pressure Equivalent
23. Seismic Trip	≤ 0.35 g	≤ 0.40 g

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 1: OVERTEMPERATURE ΔT

$$\Delta T \left(\frac{1 + \tau_4 S}{1 + \tau_5 S}\right) \leq \Delta T_o \left| K_1 - K_2 \left(\frac{1 + \tau_1 S}{1 + \tau_2 S}\right) [T - T'] + K_3(P - P') - f_1(\Delta I) \right|$$

Where: $\frac{1 + \tau_4 S}{1 + \tau_5 S}$ = Lead-lag compensator on measured ΔT

τ_4, τ_5 = Time constants utilized in the lead-lag controller for ΔT, τ_4 = 0 seconds, τ_5 = 0 seconds

ΔT_o = Indicated ΔT at RATED THERMAL POWER

K_1 = 1.2

K_2 = 0.0182/°F

$\frac{1 + \tau_1 S}{1 + \tau_2 S}$ = The function generated by the lead-lag controller for T_{avg} dynamic compensation

τ_1, τ_2 = Time constants utilized in the lead-lag controller for T_{avg}, τ_1 = 30 seconds, τ_2 = 4 seconds

T = Average temperature, °F

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 1: (continued)

T'	= Nominal T_{avg} at RATED THERMAL POWER
K_3	= 0.000831/psig
P	= Pressurizer pressure, psig
P'	= 2235 psig (Nominal RCS operating pressure)
S	= Laplace transform operator, s^{-1}

and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between -19% and +9%, $f_1(\Delta I) = 0$ (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER).

(ii) for each percent that the magnitude of $(q_t - q_b)$ exceeds -19%, the ΔT Trip Setpoint shall be automatically reduced by 2.75% of its value at RATED THERMAL POWER.

(iii) for each percent that the magnitude of $(q_t - q_b)$ exceeds +9%, the ΔT Trip Setpoint shall be automatically reduced by 1.76% of its value at RATED THERMAL POWER.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 1.0% ΔT span.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 3: Overpower ΔT

$$\Delta T \left(\frac{1 + \tau_4 S}{1 + \tau_5 S}\right) \leq \Delta T_o \left\{ K_4 - K_5 \left(\frac{\tau_3 S}{1 + \tau_3 S}\right) T - K_6 \left[T - T''\right] - f_2(\Delta I) \right\}$$

Where: $\frac{1 + \tau_4 S}{1 + \tau_5 S}$ = Lead-lag compensator on measured ΔT

τ_4, τ_5 = Time constants utilized in the lead-lag controller for ΔT, τ_4 = 0 seconds, τ_5 = 0 seconds

ΔT_o = Indicated ΔT at RATED THERMAL POWER

K_4 = 1.072

K_5 = 0.0174/°F for increasing average temperature, and 0 for decreasing average temperature

$\frac{\tau_3 S}{1 + \tau_3 S}$ = The function generated by the rate-lag controller for T_{avg} dynamic compensation

τ_3 = Time constants utilized in the rate-lag controller for T_{avg}, τ_3 = 10 secs.

K_6 = 0.0014/°F for $T > T''$, and 0 for $T \leq T''$

T = Average temperature, °F

T" = Indicated T_{avg} at RATED THERMAL POWER

S = Laplace transform operator, s^{-1}

$f_2(\Delta I)$ = 0 for all ΔI

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

NOTE 4: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 1.0% ΔT span

NOTE 5: Steam Generator Water Level Low-Low Trip Time Delay

$$TD = [B1(P)^3 + B2(P)^2 + B3(P) + B4][0.99]$$

Where: P = RCS Loop ΔT Equivalent to Power (%RTP), $P \leq 50\%$ RTP

TD = Time delay for Steam Generator Water Level Low-Low Reactor Trip (in seconds).

B1 = -0.0072

B2 = +0.8181

B3 = -31.72

B4 = +468.8

2.2 LIMITING SAFETY SYSTEM SETTINGS

BASES

2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Trip Setpoint Limits specified in Table 2.2-1 are the nominal values at which the Reactor trips are set for each functional unit. The Trip Setpoints have been selected to ensure that the reactor core and Reactor Coolant System are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist the Engineered Safety Features Actuation System in mitigating the consequences of accidents. The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the Reactor Trip System reaches a preset or calculated level. In addition to redundant channels and trains, the design approach provides a Reactor Trip System which monitors numerous system variables, therefore, providing protection system functional diversity. The setpoint for a reactor trip system or interlock function is considered to be adjusted consistent with the nominal value when the "as left" setpoint is within the band allowed for calibration accuracy. There is a band allowed for calibration accuracy only for those setpoints which use analog hardware. For example, the Power Range, Neutron Flux High setpoint is properly adjusted when it is set at 109% ± 0.3% (0.25% of 120% power span). The setpoints which use digital hardware are set at the nominal value in the system.

The Reactor Trip System initiates a Turbine trip signal whenever Reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive Reactor Coolant System cooldown and thus avoids unnecessary actuation of the Engineered Safety Features Actuation System.

To accommodate the instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, Allowable Values for the Reactor Trip Setpoints have been specified in Table 2.2-1. Operation with a trip set less conservative than its Trip Setpoint, but within its specified Allowable Value, is acceptable.

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensors and other instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

Manual Reactor Trip

The Reactor Trip System includes manual Reactor trip capability.

Power Range, Neutron Flux

In each of the Power Range Neutron Flux channels there are two independent bistables, each with its own trip setting used for a High and Low Range trip setting. The Low Setpoint trip provides protection during subcritical and low power operations to mitigate the consequences of a power excursion beginning from low power, and the High Setpoint trip provides protection during power operations to mitigate the consequences of a reactivity excursion from all power levels.

Power Range, Neutron Flux (Continued)

The Low Setpoint trip may be manually blocked above P-10 (a power level of approximately 10% of RATED THERMAL POWER) and is automatically reinstated below the P-10 setpoint.

Power Range, Neutron Flux, High Rates

The Power Range Positive Rate trip provides protection against rapid flux increases which are characteristic of a rupture of a control rod drive housing. Specifically, this trip complements the Power Range Neutron Flux High and Low trips to ensure that the criteria are met for rod ejection from mid-power.

The Power Range Negative Rate Trip provides protection for control rod drop accidents. At high power, a rod drop accident could cause local flux peaking which could cause an unconservative local DNBR to exist. The Power Range Negative Rate Trip will prevent this from occurring by tripping the reactor. No credit is taken for operation of the Power Range Negative Rate Trip for those control rod drop accidents for which the DNBRs will be greater than or equal to the DNBR limits.

Intermediate and Source Range, Neutron Flux

The Intermediate and Source Range Neutron Flux trips provide core protection durihg reactor STARTUP to mitigate the consequences of an uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition. These trips provide redundant protection to the Low Setpoint trip of the Power Range Neutron Flux channels. The Source Range channels will initiate a Reactor trip at about 10^{+5} counts per second unless manually blocked when P-6 becomes active. The Intermediate Range channels will initiate a Reactor trip at a current level equivalent to approximately 25% of RATED THERMAL POWER unless manually blocked when P-10 becomes active. No credit was taken for operation of the trips associated with either the Intermediate or Source Range channels in the accident analyses; however, their functional capability at the specified trip settings is required by this specification to enhance the overall reliability of the Reactor Trip System.

Overpower ΔT

The Overpower ΔT trip provides assurance of fuel integrity, e.g., no fuel pellet cracking or melting, under all possible overpower conditions, limits the required range for Overtemperature ΔT protection, and provides a backup to the High Neutron Flux trip. The Setpoint is automatically varied

Overpower ΔT (Continued)

with: (1) coolant temperature to correct for temperature induced changes in density and heat capacity of water, and (2) rate of change at temperature for dynamic compensation for delays associated with fluid transport from the core to the loop temperature detectors (RTDs), and thermowell and RTD response time delays. The Overpower ΔT trip provides protection to mitigate the consequences of various size steam breaks as reported in WCAP-9226, "Reactor Core Response to Excessive Secondary Steam Releases."

Delta-T_0, as used in the Overtemperature and Overpower ΔT trips, represents the 100% RTP value as measured by the plant for each loop. This normalizes each loop's ΔT trips to the actual operating conditions existing at the time of measurement, thus forcing the trip to reflect the equivalent full power conditions as assumed in the accident analyses. These differences in RCS loop ΔT can be due to several factors, e.g., measured RCS loop flows greater than minimum measured flow, and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT values. Accurate determination of the loop specific ΔT value should be made when performing Incore/Excore quarterly recalibration and under steady state conditions (i.e., power distributions not affected by xenon or other transient conditions).

Pressurizer Pressure

In each of the pressure channels, there are two independent bistables, each with its own trip setting to provide for a High and Low Pressure trip thus limiting the pressure range in which reactor operation is permitted. The Low Setpoint trip protects against low pressure which could lead to DNB by tripping the reactor in the event of a loss of reactor coolant pressure.

On decreasing power, the Low Setpoint trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with turbine impulse chamber pressure at approximately 10% of full power equivalent); and on increasing power, automatically reinstated by P-7.

The High Setpoint trip functions in conjunction with the pressurizer relief and safety valves to protect the Reactor Coolant System against system overpressure.

Pressurizer Water Level

The Pressurizer High Water Level trip is provided to prevent water relief through the pressurizer safety valves. On decreasing power, the Pressurizer High Water Level trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine impulse chamber pressure at approximately 10% of full power equivalent); and on increasing power, automatically reinstated by P-7.

Reactor Coolant Flow

The Low Reactor Coolant Flow trips provide core protection to prevent DNB by mitigating the consequences of a loss of flow resulting from the loss of one or more reactor coolant pumps.

On increasing power above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a turbine impulse chamber pressure at approximately 10% of full power equivalent), an automatic Reactor trip will occur if the flow in more than one loop drops below 90% of nominal full loop flow. Above P-8 (a power level of approximately 35% of RATED THERMAL POWER) an automatic Reactor trip will occur if the flow in any single loop drops below 90% of nominal full loop flow. Conversely on decreasing power between P-8 and P-7 an automatic reactor trip will occur on loss of flow in more than one loop and below P-7 the trip function is automatically blocked.

Overtemperature ΔT

The Overtemperature ΔT trip provides core protection to prevent DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided (1) that the transient is slow with respect to delays associated with fluid transport from the core to the loop temperature detectors (RTDs), and thermowell and RTD response time delays, and (2) pressure is within the range between the Pressurizer High and Low Pressure trips. The Setpoint is automatically varied with: (1) coolant temperature to correct for temperature induced changes in density and heat capacity of water and includes dynamic compensation for piping delays from the core to the loop temperature detectors, (2) pressurizer pressure, and (3) axial power distribution. With normal axial power distribution, this Reactor trip limit is always below the core Safety Limit as shown in Figure 2.1-1. If axial peaks are greater than design, as indicated by the difference between top and bottom power range nuclear detectors, the Reactor trip is automatically reduced according to the notations in Table 2.2-1.

Delta-T_0, as used in the Overtemperature and Overpower ΔT trips, represents the 100% RTP value as measured by the plant for each loop. This normalizes each loop's ΔT trips to the actual operating conditions existing at the time of measurement, thus forcing the trip to reflect the equivalent full power conditions as assumed in the accident analyses. These differences in RCS loop ΔT can be due to several factors, e.g., measured RCS loop flows greater than minimum measured flow, and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT values. Accurate determination of the loop specific ΔT value should be made when performing Incore/Excore quarterly recalibration and under steady state conditions (i.e., power distributions not affected by xenon or other transient conditions).

Steam Generator Water Level

The Steam Generator Water Level Low-Low trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch resulting from loss of normal feedwater or a feedwater system pipe break, inside or outside of containment. This function also provides input to the steam generator level control system. IEEE 279 requirements are satisfied by 2/3 logic for protection function actuation, thus allowing for a single failure of a channel and still performing the protection function. Control/protection interaction is addressed by the use of the Median Signal Selector which prevents a single failure of a channel providing input to the control system requiring protection function action. That is, a single failure of a channel providing input to the control system does not result in the control system initiating a condition requiring protection function action. The Median Signal Selector performs this by not selecting the channels indicating the highest or lowest steam generator levels as input to the control system.

The Trip Time Delay (TTD) creates additional operational margin when the plant needs it most, during early escalation to power, by allowing the operator time to recover level when the primary side load is sufficiently small to allow such action. The TTD is based on continuous monitoring of primary side power through the use of RCS loop ΔT. The magnitude of the delays decreases with increasing primary side power level, up to 50% RTP. Above 50% RTP there are no time delays for the Low-Low Level trips.

In the event of failure of a Steam Generator Water Level channel, the channel is placed in the trip condition as input to the Solid State Protection System and does not affect the TTD setpoint calculations for the remaining OPERABLE channels. Failure of the RCS loop ΔT channel input to the TTD does not affect the TTD calculation for a protection set. This results in the requirement that the operator adjust the threshold power level for zero seconds time delay from 50% RTP to 0% RTP, through the Man Machine Interface.

Undervoltage and Underfrequency - Reactor Coolant Pump Busses

The Undervoltage and Underfrequency Reactor Coolant Pump Bus trips provide core protection against DNB as a result of complete loss of forced coolant flow. The specified Setpoints assure a Reactor trip signal is generated before the Low Flow Trip Setpoint is reached. Time delays are incorporated in the Underfrequency and Undervoltage trips to prevent spurious Reactor trips from momentary electrical power transients. For undervoltage, the delay is set so that the time required for a signal to reach the Reactor trip breakers following the simultaneous trip of two or more reactor coolant pump bus circuit breakers shall not exceed 0.9 seconds. For underfrequency, the delay is set so that the time required for a signal to reach the Reactor trip breakers after the Underfrequency Trip Setpoint is reached shall not exceed 0.3 seconds. On decreasing power, the Undervoltage and Underfrequency Reactor Coolant Pump Bus trips are automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine impulse chamber pressure at approximately 10% of full power equivalent); and on increasing power, reinstated automatically by P-7.

Turbine Trip

A Turbine trip initiates a Reactor trip. On decreasing power, the Turbine trip is automatically blocked by P-9 (a power level of approximately 50% of RATED THERMAL POWER); and on increasing power, reinstated automatically by P-9.

Safety Injection Input from ESF

If a Reactor trip has not already been generated by the Reactor Trip System instrumentation, the ESF automatic actuation logic channels will initiate a Reactor trip upon any signal which initiates a Safety Injection. The ESF instrumentation channels which initiate a Safety Injection signal are shown in Table 3.3-3.

Reactor Coolant Pump Breaker Position Trip

The Reactor Coolant Pump Breaker Position trip is an anticipatory trip which provides score protection against DNB. The Open/Close Position trip assures a reactor trip signal is generated before the Low Flow Trip Setpoint is reached. No credit was taken in the safety analyses for operation of this trip. The functional capability at the open/close position settings is required to enhance the overall reliability of the Reactor Trip System. Above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a turbine impulse chamber pressure at approximately 10% of full power equivalent) an automatic reactor trip will occcur if more than one reactor coolant pump breaker is opened. Below P-7 the trip function is automatically blocked.

Reactor Trip System Interlocks

The Reactor Trip System Interlocks perform the following functions:

P-6 On increasing power, P-6 allows the manual block of the Source Range trip and de-energizing of the high voltage to the detectors. On decreasing power, Source Range Level trips are automatically reactivated and high voltage restored.

P-7 On increasing power, P-7 automatically enables Reactor trips on low flow in more than one reactor coolant loop, more than one reactor coolant pump breaker open, reactor coolant pump bus undervoltage and underfrequency, pressurizer low pressure and pressurizer high level. On decreasing power, the above listed trips are automatically blocked.

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
12. Reactor Coolant Flow-Low					
a. Single Loop (Above P-8)	3/loop	2/loop in one loop	2/loop in each loop	1	6
b. Two Loops (Above P-7 and below P-8)	3/loop	2/loop in two loops	2/loop in each loop	1	6
13. Steam Generator Water Level Low-Low					
a. Steam Generator Water Level-Low-Low	3/S.G.	2/S.G. in one S.G.	2/S.G. in each S.G.	1, 2	6
b. RCS Loop ΔT	4 (1/loop)	2	3	1, 2	27
14. DELETED					
15. Undervoltage-Reactor Coolant Pumps	2/bus	1/bus both busses	1/bus	1	28
16. Underfrequency-Reactor Coolant Pumps	3/bus	2 on same bus	2/bus	1	28
17. Turbine Trip					
a. Low Autostop Oil Pressure	3	2	2	1	7
b. Turbine Stop Valve Closure	4	4	4	1	7

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Safety Injection Input from ESF	2	1	2	1, 2	26
19. Reactor Coolant Pump Breaker Position Trip above P-7	1/breaker	2	1/breaker	1	9
20. Reactor Trip Breakers	2	1	2	1, 2	10, 12
	2	1	2	3*, 4*, 5*	11
21. Automatic Trip and Interlock Logic	2	1	2	1, 2	26
	2	1	2	3*, 4*, 5*	11
22. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
b. Low Power Reactor Trips Block, P-7 P-10 Input	4	2	3	1	8#
P-13 Input	2	1	2	1	8#
c. Power Range Neutron Flux, P-8	4	2	3	1	8#
d. Power Range Neutron Flux, P-9	4	2	3	1	8#
e. Power Range Neutron Flux, P-10	4	2	3	1, 2	8#
f. Turbine Impulse Chamber Pressure, P-13 (Input to P-7)	2	1	2	1	8#
23. Seismic Trip	3 directions (x,y,z) in 3 locations	2/3 locations one direction	2/3 locations all directions	1, 2	13

TABLE 3.3-1 (Continued)

TABLE NOTATIONS

*When the Reactor Trip System breakers are in the closed position and the Control Rod Drive System is capable of rod withdrawal.

#The provisions of Specification 3.0.4 are not applicable.

##Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

###Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

ACTION STATEMENTS

ACTION 1 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours,

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1, and

c. Either, THERMAL POWER is restricted to less than or equal to 75% of RATED THERMAL POWER and the Power Range Neutron Flux Trip Setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored per Specification 4.2.4.2 when THERMAL POWER is greater than or equal to 50% of RATED THERMAL POWER.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 3 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint, and

b. Above the P-6 Setpoint, but below 10% of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 10% of RATED THERMAL POWER.

ACTION 4 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement suspend all operations involving positive reactivity changes.

ACTION 5 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement, verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, within 1 hour and at least once per 12 hours thereafter.

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel or one additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1.

ACTION 7 - With the number of OPERABLE channels less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the inoperable channel(s) is (are) placed in the tripped condition within 6 hours.

ACTION 8 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

ACTION STATEMENTS (Continued)

ACTION 9 - With less than the Minimum Number of Channels OPERABLE, operation may continue provided the inoperable channel is placed in the tripped condition within the next 6 hours.

ACTION 10 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

ACTION 11 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor trip breakers within the next hour.

ACTION 12 - With one of the diverse trip features (Undervoltage or shunt trip attachment) inoperable, restore it to OPERABLE status within 48 hours or declare the breaker inoperable and apply ACTION 10. The breaker shall not be bypassed while one of the diverse trip features is inoperable except for the time required for performing maintenance to restore the breaker to OPERABLE status.

ACTION 13 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The Minimum Channels OPERABLE requirement is met, and

b. The inoperable channel is placed in the tripped conditions within 6 hours; however, the inoperable channel may be bypassed for up to 72 hours for surveillance testing per Specification 4.3.1.1 or for performing maintenance.

ACTION 26 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable Channel to OPERABLE status within 6 hours or be in at least HOT STANDBY within the next 6 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

ACTION 27 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided that within 6 hours, for the affected protection set, the Trip Time Delay threshold power level for zero seconds time delay is adjusted to 0% RTP.

ACTION 28 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the trip condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.

TABLE 3.3-2

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT			RESPONSE TIME
1.	Manual Reactor Trip		N.A.
2.	Power Range, Neutron Flux		≤ 0.5 second[(1)]
3.	Power Range, Neutron Flux, High Positive Rate		N.A.
4.	Power Range, Neutron Flux, High Negative Rate		≤ 0.5 second[(1)]
5.	Intermediate Range, Neutron Flux		N.A.
6.	Source Range, Neutron Flux		≤ 0.5 second[(1)]
7.	Overtemperature ΔT		≤ 7 seconds[(1)]
8.	Overpower ΔT		≤ 7 seconds[(1)]
9.	Pressurizer Pressure-Low		≤ 2 seconds
10.	Pressurizer Pressure-High		≤ 2 seconds
11.	Pressurizer Water Level-High		N.A.
12.	Reactor Coolant Flow-Low		
	a.	Single Loop (Above P-8)	≤ 1 second
	b.	Two Loops (Above P-7 and below P-8)	≤ 1 second
13.	Steam Generator Water Level-Low-Low		
	a.	Steam Generator Water Level-Low-Low	≤ 2 seconds[(2)]
	b.	RCS Loop ΔT Equivalent Power	N.A.
14.	DELETED		
15.	Undervoltage-Reactor Coolant Pumps		≤ 1.2 seconds
16.	Underfrequency-Reactor Coolant Pumps		≤ 0.6 second

(1) Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

(2) Does not include Trip Time Delays. Response times include the transmitters, Eagle-21 Process Protection cabinets, Solid State Protection System cabinets and actuation devices only. This reflects the response times necessary for THERMAL POWER in excess of 50% RTP.

TABLE 3.3-2 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
17. Turbine Trip	
a. Low Fluid Oil Pressure	N.A.
b. Turbine Stop Valve	N.A.
18. Safety Injection Input from ESF	N.A.
19. Reactor Coolant Pump Breaker Position Trip	N.A.
20. Reactor Trip Breakers	N.A.
21. Automatic Trip and Interlock Logic	N.A.
22 Reactor Trip System Interlocks	N.A.
23. Seismic Trip	N.A.

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R(14)	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux						
a. High Setpoint	S	D(2, 4), M(3, 4), Q(4, 6), R(4, 5)	Q	N.A.	N.A.	1, 2
b. Low Setpoint	S	R(4)	S/U(1)	N.A.	N.A.	1###, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(4)	Q	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R(4)	Q	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	S	R(4, 5)	S/U(1)	N.A.	N.A.	1###, 2
6. Source Range, Neutron Flux	S	R(4, 5)	S/U(1),Q(8)	N.A.	N.A.	2##, 3, 4, 5
7. Overtemperature ΔT	S	R	Q	N.A.	N.A.	1, 2
8. Overpower ΔT	S	R	Q	N.A.	N.A.	1, 2
9. Pressurizer Pressure-Low	S	R	Q	N.A.	N.A.	1
10. Pressurizer Pressure-High	S	R	Q	N.A.	N.A.	1, 2
11. Pressurizer Water Level-High	S	R	Q	N.A.	N.A.	1
12. Reactor Coolant Flow-Low	S	R	Q	N.A.	N.A.	1

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
13. Steam Generator Water Level-Low-Low						
a. Steam Generator Water Level-Low-Low	S	R	Q	N.A.	N.A.	1, 2
b. RCS Loop ΔT	N.A.	R	Q	N.A.	N.A.	1, 2
14. DELETED						
15. Undervoltage-Reactor Coolant Pumps	N.A.	R	N.A.	Q	N.A.	1
16. Underfrequency-Reactor Coolant Pumps	N.A.	R	N.A.	Q	N.A.	1
17. Turbine Trip						
a. Low Fluid Oil Pressure	N.A.	N.A.	N.A.	S/U(1, 9)	N.A.	1
b. Turbine Stop Valve Closure	N.A.	N.A.	N.A.	S/U(1, 9)	N.A.	1
18. Safety Injection Input from ESF	N.A.	N.A.	N.A.	R	N.A	1, 2
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	N.A.	R	N.A.	1
20. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	N.A.	R(4)	R	N.A.	N.A.	2##
b. Low Power Reactor Trips Block, P-7	N.A.	R(4)	R	N.A.	N.A.	1
c. Power Range Neutron Flux, P-8	N.A.	R(4)	R	N.A.	N.A.	1

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
20. Reactor Trip System Interlocks (Continued)						
d. Power Range Neutron Flux, P-9	N.A.	R(4)	R	N.A.	N.A.	1
e. Low Setpoint Power Range Neutron Flux, P-10	N.A.	R(4)	R	N.A.	N.A.	1, 2
f. Turbine Impulse Chamber Pressure, P-13	N.A.	R	R	N.A.	N.A.	1
21. Reactor Trip Breaker	N.A.	N.A.	N.A.	M(7, 10)	N.A.	1,2,3*,4*,5*
22. Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A.	M(7)	1,2,3*,4*,5*
23. Seismic Trip	N.A.	R	N.A.	R	R	1, 2
24. Reactor Trip Bypass Breaker	N.A	N.A.	N.A.	M(7.15),R(16)	N.A.	1,2,3*,4*,5*

TABLE 4.3-1 (Continued)

TABLE NOTATIONS

* - When the Reactor Trip System breakers are closed and the Control Rod Drive System is capable of rod withdrawal.

\## - Below P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

\### - Below P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

(1) - If not performed in previous 31 days.

(2) - Heat balance only, above 15% of RATED THERMAL POWER. During startup in MODE 1 above 15% of RATED THERMAL POWER, the required heat balance shall be performed prior to exceeding 30% of RATED THERMAL POWER, or within 24 hours, whichever occurs first. Adjust channel if absolute difference greater than 2%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(3) - Compare incore to excore axial flux difference above 15% of RATED THERMAL POWER at least once per 31 Effective Full Power days. Recalibrate if the absolute difference is greater than or equal to 3%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(4) - Neutron detectors may be excluded from CHANNEL CALIBRATION.

(5) - Detector plateau curves shall be obtained and evaluated for the source range neutron flux channels. For the Intermediate Range and Power Range Neutron Flux channels a test shall be performed that shows allowed variances of detector voltage do not effect detector operation. For the Intermediate Range and Power Range Neutron Flux Channels the provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(6) - Incore - Excore Calibration, above 75% of RATED THERMAL POWER at least once per 92 Effective Full Power days. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(7) - Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(8) - Quarterly Surveillance in MODES 3*, 4* and 5* shall also include verification that permissives P-6 and P-10 are in their required state for existing plant conditions by observation of the permissive annunciator window.

(9) - Setpoint verification is not applicable.

(10) - The TRIP ACTUATING DEVICE OPERATIONAL TEST shall separately verify the OPERABILITY of the undervoltage and shunt trip attachments of the Reactor Trip Breakers.

(11) - DELETED

(12) - Deleted

(13) - Deleted

3/4.3.2 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The Engineered Safety Features Actuation System (ESFAS) instrumentation channels and interlocks shown in Table 3.3-3 shall be OPERABLE with their Trip Setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4 and with RESPONSE TIMES as shown in Table 3.3-5.

APPLICABILITY: As shown in Table 3.3-3.

ACTION:

a. With an ESFAS Instrumentation Channel or Interlock Trip Setpoint less conservative than the value shown in the Trip Setpoint column but more conservative than the value shown in the Allowable Value column of Table 3.3-4, adjust the Setpoint consistent with the Trip Setpoint value.

b. With an ESFAS Instrumentation or Interlock Trip Setpoint less conservative than the value shown in the Allowable Value column of Table 3.3-4, declare the channel inoperable and apply the applicable ACTION statement requirements of Table 3.3-3 until the channel is restored to OPERABLE status with its Trip Setpoint adjusted consistent with the Trip Setpoint value.

SURVEILLANCE REQUIREMENTS

4.3.2.1 Each ESFAS instrumentation channel and interlock and the automatic actuation logic and relays shall be demonstrated OPERABLE by the performance of the Engineered Safety Feature Actuation System Instrumentation Surveillance Requirements specified in Table 4.3-2.

4.3.2.2 The ENGINEERED SAFETY FEATURES RESPONSE TIME of each ESFAS function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one train such that both trains are tested at least once per 36 months and one channel per function such that all channels are tested at least once per N times 18 months where N is the total number of redundant channels in a specific ESFAS function as shown in the "Total No. of Channels" column of Table 3.3-3.

TABLE 3.3-3

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Safety Injection (Reactor Trip, Feedwater Isolation, Start Diesel Generators, Containment Fan Cooler Units, and Component Cooling Water)					
a. Manual Initiation	2	1	2	1, 2, 3, 4	19
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
c. Containment Pressure-High	3	2	2	1, 2, 3, 4	20
d. Pressurizer Pressure-Low	4	2	3	1, 2, 3#	20
e. DELETED					
f. Steam Line Pressure-Low	3/steam line	2/steam line in any steam line	2/steam line	1, 2, 3#	20

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
2. Containment Spray					
a. Manual	2	2 with 2 coincident switches	2	1, 2, 3, 4	19
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
c. Containment Pressure-High-High	4	2	3	1, 2, 3	17
3. Containment Isolation					
a. Phase "A" Isolation					
1) Manual	2	1	2	1, 2, 3, 4	19
2) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
3) Safety Injection	See Item 1. above for all Safety Injection initiating functions and requirements.				
b. Phase "B" Isolation					
1) Manual	2	2 with 2 coincident switches	2	1, 2, 3, 4	19

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
3. Containment Isolation (Continued)					
2) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
3) Containment Pressure-High-High	4	2	3	1, 2, 3	17
c. Containment Ventilation Isolation					
1) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	18
2) Plant Vent Noble Gas Activity-High[(a)] (RM-14A and 14B)	2	1	2	1, 2, 3, 4	18
3) Safety Injection	See Item 1. above for all Safety Injection initiating functions and requirements.				
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)[(b)]	2	1	2	1, 2, 3, 4	18
4. Steam Line Isolation					
a. Manual	1 manual switch/steam line	1 manual switch/steam line	1 manual switch/operating steam line	1, 2, 3, 4	24

(a)The requirements for Plant Vent Noble Gas Activity-High (RM-14A and 14B) are not applicable following installation of RM-44A and 44B.

(b)The requirements for Containment Ventilation Exhaust Radiation-High (RM-44A and 44B) are applicable following installation of RM-44A and 44B.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. Steam Line Isolation (Continued)					
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	22
c. Containment Pressure-High-High	4	2	3	1, 2, 3	17
d. Steam Line Pressure-Low	3/steam line	2/steam line in any steam line	2/steam line	1, 2, 3#	20
e. Negative Steam Line Pressure Rate-High	3/steam line	2/steam line in any steam line	2/steam line	3##	20
5. Turbine Trip & Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2	25
b. Steam Generator Water Level-High-High	3/stm. gen.	2/stm. gen. in any operating stm. gen.	2/stm. gen. in each operating stm. gen.	1, 2	20

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
6. Auxiliary Feedwater					
a. Manual Initiation	1 manual switch/pump	1 manual switch/pump	1 manual switch/pump	1, 2, 3	24
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	22
c. Stm. Gen. Water Level-Low-Low					
1) Start Motor-Driven Pumps					
a. Steam Generator Water Level-Low-Low	3/S.G.	2/S.G. in one S.G.	2/S.G. in each S.G.	1, 2, 3	20
b. RCS loop ΔT	4 (1/loop)	2	3	1, 2, 3	29
2) Start Turbine-Driven Pump					
a. Steam Generator Water Level-Low-Low	3/S.G.	2/S.G. in one S.G.	2/S.G. in each S.G.	1, 2, 3	20
b. RCS loop ΔT	4 (1/loop)	2	3	1, 2, 3	29
d. Undervoltage-RCP Bus Start Turbine-Driven Pump	2/bus	1/bus on both busses	1/bus	1	35
e. Safety Injection Start Motor-Driven Pumps	See Item 1. above for all Safety Injection initiating functions and requirements.				

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
7. Loss of Power (4.16 kV Emergency Bus Undervoltage)					
a. First Level				1, 2, 3, 4	
1) Diesel Start	1/Bus	1/Bus	1/Bus		16
2) Initiation of Load Shed	2/Bus	2/Bus	2/Bus		16
b. Second Level				1, 2, 3, 4	
1) Undervoltage Relays	2/Bus	2/Bus	2/Bus		16
2) Timers to Start Diesel	1/Bus	1/Bus	1/Bus		16
3) Timers to Shed Load	1/Bus	1/Bus	1/Bus		16
8. Engineered Safety Features Actuation System Interlocks					
a. Pressurizer Pressure, P-11	3	2	2	1, 2, 3	21
b. DELETED					
c. Reactor Trip, P-4	2	2	2	1, 2, 3	23

TABLE 3.3-3 (Continued)

TABLE NOTATIONS

#Trip function may be blocked in this MODE below the P-11 (Pressurizer Pressure Interlock) Setpoint.

##Trip function automatically blocked above P-11 (Pressurizer Pressure Interlock) Setpoint and may be manually blocked below P-11 when Safety Injection on Steam Line Pressure-Low is not blocked.

ACTION STATEMENTS

ACTION 14 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 6 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1, provided the other channel is OPERABLE.

ACTION 15 - Deleted

ACTION 16 - With the number of OPERABLE Channels one less than the Total Number of Channels, declare the affected Emergency Diesel Generator(s) inoperable and comply with the ACTION statements of Specification 3.8.1.1; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.2.1.

ACTION 17 - With the number of OPERABLE channels one less than the Total Number of Channels, operation may proceed provided the inoperable channel is placed in the bypassed condition and the Minimum Channels OPERABLE requirement is met. One additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.

ACTION 18 - With less than the Minimum Channels OPERABLE requirement, operation may continue provided the containment purge supply and exhaust valves (RCV-11, 12, FCV 660, 661, 662, 663, 664) are maintained closed.

TABLE 3.3-3 (Continued)

ACTION STATEMENTS (Continued)

ACTION 19 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION 20 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel or one additional channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1.

ACTION 21 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

ACTION 22 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 6 hours or be in at least HOT STANDBY within the next 6 hours and in at least HOT SHUTDOWN within the following 6 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1 provided the other channel is OPERABLE.

ACTION 23 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

ACTION 24 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or declare the associated pump or valve inoperable and take the ACTION required by Specification 3.7.1.5 or 3.7.1.2 as applicable.

ACTION 25 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 6 hours or be in at least HOT STANDBY within the next 6 hours; however, one channel may be bypassed for up to 4 hours for surveillance testing per Specification 4.3.2.1 provided the other channel is OPERABLE.

ACTION 29 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided that within 6 hours, for the affected protection set, the Trip Time Delay threshold power level for zero seconds time is adjusted to 0% RTP.

ACTION 35 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the trip condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.2.1.

TABLE 3.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT		TRIP SETPOINT	ALLOWABLE VALUES
1.	Safety Injection (Reactor Trip, Feedwater Isolation, Start Diesel Generators, Containment Fan Cooler Units, and Component Cooling Water)		
	a. Manual Initiation	N.A.	N.A
	b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A
	c. Containment Pressure-High	≤ 3 psig	≤ 3.3 psig
	d. Pressurizer Pressure-Low	≥ 1850 psig	≥ 1844.4 psig
	e. DELETED		
	f. Steam Line Pressure-Low	≥ 600 psig (Note 1)	≥ 594.6 psig (Note 1)

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. Containment Spray		
a. Manual Initiation	N.A.	N.A
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A
c. Containment Pressure-High-High	≤ 22 psig	≤ 22.3 psig
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual	N.A.	N.A
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	
b. Phase "B" Isolation		
1) Manual	N.A.	N.A
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A
3) Containment Pressure-High-High	≤ 22 psig	≤ 22.3 psig

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
3. Containment Isolation (Continued)		
c. Containment Ventilation Isolation		
1) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
2) Plant Vent Noble Gas Activity-High (RM-14A and 14B)[(a)]	Per the ODCP	
3) Safety injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)[(b)]	Per Specification 3.3.3.10	
4. Steam Line Isolation		
a. Manual	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 22 psig	≤ 22.3 psig
d. Steam Line Pressure-Low	≥ 600 psig (Note 1)	≥ 594.6 psig (Note 1)

(a) The requirements for Plant Vent Noble Gas Activity-High (RM-14A and 14B) are not applicable following installation of RM-44A and 44B.

(b) The requirements for Containment Ventilation Exhaust Radiation-High (RM-44A and 44B) are applicable following installation of RM-44A and 44B.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
e. Negative Steam Pressure Rate-High	≤-100 psi/sec	≤-105.4 psi/sec
5. Turbine Trip and Feedwater Isolation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Steam Generator Water level-High-High	≤ 75% of narrow range instrument span each steam generator.	≤ 75.5% of narrow range instrument span each steam generator.
6. Auxiliary Feedwater		
a. Manual	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Steam Generator Water Level-Low-Low	≥ 7.2% of narrow range instrument span each steam generator.	≥ 6.8% of narrow range instrument span each steam generator.
Coincident with:		
1) RCS loop ΔT Equivalent to Power ≤ 50% RTP	RCS loop ΔT variable input ≤ 50% RTP	RCS loop ΔT variable input ≤ 51.5% RTP
With a time delay (TD)	TD (Note 2)	≤ (1.01)TD (Note 2)
Or		
2) RCS loop ΔT Equivalent to Power > 50% RTP		
With no time delay		
d. Undervoltage - RCP	≥ 8050 volts	≥ 7730 volts
e. Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.	

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
7. Loss of Power (4.16 kV Emergency Bus Undervoltage)		
a. First Level		
1) Diesel Start	≥ 0 volts with a ≤ 0.8 second time delay and ≥ 2583 volts with a ≤ 10 second time delay	≥ 0 volts with a ≤ 0.8 second time delay and > 2583 volts with a ≤ 10 second time delay
2) Initiation of Load Shed	One relay ≥ 0 volts with a ≤ 4 second time delay and ≥ 2583 volts with a ≤ 25 second time delay with one relay ≥ 2870 volts, instantaneous	One relay ≥ 0 volts with a ≤ 4 second time delay and > 2583 volts with a ≤ 25 second time delay with one relay ≥ 2870 volts, instantaneous
b. Second Level		
1) Diesel Start	≥ 3600 volts with a ≤ 10 second time delay	≥ 3600 volts with a ≤ 10 second time delay
2) Initiation of Load Shed	≥ 3600 volts with a ≤ 20 second time delay	≥ 3600 volts with a ≤ 20 second time delay
8. Engineered Safety Features Actuation System Interlocks		
a. Pressurizer Pressure, P-11	≤ 1915 psig	≤ 1920.6 psig
b. DELETED		
c. Reactor Trip, P-4	N.A.	N.A.

NOTE 1: Time constants utilized in the lead-lag controller for Steam Pressure - Low are τ_1 = 50 seconds and τ_2 = 5 seconds.

NOTE 2: Steam Generator Water Level Low-Low Trip Time Delay

TD = $[B1(P)^3 + B2(P)^2 + B3(P) + B4][0.99]$

Where: P = RCS loop ΔT Equivalent to Power (%RTP), P ≤ 50% RTP

TD = Time Delay for Steam Generator Water Level Low-Low Reactor Trip (in seconds)

Generators affected

B1 = -0.0072
B2 = +0.8181
B3 = -31.72
B4 = +468.8

TABLE 3.3-5

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
1) Feedwater Isolation	N.A.
2) Reactor Trip	N.A.
3) Phase "A" Isolation	N.A.
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater	N.A.
6) Component Cooling Water	N.A.
7) Containment Fan Cooler Units	N.A.
8) Auxiliary Saltwater Pumps	N.A.
b. Phase "B" Isolation	
1) Containment Spray (Coincident with SI Signal)	N.A.
2) Containment Ventilation Isolation	N.A.
c. Phase "A" Isolation	
1) Containment Ventilation Isolation	N.A.
d. Steam Line Isolation	N.A.
2. Containment Pressure-High	
a. Safety Injection (ECCS)	≤ 27[7]/25[4]
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 63
3) Phase "A" Isolation	≤ 18[1]/28[3]
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater	≤ 60[3]
6) Component Cooling Water	≤ 38[1]/48[3]
7) Containment Fan Cooler Units	≤ 40[3]
8) Auxiliary Saltwater Pumps	≤ 48[1]/58[3]
3. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	≤ 27[7]/25[4]/35[5]
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 63
3) Phase "A" Isolation	≤ 18[1]
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater	≤ 60[3]
6) Component Cooling Water	≤ 48[3]/38[1]
7) Containment Fan Cooler Units	≤ 40[3]
8) Auxiliary Saltwater Pumps	≤ 58[3]/48[1]

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
4. Negative Steam Line Pressure Rate-High	
a. Steam Line Isolation	≤ 8
5. DELETED	
6. Steam Line Pressure-Low	
a. Safety Injection (ECCS)	≤ 25(4)/35(5)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 63
3) Phase "A" Isolation	≤ 18(1)/28(3)
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater	≤ 60(3)
6) Component Cooling Water	≤ 38(1)/48(3)
7) Containment Fan Cooler Units	≤ 40(3)
8) Auxiliary Saltwater Pumps	≤ 48(1)/58(3)
b. Steam Line Isolation	≤ 8

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
7. Containment Pressure-High-High	
a. Containment Spray	≤ 48.5(6)
b. Phase "B" Isolation	N.A.
c. Steam Line Isolation	≤ 7
8. Steam Generator Water Level-High-High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	≤ 66
9. Steam Generator Water Level Low-Low	
a. Motor-Driven Auxiliary Feedwater Pumps	≤ 60(3)(8)
b. Turbine-Driven Auxiliary Feedwater Pump	≤ 60(8)
10. RCP Bus Undervoltage	
Turbine-Driven Auxiliary Feedwater Pump	≤ 60
11. Plant Vent Noble Gas Activity-High(a)	
Containment Ventilation Isolation	≤ 11
12. Containment Ventilation Exhaust Radiation-High(b)	
Containment Ventilation Isolation	≤ 11

(a)The requirements for Plant Vent Noble Gas Activity-High are not applicable following installation of RM-44A and 44B.

(b)The requirements for Containment Ventilation Exhaust Radiation-High are applicable following installation of RM-44A and 44B.

TABLE 3.3-5 (Continued)

TABLE NOTATIONS

(1) Diesel generator starting delay not included because offsite power available.

(2) Notation deleted.

(3) Diesel generator starting and loading delays included.

(4) Diesel generator starting delay not included because offsite power is available. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps (where applicable). Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is included.

(5) Diesel generator starting and sequence loading delays included. Offsite power is not available. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is included.

(6) The maximum response time of 48.5 seconds is the time from when the containment pressure exceeds the High-High Setpoint until the spray pump is started and the discharge valve travels to the fully open position assuming off-site power is not available. The time of 48.5 seconds includes the 28-second maximum delay related to ESF loading sequence. Spray riser piping fill time is not included. The 80-second maximum spray delay time does not include the time from LOCA start to "P" signal.

(7) Diesel generator starting and sequence loading delays included. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valves close) is not included. Response time limit includes opening of valves to establish SI flow path and attainment of discharge pressure for centrifugal charging pumps, SI, and RHR pumps (where applicable).

(8) Does not include Trip Time Delays. Response times include the transmitters, Eagle-21 Process Protection cabinets, Solid State Protection System cabinets and actuation devices only. This reflects the response times necessary for THERMAL POWER in excess of 50% RTP.

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Safety Injection, (Reactor Trip Feedwater Isolation, Start Diesel Generators, Containment Fan Cooler Units, and Component Cooling Water)								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q(3)	1, 2, 3, 4
c. Containment Pressure-High	S	R	Q	N.A.	N.A	N.A.	N.A.	1, 2, 3, 4
d. Pressurizer Pressure-Low	S	R	Q	N.A	N.A.	N.A.	N.A.	1, 2, 3
e. DELETED								
f. Steam Line Pressure-Low	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
2. Containment Spray								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3, 4
c. Containment Pressure-High-High	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
3. Containment Isolation								
a. Phase "A" Isolation								
1) Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q(3)	1, 2, 3, 4
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
b. Phase "B" Isolation								
1) Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3, 4
3) Containment Pressure-High-High	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
c. Containment Ventilation Isolation								
1) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3, 4
2) Plant Vent Noble Gas Activity-High (RM-14A and 14B)[(a)]	S	R	M(2)	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)[(b)]	S	R	M(2)	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4

(a) The requirements for Plant Vent Noble Gas Activity-High (RM-14A and 14B) are not applicable following installation of RM-44A and 44B.

(b) The requirements for Containment Ventilation Exhaust Radiation-High (RM-44A and 44B) are applicable following installation of RM-44A and 44B.

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALI-BRATION	CHANNEL OPERA-TIONAL TEST	TRIP ACTUATING DEVICE OPERA-TIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
4. Steam Line Isolation								
a. Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3
c. Containment Pressure-High-High	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
d. Steam Line Pressure-Low	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
e. Negative Steam Line Pressure Rate-High	S	R	Q	N.A.	N.A.	N.A.	N.A.	3(3)
5. Turbine Trip and Feedwater Isolation								
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2
b. Steam Generator Water Level-High-High	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2
6. Auxiliary Feedwater								
a. Manual	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3
c. Steam Generator Water Level-Low-Low								
1) Steam Generator Water Level-Low-Low	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
2) RCS Loop ΔT	N.A.	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
6. Auxiliary Feedwater (Continued)								
d. Undervoltage - RCP	N.A.	R	N.A.	R	N.A.	N.A.	N.A.	1
e. Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
7. Loss of Power								
a. 4.16 kV Emergency Bus Level 1	N.A.	R	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. 4.16 kV Emergency Bus Level 2	N.A.	R	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
8. Engineered Safety Feature Actuation System Interlocks								
a. Pressurizer Pressure, P-11	N.A.	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3
b. Deleted								
c. Reactor Trip, P-4	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3

TABLE NOTATIONS

(1) Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.
(2) For the Plant Vent Activity-High monitor only, a CHANNEL FUNCTIONAL TEST shall be performed at least once every 31 days.
(3) Trip function automatically blocked above P-11 (Pressurizer Pressure Interlock) setpoint and is automatically blocked below P-11 when Safety Injection on Steam Line Pressure-Low is not blocked.

3/4.3.3 MONITORING INSTRUMENTATION

RADIATION MONITORING FOR PLANT OPERATIONS

LIMITING CONDITION FOR OPERATION

3.3.3.1 The radiation monitoring instrumentation channels for plant operations shown in Table 3.3-6 shall be OPERABLE with their Alarm/Trip Setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3-6.

ACTION:

a. With a radiation monitoring channel Alarm/Trip Setpoint for plant operations exceeding the value shown in Table 3.3-6, adjust the Setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels for plant operations inoperable, take the ACTION shown in Table 3.3-6.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each radiation monitoring instrumentation channel for plant operations shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST for the MODES and at the frequencies shown in Table 4.3-3.

BASES

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

The OPERABILITY of the Reactor Trip System and Engineered Safety Features Actuation System instrumentation and interlocks ensure that: (1) the associated ACTION and/or Reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its Setpoint, (2) the specified coincidence logic and sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance consistent with maintaining an appropriate level of reliability of the Reactor Protection and Engineered Safety Features instrumentation, and (3) sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance, and (4) sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundancy, and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the accident analyses. The Surveillance Requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and supplements to that report. Surveillance intervals and out-of-service times were determined based on maintaining an appropriate level of reliability of the Reactor Protection System.

The Process Protection System is designed to permit any one channel to be tested and maintained at power in a bypassed mode. If a channel has been bypassed for any purpose, the bypass is continuously indicated in the control room as required by applicable codes and standards. As an alternative to testing in the bypass mode, testing in the trip mode is also possible and permitted.

The Engineered Safety Features Actuation System senses selected plant parameters and determines whether or not predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents, events, and transients. Once the required logic combination is completed, the system sends actuation signals to those engineered safety features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the Engineered Safety Features Actuation System to mitigate the consequences of a steam line break or loss of coolant accident: (1) safety injection pumps start and automatic valves position, (2) Reactor trip, (3) feedwater isolation, (4) startup of the emergency diesel generators, (5) containment spray pumps start and automatic valves position, (6) containment isolation, (7) steam line isolation, (8) Turbine trip, (9) auxiliary feedwater pumps start and automatic valve position, (10) containment fan cooler units start, and (11) component cooling water pumps start and automatic valves position.

The Engineered Safety Feature Actuation System Instrumentation Trip Setpoints specified in Table 3.3-4 are the nominal values at which the trips are set for each functional unit. If the functional unit is based on analog hardware, the setpoint is considered to be adjusted consistent with the nominal value when the "as left" setpoint is within the band allowed for calibration accuracy. For all setpoints in digital hardware, the setpoints are set at the nominal values.

REACTOR PROTECTION SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

To accommodate the instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, Allowable Values for the setpoints have been specified in Table 3.3-4. Operation with setpoints less conservative than the Trip Setpoint, but within the Allowable Value, is acceptable.

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channel. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensor and rack instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

ESF response times specified in Table 3.3-5, which include sequential operation of the RWST and VCT valves (Table Notations 4 and 5), are based on values assumed in the non-LOCA safety analyses. These analyses take credit for injection of borated water from the RWST. Injection of borated water is assumed not to occur until the VCT charging pump suction isolation valves are closed following opening of the RWST charging pump suction isolation valves. When the sequential operation of the RWST and VCT valves is not included in the response times (Table Notation 7), the values specified are based on the LOCA analyses. The LOCA analyses takes credit for injection flow regardless of the source. Verification of the response times specified in Table 3.3-5 will assure that the assumptions used for the LOCA and non-LOCA analyses with respect to the operation of the VCT and RWST valves are valid.

REACTOR PROTECTION SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

The Engineered Safety Features Actuation System interlocks perform the following functions:

P-4 Reactor tripped - Actuates Turbine trip, closes main feedwater valves on T_{avg} below Setpoint, prevents the opening of the main feedwater valves which were closed by a Safety Injection or High Steam Generator Water Level signal, allows Safety Injection block so that components can be reset or tripped.

Reactor not tripped - prevents manual block of Safety Injection.

P-11 On increasing pressurizer pressure, P-11 automatically reinstates Safety Injection actuation on low pressurizer pressure and low steam line pressure and blocks steam line isolation on steam line pressure negative rate - high. If Safety Injection on low steam line pressure is manually enabled, P-11 will automatically block steam line isolation on steam line pressure negative rate - high. On decreasing pressurizer pressure, P-11 permits the manual block of safety injection on low pressurizer pressure and low steam line pressure and automatically enables steam line isolation on steam line pressure negative rate - high.

3/4.3.3 MONITORING INSTRUMENTATION

3/4.3.3.1 RADIATION MONITORING FOR PLANT OPERATIONS

The OPERABILITY of the radiation monitoring channels ensures that: (1) the radiation levels are continually measured in the areas served by the individual channels and (2) the alarm or automatic action is initiated when the radiation level trip setpoint is exceeded.

3/4.3.3.2 MOVABLE INCORE DETECTORS

The OPERABILITY of the movable incore detectors with the specified minimum complement of equipment ensures that the measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the core. The OPERABILITY of this system is demonstrated by irradiating each detector used and determining the acceptability of its voltage curve.

For the purpose of measuring $F_Q(Z)$ or $F^N_{\Delta H}$ a full incore flux map is used. Quarter-core flux maps, as defined in WCAP-8648, June 1976, may be used in recalibration of the Excore Neutron Flux Detection System, and full incore flux maps or symmetric incore thimbles may be used for monitoring the QUADRANT POWER TILT RATIO when one Power Range channel is inoperable.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

SAFETY EVALUATION REPORT BY THE OFFICE OF NUCLEAR REACTOR REGULATION RELATED TO AMENDMENT NO. 84 TO FACILITY OPERATING LICENSE NO. DPR-80 AND AMENDMENT NO. 83 TO FACILITY OPERATING LICENSE NO. DPR-82

EAGLE 21 REACTOR PROTECTION SYSTEM MODIFICATION WITH BYPASS MANIFOLD ELIMINATION

PACIFIC GAS AND ELECTRIC COMPANY

DIABLO CANYON POWER PLANT, UNITS 1 AND 2

DOCKET 50-275 AND 50-323

1.0 INTRODUCTION

By letter dated September 21, 1992, and subsequent letters dated February 2, 1993, March 8 and 31, 1993, May 7 and 27, 1993, June 1 and 18, 1993, and August 11 and 27, 1993, Pacific Gas and Electric Company, the licensee, submitted a proposal to amend the Facility Operating License Nos. DPR-80 and DPR-82 for Diablo Canyon Units 1 and 2. The proposed amendment revises Technical Specification (TS) Sections 2.2.1, 3/4.3.1, 3/4.3.2 and the applicable bases to incorporate the replacement of the existing Westinghouse 7100 process protection system with Eagle 21 digital process protection equipment.

Additional upgrades included in the proposed Eagle 21 modification are a trip time delay designed to reduce unneeded steam generator water level low-low reactor trips below 50 percent power, new steam line break logic for reduction of spurious safety injection at low power, and an increased steam generator water level high-high turbine trip setpoint. The licensee also included removal of the RTD bypass manifold system (including new thermowell-mounted RTDs) as part of the Eagle 21 upgrade at Diablo Canyon, Units 1 and 2. In addition, the licensee intends to replace the existing vital instrument power inverters with others having increased capacity to support the additional power load demands of the Eagle 21 reactor protection system (RPS).

The supplemental letters dated February 2, 1993, March 8 and 31, 1993, May 7 and 27, 1993, June 1 and 18, 1993, and August 11 and 27, 1993, provided clarifying information and did not affect the initial Federal Register notice and proposed no significant hazards consideration.

2.0 BACKGROUND ON EAGLE 21 UPGRADE

Although the Eagle 21 modification for Diablo Canyon is very similar to others previously approved by the staff, the Diablo Canyon system includes some

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differences in software. Further, plant specific environmental qualification and defense-in-depth issues were considered in the proposed modification. The information submitted by the licensee in support of this proposed amendment addressed the issues identified previously by the staff in the Zion Nuclear Station Eagle 21 Safety Evaluation Report (SER) upgrade and other SERs involving analog/digital upgrades. The licensee also addressed software and hardware issues unique to the Diablo Canyon, Units 1 and 2 Eagle 21 upgrade.

An initial meeting was held with the licensee and Westinghouse, the Eagle 21 manufacturer, March 10, 1993, to discuss the Eagle 21 and bypass manifold replacement projects. The licensee described both projects and provided additional information to the staff. Open items identified by the staff requiring additional information from the licensee were as follows:

1. Eagle 21/ATWS Mitigation System Actuation Circuitry (AMSAC) Systems
2. Defense in depth/timing/emergency operating procedures
3. Input/output configuration
4. Factory acceptance test results
5. Functional requirements
6. Environmental effects

The above open items formed the basis for a design and site audit performed the week of April 5, 1993, at Westinghouse (Pittsburgh), Pacific Gas and Electric (San Francisco) and the Diablo Canyon plant site. Additional subjects discussed included the verification and validation (V&V) program with a concentration on the coding differences from previous Eagle 21 projects, electromagnetic interference/radio frequency interference (EMI/RFI), environmental qualification, calibration, training, plant equipment wiring, equipment installation, defense-in-depth and software (errors). The audit identified 10 additional open items requiring further information from the licensee.

The open issues included anomalies to the setpoint bases document, confirmation of TS and procedure revisions for temperature control by the cable spreading room HVAC system, Eagle 21 noise emissions test results, software revisions, cross calibration procedures, maintenance procedures (hardware and software), Westinghouse's defense-in-depth analysis, backup inputs, isolation device testing, diversity between AMSAC and Eagle 21, and Westinghouse drift term methodology.

A meeting was held with Westinghouse and the licensee in the Westinghouse offices in Rockville, Maryland on May 26, 1993. The purpose of this meeting was for the licensee to present additional technical information concerning Eagle 21/AMSAC systems diversity. Items discussed included software, hardware and a PRA study comparing core melt frequencies with varying degrees of Eagle 21 and AMSAC diversity. Subsequent meetings were held with the licensee on July 12 and August 10, 1993, to further discuss Eagle 21/AMSAC systems diversity requirements and discuss specific licensee and staff diversity review criteria as implemented for the Diablo Canyon Eagle 21/AMSAC systems installation. The staff and the licensee presented their proposed approaches for the assessment of diversity between digital systems and presented evaluation criteria particular to the review of the proposed Diablo Canyon amendment.

The Westinghouse 7100 reactor protection system currently installed at Diablo Canyon is a second-generation analog system manufactured in the early 1970's. The 7100 system consists of multiple sensors feeding four process protection channels. Each protection set (channel) contains analog process instrumentation for various parameters such as pressure, level, temperature and flow. The output of the process racks input to the reactor protection system logic for reactor trip and engineered safety features actuation. The process racks of the RPS are the portion of the RPS replaced by the Eagle 21 modification proposed by the licensee.

The Eagle 21 process protection system is a modular microprocessor-based system designed to replace existing analog process protection equipment. The Eagle 21 system is intended to be a form, fit and functional replacement for the existing 7100 analog protection system. The existing plant inputs (sensors) and outputs (RPS trip logic and engineered safety features actuation logic) will remain as currently installed. The Eagle 21 system is designed to limit rack field input/output wiring and termination modifications. The system is designed to be installed in the existing 7100 racks with only minor additional internal rack structural replacements and related modifications. The Eagle 21 installation preserves the existing 7100 rack terminal blocks and field cabling to minimize additional cable pulls and field connections external to the existing racks. All Eagle 21 rack subassemblies are tested as a field mock-up with prefabricated internal wiring, and are shipped in a "mock-up" configuration.

The following protection channels are handled by the Eagle 21 protection system:

1. Average temperature and delta temperature
2. Pressurizer pressure
3. Pressurizer water level
4. Steam flow and feedwater flow
5. Reactor coolant flow
6. Turbine impulse chamber pressure
7. Steam pressure
8. Containment pressure
9. Reactor coolant wide range temperature
10. Reactor coolant wide range pressure
11. Pressurizer vapor temperature
12. Steam generator narrow range water level

Unlike the analog system it replaces, the Eagle 21 system is not made up of individual modules to perform signal conditioning, calculation, trip logic or isolation function, but rather provides an integration of individual modules into a software-based digital system. The Eagle 21 system incorporates the following components:

1. Analog input module - powers the field sensors and performs signal conditioning

2. Loop calculation processor - performs all loop calculation functions (lead/lag, multiplication, comparator, etc.)

3. Partial trip output modules - provides trip and actuation logic

4. Analog output modules - provides isolated analog outputs

In addition, the Eagle 21 system is configured to perform automatic surveillance testing via a test sequence processor. The tester subsystem is channelized and rack mounted as opposed to the original singular test cart configuration.

The Eagle 21 system components are configured into three subsystems: loop processor subsystem, the tester subsystem, and an input/output (I/O) subsystem. The I/O subsystem includes customized analog input and contact input signal conditioning modules. These modules provide signal conditioning, signal conversion, isolation, buffering and termination points. They are configurable to accept various process inputs. Both modules provide signals to the loop processor subsystem and the tester subsystem as well as transferring raw analog inputs to the AMSAC system through qualified isolators.

The output portion of the I/O subsystem consists of analog output, contact output, and partial trip output modules. The purpose of these modules is to receive information from the loop processor subsystem and to construct analog, contact and trip logic outputs. All outputs to non-IE systems utilize Class IE isolation on their output signals (plant computer, control, etc).

The loop processor subsystem computes the algorithms and comparisons for the protective functions. The loop processor subsystem includes a digital filter processor, loop calculation processor, communication controller (data handler to tester subsystem), digital I/O module and a digital-to-analog (D/A) converter.

The loop calculation processor performs protective channel calculations on data input from the digital filter processor. The calculations include protective channel functions, data comparison to setpoint values, and initiation of trip signals.

The digital filter processor provides analog-to-digital conversion for signals input from the analog input modules. The outputs of the digital filter processor are then input to the loop calculation processor. The communication controller collects data from the loop calculation processor and transmits it to the tester subsystem. The digital I/O modules are used to process contact outputs, contact inputs and trip logic output signals. The D/A converter module is utilized to convert digital values from the loop calculation processor into analog values which are sent to analog output modules for further processing.

The tester subsystem provides the interface between the man-machine interface (MMI) and Eagle 21 protection system. The tester subsystem in conjunction with the MMI allows the operator to adjust setpoints and tuning constants. The performance of RPS surveillance tests can also be performed through the tester subsystem/MMI. The tester subsystem consists of the following components:

1. Test sequence processor (TSP) - The TSP reads information from the communications controller, digital I/O module and the MMI. The TSP writes information to the communications controller, digital I/O module, D/A converter and the MMI test unit thereby providing for status indication at the MMI and the creation of a signal injection and response bus (SIR) that allows the tester subsystem to control and test each module.

2. Communications controller - The communications controller receives information from the loop processor subsystem communication controller. The tester subsystem then uses this information to monitor the status of the loop calculation processor. The tester subsystem communication controller also provides a serial output to the MMI via the Eagle 21 test panel.

3. D/A converter module - The D/A converter module receives digital information from the TSP and converts it into high resolution analog signals that are then used for injecting test signals via the signal injection and response bus.

4. Digital I/O module - The digital I/O module receives information from the tester subsystem and provides signals to a contact output module that provides contacts for field devices.

The MMI is connected to the Eagle 21 system by attaching a cable assembly to the Eagle 21 test panel when testing is being done. The MMI communicates with the test sequence processor/communication controller and allows the operator to display or modify setpoints and tuning constants, display diagnostic information and output values, and assign points for trending (on-line). The MMI also can be used to obtain a hard copy printout of surveillance test results.

3.0 EVALUATION OF EAGLE 21 UPGRADE

The Eagle 21 software is modular in structure with all executable code contained in a module/subroutine and is programmed in a high-level structured language. The software design implementation includes no interrupts, re-entries, coding standards for high level and assembly language routines, high level module logic, or single task programs (no multi-tasking).

The software format is configured in layers. The main program, general purpose and standard protection functions module layers are developed such that they can be used in varied applications. The configuration module layer contains plant-specific information which configure the generic functions to project-specific applications. The configuration layer is application specific and, therefore, generally the only layer requiring additional coding for each project. As stated by the licensee, the above configuration provides for a significant amount of standardized code from project to project.

All executable software is supplied in programmable read only memory (PROM). Plant adjustable tuning parameters are stored in non-volatile memory for accessible onsite adjustment.

The software implementation at Diablo Canyon was shown to be identical to the Eagle 21 installations at the Sequoyah and Zion Nuclear Power Plants. The software at Diablo Canyon was found to be nearly identical functionally to that supplied to Sequoyah. The differences are in the configuration layer, the addition of a trip-time delay function at Diablo Canyon and a less conservative low-low steam generator trip function at Sequoyah.

The customer/vendor interface and the development of the system functional requirements for Diablo Canyon were reviewed by the staff. The staff has stated in previous digital system SERs that appropriate attention given to the system functional requirements can have a significant impact on the quality and safety of the installed software product. Recent reviews of digital modification packages have shown that failures in the functional and system specifications have had a significant impact on the success of system start-up and operation.

In the review of the Diablo Canyon installation, it was noted that the licensee played a significant part in supporting the staff's review and was highly involved in the development of the Eagle 21 modifications including procedures (maintenance, training and operations), system walkdowns, modification package development, and installed training equipment/modules well in advance of system installation and start-up. The staff finds this to be of benefit to the overall modification implementation.

The Westinghouse V&V Plan is documented by the licensee to be performed in accordance with Regulatory Guide (RG) 1.152, "Criteria for Programmable Digital Computer System Software in Safety-Related Systems of Nuclear Power Plants," and ANSI/IEEE/ANS 7-4.3.2-1982, "American National Standard Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations," and is intended to ensure the functionality of the system in accordance with the description in the functional requirements. The licensee stated that the software V&V effort was performed on generic Eagle 21 software. The generic software includes all possible process algorithms, whether they were utilized in the Diablo Canyon design or not.

The Westinghouse V&V Plan requires that the V&V organization be independent from the software development team. The independence of the V&V group includes separate lead engineers. Communication between the software development team and the V&V group is through traceable written test reports.

Westinghouse defines three types of reviews for software verification including design document review, code reviews and functional test reviews. Software testing is divided into two categories -- structural testing and functional testing. The choice of verification methods is based on the safety classification of the system and the chosen level of system software complexity. All of the Eagle 21 software was verified using level 1 (safety-related) criteria as defined by the Westinghouse V&V plan.

The validation process employed by Westinghouse is performed to demonstrate system functionality. The validation process includes three phases as follows:

1. Top-down functional requirements testing
2. Prudency review of the design and implementation
3. Specific MMI testing

Based on previous staff reviews of the Westinghouse Eagle 21 system V&V program, the review for Diablo Canyon concerned only differences in software implementation between Diablo Canyon and previously-approved Eagle 21 installations. The licensee stated that a total of four validation test reports were generated that were directly applicable to the Diablo Canyon design. The staff reviewed these reports and previous V&V problem reports and confirmed that the identified software errors have been satisfactorily resolved.

Based on the previous staff acceptance of the Westinghouse V&V plan, the similarity of the Diablo Canyon design to previously-approved designs and the demonstrated independence of the Westinghouse V&V effort, the staff finds the V&V plan as presented by the licensee to be acceptable.

The executing software is supplied in PROMs with the tunable constants provided in non-volatile RAM. All software code and software documentation is kept under management control at Westinghouse. Software changes other than field-adjustable parameters are to be made through a formal licensee design change process that utilizes Westinghouse as the librarian responsible for the storage and configuration control of the software. Should the software be revised, Westinghouse evaluates any anomalies resulting from the code change and evaluates the impact on the Eagle 21 system. Additionally, the revised software is also verified and validated as described in the Westinghouse design V&V plan. The staff finds the above-described configuration management approach consistent with R.G. 1.152 guidelines, and therefore, acceptable.

The staff reviewed the results of the factory acceptance testing to confirm that the Eagle 21 system will meet its performance requirements during normal operation. The test data was reviewed by Westinghouse and the licensee. The licensee concluded that the factory testing demonstrated that the Eagle 21 system meets or exceeds all performance requirements.

For Diablo Canyon, Units 1 and 2, the staff noted that racks 5, 9, 12 and 14 have been reserved for the MMI units which results in consolidation of rack inputs as compared to the existing 7100 protection racks. The staff also noted that the Diablo Canyon Unit 1 single board computer used for the digital filter processor experienced problems and failures in racks 2, 4, 7 and 16 during the factory testing. The problem was identified by the board manufacturer as a faulty component manufactured by Advanced Micro Devices (AMD). Other boards known to use the device were removed and examined for the presence of the AMD device. Affected boards were replaced and retested. The comparable Unit 2 racks were unaffected by the problem.

The AC/DC power supplies exhibited excessive failures during testing. The failure involved internal corrosion of capacitors. The failure of the capacitors caused excessive ripple on the power supply output. The failure of the capacitors may cause malfunctions in the microprocessor subsystem including "lock-up" or halting. The power supplies were repaired and successfully retested with capacitors from an alternate supplier.

The Unit 1 Eagle 21 system cabinets were found to include cable manufactured with polyvinyl chloride (PVC) insulation. PVC cabling is not sufficiently robust for Class 1E application. The cable was replaced and the racks were satisfactorily retested.

A problem was discovered in the displayed and printed version of a failure code as displayed by the MMI. The error was found to be in the coding of the print screen procedure. To correct the problem, new MMI PROMs were installed and satisfactorily tested.

Unit 2 testing revealed a timing problem with the clock chip used for the TSP and the MMI. The boards were reworked, the timing chip was replaced, and the boards were successfully retested.

The software for the TSP was found to contain two errors in the surveillance test equations (comparator trip setpoint). The software was revised and re-validated for the Diablo Canyon Eagle 21 system.

The front test panels for the Diablo Eagle 21 system were found to be prone to simultaneous shorting when touched because of the high gain, high input impedance of the signal conditioning circuitry. After initial reworks were unsuccessful, the test panels were replaced with test boards containing revised testpoints. The new boards were retested successfully and are included in the Diablo Canyon Eagle 21 system.

The Eagle 21 analog input (EAI) boards were initially assigned transmitters without regard to transmitter category. The possibility existed that transmitters required during and after an accident may be connected to the same board as transmitters not required to be operational. For some combinations, it was found that the EAI board would draw sufficient current to open the supply fuse before the regulator circuitry limited the output current. The EAI board is designed to handle the postulated current, and as a result, the Diablo Canyon Eagle 21 system EAI board fuses were replaced with fuses of higher current capacity to prevent the unavailability of the connected transmitters.

The retaining bars for the microprocessor card cage were manufactured without a foam strip on the inside of the retaining bar. The foam strip provides a constant pressure and reduces the gap between the card edge and retaining bar, thereby reducing the possibility of the card coming loose during a seismic event. Foam strips were added at the completion of acceptance testing for the Diablo Canyon Eagle 21 system.

Based on the above corrective actions implemented by the manufacturer and licensee, the staff finds the identified Eagle 21 system failures to be properly corrected and incorporated into the Diablo Canyon installation.

The Eagle 21 system is qualified per WCAP-8687, Supplements 2-E69A, 2-E69B and 2-E69C "Equipment Qualification Test Reports." The Westinghouse test methodology conforms to IEEE 323-1974, "IEEE Standard for Qualifying Class IE Equipment for Nuclear Generating Stations," and was previously approved by the staff.

The Eagle 21 and AMSAC digital systems are located in the Diablo Canyon cable spreading room. The licensee stated that the maximum qualification temperature range (abnormal conditions) for Eagle 21 was 82 to 120 degrees F with the normal operating temperature range specified as 60 to 82 degrees F. A review of the Diablo Canyon TS revealed that the action statement for temperature monitoring of the cable spreading room allows a temperature of up to 133 degrees F for 8 hours with a nominal temperature of less than or equal to 103 degrees F. Based on the above, the licensee initiated procedural changes to ensure that the cable spreading room temperature is maintained within the above Eagle 21/AMSAC systems temperature qualification limits, and to correct equipment identification numbers. The staff noted that the HVAC system for the cable spreading room is non-IE (non-IE fans and chiller) with the capability to manually realign to a class IE system. This design has previously been accepted by the staff.

The Eagle 21 equipment racks and components were subject to multi-axis, multi-frequency seismic inputs in accordance with Regulatory Guide 1.100, "Seismic Qualification of Electric and Mechanical Equipment for Nuclear Power Plants." The Eagle 21 components are mounted in standard RPS cabinets and were generically qualified via testing of a free-standing bay lineup. The existing protection racks at Diablo Canyon were noted to have a significant number of rigid conduits with top mounted connections in a bay line-up of up to eight units. The top-mounted connections and expanded bay configuration required additional analysis by Westinghouse. The evaluation concluded that the additional loading due to cabinet-to-conduit loading and the proposed eight bay configuration are acceptable. Additionally, for the AMSAC functions (isolation) of the Eagle 21, Westinghouse provided seismic qualification for the current loop input isolation module and termination module for use in interfacing between the Eagle 21 and AMSAC systems. The Diablo Canyon installation also includes rack-mounted MMI components which were evaluated for structural integrity and found to be acceptable.

Based on the above analysis results, the staff finds that the seismic qualification of the Diablo Canyon Eagle 21 system conforms to RG 1.100 and IEEE 344-1975; and therefore, envelopes the proposed Diablo Canyon installation.

Based on the staff's concern that a potential exists for random and unpredictable spurious effects on safety systems due to the ambient EMI/RFI environment into which the system is installed, the licensee performed onsite mapping of the cable spreading room environment to determine the worst-case EMI/RFI noise profile. The frequency range of the testing performed was from

DC to 1GHZ. The following tests were performed in the cable spreading room in accordance with MIL-STD-461 and MIL-STD-462:

1. CE01-Conducted Emissions, Power Leads, 30 HZ to 15KHZ
2. CE03-Conducted Emissions, Power Leads, 15KHZ to 50MHZ
3. REXX-Radiated Emissions, DC Magnetic Field
4. RE01-Radiated Emissions, AC Magnetic Field, 30 HZ to 50KHZ
5. RE02-Radiated Emissions, Electric Field, 14KHZ to 1GHZ
6. RE02-Radiated Emissions, Electric Field, Hand-held Radio Profile

Based on the site survey test results, the licensee indicated that the Eagle 21 system is site-qualified for installation in the Diablo Canyon environment. Based on operating experience of existing Eagle 21 installations, and the continued prohibition of hand-held radios and portable telephones in the cable spreading room, the staff finds the EMI/RFI qualification of Eagle 21 to be satisfactory for installation at Diablo Canyon.

The staff also requested that the licensee evaluate the AMSAC system for any adverse emission level susceptability related to the installation of the Eagle 21 system in close proximity to the AMSAC installation. As a result of emissions testing performed on Eagle 21 and the evaluation by Westinghouse, the licensee concluded that the increase in background readings was insignificant and unlikely to affect nearby equipment. Based on the above, the staff concludes that Eagle 21 noise interference with AMSAC has been properly addressed.

Electrostatic discharge (ESD) was evaluated by the staff during previous Eagle 21 reviews. For Diablo Canyon, the staff confirmed that similar ESD precautions are implemented at Diablo Canyon and that the Eagle 21 system continues to show no reported susceptibility to ESD. The licensee also indicated plans to replace the existing inverter and batteries supplying Eagle 21 in order to increase available power.

3.1 <u>Eagle 21 Defense-in-Depth</u>

The reactor protection system is designed to automatically initiate the operation of the appropriate systems including the reactivity control system to provide for normal and emergceny reactor shutdown. The RPS is designed such that it provides for high functional reliability and such that it fails into a safe state. The redundancy and independence utilized in the design of the RPS is intended to assure that no single failure results in a loss of protection function. Functional diversity, or diversity in component design and principles of operation are to be implemented to the extent practical in order to prevent the loss of the protection function.

Concerns identified by the staff involving the implementation of digital systems in nuclear power plants include (1) the inability to specify or demonstrate software reliability (quantitative measurement), including unintended functions and common mode errors; (2) environmental qualification; (3) commercial dedication (hardware and software); and (4) licensee expertise for installation, maintenance, troubleshooting, and configuration management.

Defense-in-depth is considered by the staff to be a combination of design features incorporating overlapping and redundant capabilities such as diversity, redundancy, reliability, and performance in order to compensate for postulated safety system weaknesses. For a defense-in-depth approach to be effective, the echelons of defense must be available to provide a backup function when faced with postulated failures. In determining when an adequate level of defense-in-depth has been achieved, an evaluation is performed of the degree of interdependence that is acceptable and what means are available (for example, surveillance, maintenance, quality and reliability) to maintain an adequate level of safety.

The Diablo Canyon Eagle 21 system is a software-based system and differs significantly from the analog system currently installed. The Eagle 21 system utilizes more data transmission functions and process equipment than the 7100 system that it will replace.

The staff noted in its review that the Eagle 21 RPS uses the same software and hardware for all four safety channels. The staff postulated that a hardware design error, a software design error or software programming error may result in a common mode or common cause failure in redundant equipment. The staff's concern with the proposed use of digital computer technology in the Diablo Canyon RPS, as with any comparable digital system retrofit, is that a safety-significant common mode failure may result in an inoperable RPS. The staff review considers those features on a plant specific basis available to provide defense-in-depth in the event of such an error. A key point is that a software design or programming error may defeat the redundancy achieved by the installed hardware architecture. Because of the above concern, the staff placed particular emphasis on defending against the propagation of common mode failures between safety functions, or the mitigation of such a failure through a defense-in-depth approach.

One of the first efforts by the staff to address defense-in-depth against potential common mode failures in digital systems occurred in the review of the Westinghouse RESAR-414 design. The results of this review and the methodology used to perform the review were published in NUREG-0493, "A Defense-in-Depth and Diversity Assessment of the RESAR-414 Integrated Protection System." NUREG-0493 discussed common mode failures and the defense against such failures by providing attention to the quality and reliability in the design, manufacturing, and operation of a digital system, and the use of diversity to minimize the risk of common mode failure.

The forms of diversity recognized by the staff, for this review, in order to address common mode failure concerns are signal diversity, equipment diversity, aspect diversity (energization states or logic states), functional diversity, software diversity and people diversity.

Because the Eagle 21 RPS installation at Diablo Canyon includes common hardware and software, the staff considered a common mode error, particularly in software, to be a credible failure requiring further analysis. Based on the above concern, the staff requested that the licensee evaluate the defense-in-depth capability of the proposed Eagle 21 RPS in order to demonstrate the robustness of the reactor protection system when faced with a potential common mode failure across redundant safety trains.

The above staff concern is similar to those expressed in previous evaluations in that a common mode software error is considered credible, and because the Eagle 21 system processes all inputs through an identical computer module in each protection set. However, unlike earlier Eagle 21 upgrades, the licensee stated that rack consolidation was minimized for the Diablo Canyon installation. Although rack vulnerabilities (module to module interactions) exist for the Diablo Canyon installation, a software common mode failure remains the primary concern as it was for previous Eagle 21 RPS upgrades. The licensee stated that the Eagle 21 system is at least as reliable when compared to the existing 7100 analog protection sets. The licensee supported this statement based on the satisfactory operating experience of existing Eagle 21 installations. Additionally, operational and surveillance features of Eagle 21 provide enhancements to reliability not available in the existing 7100 system. However, the question of a software common mode failure remains.

In response to the defense-in-depth issue, the licensee responded by providing WCAP-12813-R3, "Summary Report Eagle 21 Process Protection System Upgrade for Diable Canyon Power Plant Units 1 and 2." The defense-in-depth assessment described diverse protection system responses, indications and alarms that are available should the Eagle 21 system fail. The licensee divided the licensing basis accidents and events into four categories as follows:

1. Events that do not require Eagle 21 for primary or backup protection

2. Events that do not require Eagle 21 for primary protection but assume Eagle 21 protection system signals for backup

3. Events that require Eagle 21 for primary protection signals but will receive automatic backup protection from systems other than Eagle 21

4. Events that assume Eagle 21 for primary and backup protection signals for some aspect of automatic protection

For events that do not require Eagle 21 for primary or backup protection (Category 1), the licensee stated that a common mode failure of the Eagle 21 system will not prevent an automatic safety function. The licensee stated that events in this category receive Eagle 21 protection signals, but that the primary protection response is derived from a system other than Eagle 21.

For events that do not require Eagle 21 for primary protection but assume Eagle 21 for backup protection (Category 2), the licensee stated that these particular events are unaffected by a common mode failure of the Eagle 21 system since the primary protection is derived through systems other than Eagle 21.

Licensing basis events (Category 3) that require Eagle 21 for primary protection signals but receive automatic backup signals from systems other than Eagle 21, will be affected by a common mode failure of the Eagle 21 system. With the exception of RCCA withdrawal and main feedline break events, all the events in this category have been analyzed as ATWS events. The licensee stated that with the reactor above 40% power, the AMSAC system provides the required protective functions. The licensee stated that with the reactor above 50% power, a reactor trip will occur independent of Eagle 21 (P9 permissive) on turbine trip. The licensing basis events that take credit for AMSAC to provide the necessary protection functions are:

1. Loss of normal feedwater
2. Loss of offsite power to station auxiliaries
3. Major rupture of a main feedwater pipe (below the C20 setpoint, operator action is required)

The licensing basis events that require Eagle 21 for primary and backup protection for some aspect of the event (Category 4), are:

1. Loss of forced reactor coolant flow
2. Accidental depressurization of the reactor coolant system
3. Loss of coolant accident (small-and-large break LOCA)
4. Steam line break events
5. Steam generator tube rupture

The licensee stated that for the above events requiring Eagle 21 for primary and backup protection, it was determined that a diverse means of automatically mitigating the transient or providing plant indications (annunciators or indications) are available with sufficient procedural guidance for an operator to diagnose the event in a timely manner and bring the plant to a safe shutdown condition.

The staff evaluated the diverse backup actuation and indication available in the control room, as referenced by the licensee for the four event categories to cope with a potential common-mode failure of the Eagle 21 reactor protection system concurrent with a Chapter 15 licensing design basis event. Based on the licensee's evaluation, the staff determined that the license's defense-in-depth analysis provides reasonable assurance that should a common mode failure of the Eagle 21 system occur, there exists appropriate diverse means via AMSAC to mitigate the events. Eagle 21/AMSAC systems diversity is discussed further below.

3.2 Eagle 21/AMSAC Diversity

The licensees defense-in-depth evaluation for a common mode failure of the Eagle 21 RPS is in part based on the previously accepted diversity assessment by the staff for the Westinghouse designed digital AMSAC system installed at Diablo Canyon. The licensee's defense-in depth evaluation takes credit for AMSAC backup protection for the following Chapter 15 events following a postulated common-mode failure of the Eagle 21 RPS:

1. Loss of normal feedwater
2. Loss of offsite power to station auxiliaries
3. Major rupture of a main feedwater pipe

For these events, the Eagle 21 system provides different primary protection functions than the AMSAC system in that Eagle 21 initiates rod insertion while AMSAC initiates turbine trip/auxiliary feedwater flow.

The staff noted that the proposed Eagle 21 and existing AMSAC systems at Diablo Canyon share many common design attributes. The following commonalities/similarities were initially noted between the proposed Eagle 21 and installed AMSAC systems:

1. Common software language/compiler/linker/locator
2. Design team (software)
3. Design team (hardware)
4. A/D Conversion (multiplexing)
5. Input signal conditioning
6. Microprocessors
7. System power supplies
8. Common active components (buffers, drivers, peripheral interfaces, isolation amplifiers, etc.).

The staff also noted design differences between the Eagle 21 and AMSAC systems, specifically with regard to system complexity. The AMSAC system is much simpler than Eagle 21 in that it has a single input (steam generator level) and two outputs (turbine trip and auxiliary feedwater initiation) compared to multiple inputs and outputs for Eagle 21.

However, because of the above initially-identified common elements between the proposed Westinghouse Eagle 21 digital RPS and the existing Westinghouse digital AMSAC system installed at Diablo Canyon, the staff performed a more in-depth diversity/defense-in-depth evaluation than had been required for previously-reviewed Eagle 21 RPS retrofits (Zion and Sequoyah). For previous Eagle 21 defense-in-depth assessments that took credit for AMSAC as a backup to Eagle 21 for reactor protection functions, the installed AMSAC system was shown to be adequately diverse from the reactor protection system in accordance with the requirements of the ATWS rule, 10 CFR 50.62. This was based on use of equipment provided by different vendors when both the AMSAC and RPS systems were digitally based. For Westinghouse-designed PWRs, the ATWS rule specifically requires ATWS mitigation capability with diverse equipment from sensor output to final actuation device. For example, the staff evaluation of diversity for Zion against the requirements of 10 CFR 50.62 recognizes that a different AMSAC system vendor and supplier, different isolation devices, and completely diverse logic modules were selected when compared to the existing RPS. This approach also applied to the subsequent proposed installation of the Eagle 21 system at Zion because diversity in vendor/supplier, and thus equipment, was maintained at a high level.

The staff's previous AMSAC evaluation for Diablo Canyon against 10 CFR 50.62 noted that the AMSAC system was microprocessor-based and stated that in the areas of design, equipment, and manufacturing, it was diverse from the installed 7100 analog protection sets. The staff's evaluation also stated that where similar components were to be used, for example relays, the AMSAC system would utilize components of a different make and manufacturer and that maximum available independence between AMSAC and RPS power supplies would be provided.

As a result of the staff's diversity evaluation for the Diablo Canyon Eagle 21/AMSAC systems, the staff requested the licensee to provide an in-depth assessment of the diversity between the Eagle 21/AMSAC systems and to determine if the present AMSAC system will continue to meet the requirements of 10 CFR 50.62 following the installation of the Eagle 21 system. The licensee responded by providing WCAP-13821, "Eagle 21/AMSAC Diversity Evaluation." Within this report, each item of similarity noted between the AMSAC and Eagle 21 systems was evaluated by the licensee.

As previously noted in the defense-in-depth discussion, the staff's concern with the proposed Eagle 21/AMSAC systems installation is to ensure that any potential common mode failures introduced by the installation of the Eagle 21 at Diablo Canyon are bounded by plant design, analysis or procedures such that the requirements of 10 CFR 50.62 continue to be met, and the conclusions of the licensee's defense-in-depth analysis remain valid.

The staff assessed the diversity of the Eagle 21/AMSAC systems in a manner similar to the defense-in-depth analysis performed on the Eagle 21 itself. This assessment considered compliance with General Design Criteria 22 and 23; IEEE 603-1980 and IEEE 603-1991, "Standard Criteria for Safety Systems for Nuclear Power Generating Stations;" IEEE 379-1977, "Application of the Single Failure Criterion to Nuclear Power Generating Station Class IE Systems;" ANSI/IEEE-ANS-7.4.3.2-1982, "American National Standard Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations;" and NUREG-0493, "A Defense-in-Depth and Diversity Assessment of the RESAR-414 Integrated Protection System." The methodology used by the staff to perform the diversity assessment of the Eagle 21/AMSAC systems included the guidance outlined in NUREG-0493 in that common functional elements (blocks) were identified, the failures of these common elements/blocks were postulated, and the results of those failures were addressed in the system response to the design basis events.

The staff's evaluation centered on the safety significance of common-mode failure mechanisms in the proposed Eagle 21/AMSAC systems by the inclusion of identical/similar hardware and software in both systems. The staff determined that to be acceptable, the postulated Eagle 21/AMSAC systems common-mode failure susceptibility must be adequately compensated for by sufficient quality, reliability and diversity. To demonstrate adequate quality, the licensee must demonstrate an integrated development process for the Eagle 21/AMSAC systems in order to address hardware and software configuration management for the life of the plant, and utilize design and process requirements (at a high level). The various specific aspects of the Eagle 21/AMSAC systems diversity assessment are discussed below.

Organizational (People) Diversity

The licensee addressed the organizational (people) diversity similarities and demonstrated that the Eagle 21/AMSAC design teams (both hardware and software) were sufficiently separate in that they were developed by essentially separate design groups with independent designers, and under different project managers. The staff considers this an acceptable level of people diversity.

Power Supplies

The licensee addressed the identical power supply components in both AMSAC and Eagle 21 by demonstrating adequate aspect diversity. The licensee indicated that the failure mode for AMSAC (fail "as is") versus that for Eagle 21 (fail safe), on loss of power are different, thereby confirming the independence of the Eagle 21 and AMSAC power supplies. Based on the licensee's evaluation, the staff finds the power supply implementation, and the demonstrated aspect diversity at Diablo Canyon acceptable.

Microprocessor Diversity

The Eagle 21 and AMSAC systems at Diablo Canyon both utilize microprocessors from the same microprocessor family (manufacturer) for the Eagle 21 loop calculation processor and the AMSAC actuation loop processor. The licensee stated that although some external interfaces, such as the instruction sets, are the same, the designs of both processors are sufficiently different to meet the requirements of 10 CFR 50.62. The licensee identified differences in manufacturing processes, the difference in internal architecture for both processors, and differences in external interface methodologies. Based on the indicated differences in the manufacturing process, architecture, interfaces, and performance parameters, and the proven reliability of the microprocessors, the staff finds the microprocessor implementation for the AMSAC/Eagle 21 systems to be acceptable.

Analog/Digital Conversion

The A/D boards for both AMSAC and Eagle 21 share a number of identical components including the A/D converter. The licensee confirmed that the components performing the A/D conversion are the same. However, although the A/D conversion process is performed by identical components, the licensee indicated that the common components are being supplied by varying manufacturers, are simple, fully tested devices, and have been shown to be reliable based on substantial operating experience. The software execution for the A/D conversion process is different between AMSAC and Eagle 21 as referenced by the licensee. The A/D conversion is performed by separate circuit board assemblies with physical differences in layout and assembly. Additionally, the licensee stated that should a common-mode failure occur in the A/D conversion, there are diagnostics available that will inform the operator of such failures. Based on the licensees evaluation of the similarity of components, the staff considers the A/D conversion implementation at Diablo Canyon to be acceptable.

Signal Conditioning

The input signal conditioning boards for both AMSAC and Eagle 21 share a common isolation amplifier. The isolation amplifier utilized for input signal conditioning is in common use throughout the industry, and as stated by the licensee has been shown through operating experience to be highly reliable. This isolation amplifier is manufactured by the same supplier. The designers did not believe that it was practical to maintain the equipment diversity of both AMSAC and Eagle 21 at this level. The licensee's evaluation stated that should a common-mode failure occur within the isolation amplifiers (signal conditioning), the Eagle 21 system will continue to provide a reactor trip (fail-safe aspect). Should the isolation amplifiers fail high or low, the failure is detectable by the A/D converter limit checks with the Eagle 21/AMSAC systems generating a trouble alarm. Amplifier drift was also addressed by the licensee and shown to be detectable, or result in a system trip. Based on the licensee's evaluation, the staff finds the input signal conditioning similarities to be acceptable.

Common Active Components

Additional common active components were used in both AMSAC and Eagle 21 - approximately one third of the components for the multibus boards, but only one component on the I/O boards. The licensee stated that the manufacturers of these components are different and the components are common-use industry devices. Based on the manufacturing differences, differences in architecture, reliability of the involved boards, variability of suppliers for the identified components, and the level at which the commonalities are identified (component level), the staff finds the inclusion of the common active components to be acceptable.

Software Diversity

The AMSAC and Eagle 21 systems were found to share the same software language and compiler. The staff concern was that the dependence on the AMSAC system as a diverse backup means for selected Chapter 15 events (loss of normal feedwater, loss of offsite power to the station auxiliaries, and major rupture of a main feedwater pipe) may not be appropriate based on the possible common mode failure due to errors in shared software language between both systems. Such a software language error could result in the failure of both Eagle 21 and AMSAC in other than their design failure modes.

The licensee stated that there are no common software modules shared by the two systems. The AMSAC software was developed by a design team separate from the Eagle 21 design team. Separate libraries and management controls are maintained by Westinghouse to ensure the independence of the AMSAC/Eagle 21 software. Eagle 21 V&V process was performed in accordance with RG 1.152 and ANSI/IEEE 7-4.3.2-1982 and has been accepted by the staff. The Eagle 21 V&V team was independent of the AMSAC/Eagle 21 systems design teams. Although the AMSAC system software was not required to undergo the level of V&V applied to Eagle

21 because it is not safety related, the licensee stated that independent source code reviews and validation testing were performed on the AMSAC system software.

To demonstrate the diversity of the software implementation in both the AMSAC and Eagle 21 systems, a thread audit was performed for the low-low steam generator water level input for both systems. The side-by-side comparison of the software demonstrated that there was no apparent common source code between the Eagle 21 and AMSAC systems. Similar software functions were implemented differently for each system. The thread audit demonstrated that the algorithms for steam generator low-low level are different.

The use of the same software language for both Eagle 21 and AMSAC was justified by the licensee in that the vendor has had extensive experience using the language and tools (10 years), and the language has been used extensively in a variety of products. Because of this extensive vendor experience, the use of the same language was considered a reliability enhancement by the vendor and licensee. The licensee also stated that if the software language is the same for both systems, but is programmed to perform different functions, the result should be an object code that is different (diverse). This was demonstrated in the thread audit for the steam generator low-low water level input function for both the AMSAC and Eagle 21 systems.

The licensee also stated that based on the demonstrated system level aspect diversity (hardware), a common-mode software or compiler error will not prevent both the Eagle 21 and AMSAC systems from performing their safety function by failing to their design failure mode.

Upon consideration of the organizational, functional (software algorithm and actuation), and aspect diversity of the proposed Diablo Canyon Eagle 21/AMSAC systems, the staff finds that the licensee has demonstrated that sufficiently diverse means to safely shutdown the reactor are provided in the event of postulated software common-mode failures.

3.3 <u>Summary on Eagle 21 Upgrade</u>

In summary, the staff finds that a sufficient level of diversity has been demonstrated for the Eagle 21/AMSAC digital systems at Diablo Canyon based on:

1. Design diversity--achieved based on the difference in complexity between the AMSAC and Eagle 21 digital systems architecture, i.e. AMSAC is a simple one-input/two output configuration compared to the multiple inputs/outputs and more complex multiplexing of Eagle 21.

2. Functional diversity--achieved between Eagle 21 and AMSAC based on different primary reactor protection functions, i.e., AMSAC initiates turbine trip and auxiliary feedwater (AFW) flow while Eagle 21 initiates control rod insertion. Further, while Eagle 21 also includes turbine trip and AFW flow initiation functions, differences in the timing of

these functions between AMSAC and Eagle 21 and corresponding algorithm differences demonstrate sufficient software diversity.

3. Aspect diversity--achieved based on the differences in failure modes between AMSAC and Eagle 21, i.e. fail "as-is" for AMSAC versus "fail safe" for Eagle 21.

4. People diversity--demonstrated by the substantial differences in the composition of the design and V&V teams for the Eagle 21 versus the AMSAC system.

Based on the above, the staff concludes that the intent of the requirements of 10 CFR 50.62 for ensuring ATWS mitigation system diversity from the RPS have been satisfied, and the use of the Westinghouse-designed Eagle 21 RPS in conjunction with the Westinghouse-designed digital AMSAC system is acceptable for Diablo Canyon.

4.0 EVALUATION OF RTD BYPASS ELIMINATION

In addition to the installation of the Eagle 21 RPS at Diablo Canyon, the licensee has also requested a TS amendment for the removal of the resistance temperature detector (RTD) bypass manifold system. The modification replaces the existing RTD bypass manifold system with thermowell-mounted narrow range, fast response, dual-element RTDs located directly in the reactor coolant system piping. The present reactor coolant temperature measurement system uses coolant scoops in the primary coolant to divert a portion of the reactor coolant into the bypass manifold loops. The RTDs for T-hot and T-cold temperature measurement are located within the bypass manifolds and are inserted directly into the reactor coolant bypass flow without thermowells. Separate bypass loops are provided for each reactor coolant loop such that individual T-hot and T-cold loop temperature signals can be developed for use in the reactor protection and control systems.

The bypass manifold system was originally developed to resolve concerns with temperature streaming (temperature gradients) within the hot leg primary coolant. The temperature streaming experienced in the hot leg piping was a result of incomplete mixing of the coolant leaving various regions of the reactor core at different temperatures. The bypass manifold system compensates for the temperature streaming by sampling the primary coolant through scoop tubes and mixing the primary coolant within the bypass manifold to develop an average RCS temperature. The bypass manifold system also limits high velocity coolant flow to the RTDs and allows RTD replacement without the need to drain down the reactor coolant system.

Incorporation of the bypass manifold system, however, created its own set of operational problems. Examples have included primary leakage through valves or flanges, and the interruption of bypass flow due to valve stem failure. Additionally, the bypass manifold piping contributes to increased radiation exposure when maintenance must be performed on the bypass manifolds system.

The RTD bypass elimination affects the FSAR Chapter 15 design basis events safety analysis because of the different response time characteristics for the new thermowell-mounted RTDs, instrumentation uncertainties associated with the new RTDs and the signal processing performed by the new Eagle 21 RPS. As a result, the T-average and delta-T signal inputs to the RPS and other nonsafety-related control systems are also modified.

The modified system hot leg temperature measurement for each loop will be obtained using three fast-response, narrow-range, dual-element RTDs mounted in thermowells spaced at approximately 120 degrees around the reactor coolant pipe to compensate for the temperature streaming in the hot leg. The readings are electronically-averaged to provide T-hot and include a bias for hot leg temperature streaming. This modified RTD arrangement will perform the same sampling/temperature averaging function as the original bypass manifold system. The removal of the bypass manifold piping will not effect the single wide-range RTD installed at each steam generator. This RTD will continue to be used to monitor hot leg temperature during startup, shutdown and post accident conditions.

The cold leg temperature measurement will be obtained by the average of one narrow-range dual-element RTD located at the discharge of the reactor coolant pump. Because of the mixing effects of the reactor coolant pump, only one RTD has been considered necessary for cold leg temperature measurement. However, for the Diablo Canyon installation, the licensee has included a bias to account for expected temperature streaming in the cold leg. The streaming data taken at plants similar to Diablo Canyon indicates that cold leg streaming should be included in the analysis. The new dual-element RTD replaces the cold leg RTDs previously mounted in the bypass manifold. The existing bypass manifold return line nozzles will be capped. The licensee stated that the RTD bypass manifold removal will not effect the single wide range RTD installed at the reactor coolant pump. This RTD will also continue to be used to monitor cold leg temperatures during plant startup, shutdown and post-accident conditions.

The replacement RTDs are provided by Weed Instrument Company, Inc., and as stated previously, are dual element RTDs mounted in thermowells. The spare element of each RTD will be terminated such that the spare element can be switched oneline in the event of a RTD failure.

The new thermowell-mounted RTDs have a response time essentially equal to the allowed time for the old bypass piping transport, thermal lag and direct immersion RTDs (about four seconds). The four-second response time noted for the new thermowell mounted RTDs is supported by industry experience. The two-second electronics delay specified by the licensee is increased over that referenced for the original bypass manifold system to account for the added delay of the Eagle 21 system. The licensee also increased the Chapter 15 accident analyses response time assumption value to 7 seconds to provide additional margin. The licensee will verify the response time of the new RTDs using loop current step response (LCSR) methodology following RTD installation in the plant. The LCSR methodology has been evaluated previously and is an industry-recognized onsite method for confirming RTD response times.

The RTD input signals are averaged by the Eagle 21 system. The outputs from the reactor coolant loop RTDs provide the signals needed to calculate the arithmetic average loop temperature (T-average) and the loop differential temperature (delta T). The T-average and delta-T inputs for plant control systems are derived from the same set of RPS RTDs. The T-average and delta-T values are provided to the plant control system through isolation devices.

The failure of a RTD is automatically detected by the Eagle 21 system through range checks and comparisons to a specified temperature range as described below. Each hot leg temperature signal (T-hot) in each loop is subjected to a range check. An estimated hot leg temperature T(est) is then derived from each T-hot signal by applying a power-corrected hot leg temperature streaming bias. The Eagle 21 system then uses the resulting T(est) signals to calculate an estimated average hot leg temperature for the corresponding loop, T(est,ave). The three T(est) are then compared to the corresponding loop T(est,ave) to determine whether they agree within a specified temperature range (delta-H). If the T(est) temperatures agree within the specified range of T(est,ave), the group quality is set to "Good" and the loop average hot leg temperature T(hot,ave) is set to the average of the three estimated average hot leg temperatures. If the estimated average hot leg temperature signal does not agree within the specified range of estimated average hot leg temperature, the value furthest from T(est,ave) is deleted and the quality of the deleted signal is set to "Poor." The remaining signals are then checked for consistency. If the two signals pass the consistency check, the group value, T(hot,ave), is set to the average of the two signals, and the group quality is set to "Poor." If the two remaining signals are not consistent, the T(hot,ave) value is set to the average of the two signals, and the group quality is set to "Bad" with the quality of the individual signals set to "Poor." The second element of each RTD is a spare, and is available as a replacement for a failed RTD.

The cold leg temperature input signals from the dual element RTD in each cold leg are also subjected to range and consistency checks, and then averaged to provide a group value for T(cold). If these signals agree within an acceptable interval (delta), the group quality is set to "Good." If the signals do not agree within the specified range the group quality is set to "Bad" and the individual input signals are set to "Poor." One cold leg temperature input signal per loop may be deleted manually. The remaining T (cold) input signals will provide the loop T(cold) temperature signal.

The delta-H parameter for each loop is based upon temperature distribution tests within the hot leg and is entered via the MMI. The cold leg delta parameter for each loop is based on operating experience and is also entered through the MMI.

The staff noted that the setpoint methodology document for Diablo Canyon did not reflect Eagle 21 system operation. The licensee provided the required clarification by modifying the setpoint methodology consistent with implementation of the Eagle 21 system.

Annunciation for the new RTDs is provided in the control room in the form of "trouble" and "RTD failure" alarms. The trouble alarm is actuated when the T-ave group value is set to "Poor." The RTD failure alarm is activated when a RTD failure is detected by the Eagle 21 system.

The licensee stated that following the initial thermowell RTD cross calibration, the calibration reference will consist of the average of the RTD temperatures. The staff has expressed concern in the past that the use of an average RTD value as a reference for cross calibration instead of a calibrated reference may lead to a net drift of the average temperature value indicated by the RTDs over time should the installed RTDs drift systematically. Studies have indicated that the installed RTD drift is random. Therefore, without a reference, the cross calibration will not detect common mode (systematic) drift and will provide information on the consistency and not the accuracy of the installed RTDs. In response to the staffs concern, the licensee provided justification for RTD calibration without a reference based on acceptable operational experience, but is continuing to evaluate cross calibration techniques on a generic basis. The staff finds the proposed RTD calibration means acceptable.

4.1 RTD Bypass System Removal

4.1.1 Current Method

The current method of measuring the hot and cold leg reactor coolant temperatures uses a RTD bypass system. The hot and cold leg temperature readings from each coolant loop are used for protection and control system inputs. The RTD bypass system was designed to address temperature streaming in the hot legs and, by use of shutoff valves, to allow replacement of the direct immersion narrow-range RTDs without draindown of the Reactor Coolant System (RCS). For increased accuracy in measuring the hot leg temperatures, sampling scoops were placed in each hot leg at three locations of a hot leg cross-section 120 degrees apart. Each scoop has five orifices which sample the hot leg flow along the leading edge of the scoop. The flow from the scoops is piped to a manifold where a direct immersion RTD measures the average temperature of the flow from the scoops. This bypass flow is routed back to downstream of the steam generator. The cold leg temperature is measured in a similar manner except that no scoops are used, as temperature streaming is not a problem due to the mixing action of the RCS pump.

4.1.2 New Method

The modification in the new method proposed for measuring the hot and cold leg temperatures removes the hot and cold leg manifolds and all associated piping and valves. The new method uses narrow-range, dual element, fast response RTDs manufactured by the Weed Company. Three hot leg dual element RTDs are installed in thermowells at an insertion depth that is at the middle hole location of the former RTD bypass scoops, which is nominally 4 inches. One of the RTD elements is active and the other is an installed spare. The RTDs are in a single plane, 120 degrees apart. For each loop, the three temperatures are electronically averaged by the Eagle 21 process protection system to produce an average hot leg temperature (Thot) that accounts for the temperature streaming effects. The cold leg measurement on each loop is measured by a dual element RTD installed in a thermowell mounted in a new penetration nozzle at the discharge of the reactor coolant pump. The Eagle 21 process protection system averages the two RTDs to represent the cold leg temperature (Tcold).

4.1.3 Analysis

The licensee presented information (Ref. 1) regarding the accuracy of the new method for measuring the hot leg temperature and also information regarding the response time of the new RTD measurement system. The response time and accuracy affect the accident analyses.

4.1.4 RTD Response Time

As shown in the tabulation below, the response time for overtemperature delta-T for the proposed system has some gains and losses compared to the existing RTD bypass system. The total response time of the proposed system is increased over the existing system, 7.0 seconds vs. 6.0 seconds, to provide margin.

RESPONSE TIME BREAKDOWN FOR RCS TEMPERATURE MEASUREMENT

	Current RTD Bypass	Fast Response Thermowell RTD
RTD Bypass and Thermal Lag (sec)	2.0	N/A
RTD Response Time (sec)	2.5	4.0
RTD Filter Time Constant (sec)	0.0	0.0
Electronics Delay (sec)	1.5	2.0
Margin (sec)	-	1.0
Total Response Time (sec)	6.0	7.0

The licensee reported that the RTD response times will be checked as part of the reactor trip system instrumentation (Technical Specification Item 7, Table 3.3-2). The surveillance requirements state that response time checks are required at each refueling cycle. NUREG-0809 (Ref. 4) and NUREG/CR-5560 (Ref. 5) have pointed out that RTD response times have been known to degrade and that the Loop Current Step Response (LCSR) methodology is the recommended on-site method for checking RTD response times. In NUREG/CR-5560 it is noted that the LCSR method provides results that are within 10 percent accuracy. The licensee plans to use the LCSR method for checking the RTD response time at each refueling cycle and stated that their survellance test requires use of 110% of the measured response time to account for the inaccuracy of the LCSR method.

Based on the above information the staff finds that the RTD response time has been addressed in an acceptable manner.

4.1.5 RTD Uncertainty

The new method of measuring each hot leg temperature with three thermowell RTDs (one in each scoop) has been evaluated to at least as accurate as the existing bypass system with three scoops in each hot leg and one RTD measurement. The new RTD thermowell which measures temperature at the mid point of each scoop may have a small streaming error relative to the former scoop flow measurement because of a temperature gradient over the 5-inch scoop span. However, this gradient has been calculated to have a small effect. In addition, since the new method uses three RTDs for each hot leg temperature measurement, it is a statistically more accurate temperature measurement than the former method which used only one RTD for each hot leg temperature measurement.

Regarding the uncertainties associated with RCS flow for Diablo Canyon with the RTD bypass elimination and Eagle 21 equipment, the licencee stated (Ref. 3) that Westinghouse has performed calculations that include the instrument uncertainties associated with the precision flow calorimetric. These uncertainties include those for steam line pressure, pressurizer pressure, Thot and Tcold and the use of the Eagle 21 Man-Machine Interface to read these parameters. With the use of the RCS flow calorimetric to normalize the cold leg elbow tap measurement, the flow measurement uncertainty, including the elbow tap, has been found to be plus or minus 2.1%, for indicated flow. The total flow measurement uncertainty (FMU), including the required feedwater fouling allowance of 0.1%, is 2.2% . The licensee plans to use the current Diablo Canyon TS RCS FMU of 2.4% which is conservative with respect to that of the calculated FMU for Diablo Canyon of 2.2% (including the 0.1% feedwater fouling factor) with the RTD bypass elimination and Eagle 21 equipment. We therefore find this to be accepatabe.

Regarding the effect of the increased streaming from low leakage loading on the hot leg Tave value, the licensee reports that data taken at Diablo Canyon before and after introduction of low leakage loading patterns shows approximately a 2% drop in RCS flow taken via RCS flow calorimetric, with no drop in flow taken via the elbow taps. Thus, the hot leg streaming bias resulting from the low leakage loading pattern results in a measured hot leg Tave higher than the true hot leg Tavg. Therefore, the bias due to low leakage loading is conservative with respect to the safety analyses. PG&E presented the RCS flow measurement values (Ref. 3) for Diablo Canyon Units 1 and 2 taken at the beginning of cycle 6. These were about 2% over the TS limits for Unit 1 and about 1% over the TS limits for Unit 2.

Based on data taken at plants similar to Diablo Canyon, it has been assumed for the purpose of the uncertainty analysis that Diablo Canyon will experience cold leg streaming. Based on cold leg streaming data, the RTD bypass elimination implementation has been designed to ensure conservative RCS calorimeteric flow measurement. Also, a 1 °F Tavg penalty has been included in the Protection System Setpoint Study for conservatism in the safety analysis to account for cold leg streaming.

The licensee uses the Westinghouse recommended RTD cross-calibration method to calibrate the RTDs at each refueling prior to startup. For small deviations found by their in-situ cross calibration method, the calibration of the affected RTD(s) will be compensated in the electronics by use of polynomial curves to account for the RTD shift. The platinum resistance temperature detectors (RTDs) are believed to be very stable and to have relatively small calibration drifts. However, according to several sources (Refs. 6, 7) RTDs have been known to shift in calibration which could possibly be in one direction. Therefore, PG&E will periodically compare the average temperature of the RTDs to the saturation temperature for the coresponding steam generator pressure to ensure that there is not a common drift of the RTDs in one direction.

To ascertain that the new method of recording the hot leg temperature is reasonably accurate in comparison to the old way of measuring hot leg temperature, PG&E will check some parameters during startup and power ascension testing (i.e., RCS loop delta-T and reactor power) to ensure that these indicators correlate to actual plant conditions based on the results of previous power ascenion testing. These will be evaluated and any unexpected deviation or anomaly will be investigated and addressed.

4.1.6 RTD Failure Detection

The RTD input signals are processed by the Eagle 21 Temperature Averaging System (TAS). The two cold leg temperatures are processed to produce an average cold leg temperature T-cold and the three hot leg temperatures are processed to produce the average hot leg temperature T-have. T-have is then combined with T-cold to produce the loop average temperature (T-avg) and the loop difference temperature (Delta-T).

The two cold leg temperature input signals are subjected to range and consistency checks and then averaged to provide a group value for T-cold. If these signals agree within an acceptable interval (DELTAC), the group-quality is set to GOOD. The DELTAC value is initially set to 2 °F based on engineering judgement. If the signals do not agree within the acceptable tolerance DELTAC, the group quality is set to BAD and the individual input signal qualities are set to POOR.

The Eagle 21 TAS employs an algorithm that automatically detects a defective hot leg RTD input signal and eliminates that input from the T-have calculation. This is accomplished by incorporating a Redundant Sensor Algorithm (RSA) into the hot leg temperature signal processing. The RSA determines the validity of each input signal and automatically rejects a defective input. Also, each of the three hot leg temperature input signals is subjected to a range check. These signals are utilized to calculate an estimated average hot leg temperature which is then consistency checked against the other two estimates for average hot leg temperature. The average of the three estimated average hot leg temperatures is computed and the individual estimates are checked to determine if they agree within plus or minus DELTA of the average value. The DELTA value will initally be set to 8 °F at startup to avoid spurious RTD trouble alarms. At 100% power, DELTA is to be set to a value of 1 °F outside of the observed deviation from the estimate of Thot average. The group value T-have is set to the average of the three estimated average hot leg temperatures.

Two control room annunciators, "PPS Trouble" and "PPS RTD Failure", are provided to inform the operator of an RTD malfunction. The "PPS Trouble" annunciator indicates that the Eagle 21 process protection system has determined that the Tavg group value for a coolant loop is set to POOR and that there are therefore only two good narrow range Thot signals for the loop in question. The "PPS RTD Failure" annunciator indicates that the Eagle 21 process protection system has detected a cold leg or hot leg RTD failure. Also, a failed RTD can be detected from a channel check which is performed every twelve hours. On failure of an RTD, the channel would be tripped and the technical specification action statement would go into effect. The second element of each RTD is a spare and its leads can be switched from the failed RTD leads in the cable spreading room which is located outside of containment, one floor below the control room.

4.1.7 Non-LOCA Accidents

As stated in Section 3.1.4, with the removal of the RTD bypass system the new RTD response time is increased in the new system from 6.0 seconds to 7.0 seconds to provide for margin. Currently, the overall response time of the RTD bypass system assumed in the safety analysis is 6.0 seconds. Therefore, the analyses of transients affected by the increased RTD total response time (those that depend on the OTDT and OPDT trips) were examined by the licensee. These transients are: (1) RCCA Bank Withdrawal at Power, (2) Loss of External Electrical Load and/or Turbine Trip, (3) Steam Line Break Core Response at Power, and (4) Steam Line Break Mass/Energy Releases for Outside Containment for Equipment Qualification. These transients are discussed below.

(1) Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power

The Uncontrolled RCCA Bank Withdrawal at Power event is described in FSAR Update Section 15.2.2. This event was reanalyzed assuming the increased OTDT time response. All other assumptions and methods used were consistent with the FSAR Update analysis. The results showed that the safety analyses DNBR limit is met. Therefore, we find this to be acceptable.

(2) Loss of External Electrical Load and/or Turbine Trip

The Loss of External Electrical Load and/or Turbine Trip event is described in FSAR Update Section 15.2.7. This transient is analyzed to demonstrate that the pressurizer and steam generator safety valves are adequately sized to prevent overpressuriztion of the RCS and steam generators, respectively. Also, the analysis ensures that the RCS heatup does not result in DNB in the core. This case was reanalyzed assuming the increased OTDT time response. Of the four cases analyzed in the FSAR Update only the BOL with pressure control case tripped on OTDT. This case was reanalyzed assuming the increased OTDT time response. All other assumptions and methods used were consistent with the FSAR Update analysis. For the other cases, the previous analysis documented in the FSAR Update remains applicable. The DNBR did not fall below the safety analysis limit value. By delaying the OTDT trip, this case now results in a reactor trip from High Pressurizer Pressure. Therefore, we find this to be acceptable.

(3) Steam Line Break Core Response at Power

Steam line break from an at power condition is not explicitly analyzed in the Diablo Canyon FSAR Update. The analysis presented in Section 15.4.2.1 of the FSAR Update demonstrates that the core is protected in the event of a steam line break from a hot zero power condition with the reactor tripped and the most reactive RCCA stuck out of the core. For breaks occurring when the reactor is a power, the FSAR analysis demonstrates that the DNB design basis is met for the post-trip time frame. The full power steam line break analysis cases documented in Reference 3 were reanalyzed to examine the effects of the increased OPDT reactor trip response time. The limiting case, in terms of DNBR, occurs for a steam line break of 1.4 square feet and results in a reactor trip on Low Steam Line Pressure SI. The DNBR remains above the safety analysis limit value. Therefore, we find this to be acceptable.

(4) Steam Line Break Mass/Energy Release Outside Containment

Steam line break mass and energy released for use in outside containment Equipment Qualification (EQ) evaluation were calculated for Diablo Canyon as documented in Reference 8. This reanalysis was consistent with the FSAR Update analysis and used the LOFTRAN code. For the cases that trip on OPDT, the reactor trip occurs early in the transient, before the tube bundle is uncovered and superheated steam releases occur. The small delay in the time of reactor trip, on the order of one second, has only a slight effect on the calculated mass and energy release data for these cases as expected. Therefore, we find the calculation of mass and energy released to be acceptable.

4.1.8 LOCA and Safety Analyses

The licensee stated (References 1 and 2) that in their evaluations there were no effects from the RTD bypass modification that impacted either the large break or small break LOCA events. Their evaluations also included post-LOCA long-term cooling subcriticality, hot leg switchover to prevent boron precipitation, and the post-LOCA long-term core cooling minimum flow requirement. Each of the above accidents was evaluated and in each case it was shown that these modifications did not result in any design or regulatory limit being exceeded. We therefore find this to be acceptable.

4.2 Trip Time Delay

The Trip Time Delay (TTD) functional upgrade was incorporated as part of the Eagle 21 process protection system Steam Generator Level Low-Low reactor trip. The TTD is a means to reduce the frequency of unnecessary feedwater related reactor trips. The TTD function is designed for low power or startup operations and results in a delay in actuation of a Steam Generator Water Level - Low-Low reactor trip when the power level is less than 50% RTP. Once the low-low level trip setpoint is reached, the TTD acts to delay reactor trip and auxiliary feedwater sytem actuation to allow time for operator corrective action or for natural stabilization of shrink/swell water level transients. There are pre-determined programmed trip delaly times that are based upon (1) the prevailing power level at the time a low-low level trip setpoint is reached, and (2) the number of steam generators that are affected.

The implementation of the TTD function at DCPP differs in several ways from that of the conceptual design documented in WCAP-11325-P-A that received generic approval. These differences were mostly related to the implementation of the Eagle 21 digital process protection system instead of the former Solid

State Protection System (SSPS). The TTD circuitry is armed whenever reactor power is less than 50 percent. We find this to be acceptable.

4.2.1 Analysis

The licensee used the approved analysis methodology of WCAP-11325-P-A to perform DCPP-specific Loss of Normal Feedwater analyses to provide the safety analysis limits for 1-of-4 and 2-of-4 logic time delay curves at power levels up to 50 percent power. The analyses were used to establish Safety Analysis Limits for the Steam Generator Water Level Low-Low signal delay times and trip setpoints. For all the cases, the auxiliary feedwater heat removal capability was sufficient to remove the decay heat such that the pressurizer does not fill. This ensured that all applicable Condition II safety analysis acceptance criteria are met. Therefore we find this to be acceptable.

A number of other events that credit the Steam Generator Water Level Low-Low trip were evaluated to ensure that with the time delays calculated above, the current licensing basis events presented in the FSAR Update remain as the limiting transients. The transients evaluated were: Full Power Loss of Normal Feedwater (FSAR Update 15.2.8), Loss of Offsite Power to the Station Auxiliaries (FSAR Update 15.2.9), Major Rupture of Main Feedwater Pipe (FSAR Update 15.4.2.2), and Steam Line Break Mass/Energy Releases Outside of Containment. It was found that implementation of the TTD in the DCPP units introduces no time delays at indicated power levels greater than 50 percent. Therefore it is concluded that implementation of the TTD does not invalidate the cases in the design basis documentation.

The DCPP Units have ATWS Mitigation System Actuation Circuitry (AMSAC) which is armed whenever reactor power is above 40 percent. Since the TTD circuitry is armed whenever reactor power is less that 50 percent, it possible that both TTD and AMSAC will actuate in the overlapping range of conditions. Since the DCPP is equipped with the P-9 permissive, which blocks reactor trip on turbine trip when below the permissive setpoint, which could be as high as 50 percent, a reactor trip from an AMSAC-initiated turbine trip might not occur in the 40 to 50 percent power range. However, the analysis is not affected by the AMSAC-initiated turbine trip since, at the 40 to 50 percent power levels, there is adequate steam relief capability via the steam generator safety valves, steam generator PORVs, and steam dumps to accommodate the load rejection. Therefore we find this to be acceptable.

4.3 <u>New Steam Line Break Protection Logic</u>

The current configuration of the DCPP RPS includes SI and steam line isolation actuation known as old SLB protection. With the upgrade to the Eagle 21 digital electronics, the protection system is to be upgraded to the more recent standard Westinghouse SI and steam line isolation actuation logic known as new SLB protection.

The new SLB protection actuation of SI will result from Low Steam Line Pressure, or Low Pressurizer Pressure, or High Containment Pressure. Steam Line Isolation will result from High-High Containment Pressure, or Negative Steam Line Pressure Rate High, or Low Steam Line Pressure.

4.3.1 Analysis

The licensee re-evaluated the safety analyses for transients affected by the impact of the new SLB protection implementation. These transients included Steam Line Break Core Response (FSAR Update 15.4.2.1), Steam Line Break Mass And Energy Releases for Containment Response (documented in WCAP-11938, Volumes 1 and 2), Steam Line Break for Outside Containment EQ evaluation (documented in PG&E Letter DCL-89-132, to NRC, dated May 15, 1989), and Feedline Break (FSAR Update 15.4.2.2). From the results of the safety evaluation for the new SLB protection logic, it was found that there was no impact on the current safety analyses. Therefore we find this to be acceptable.

4.4 Steam Generator Water Level High-High Turbine Trip Setpoint

The safety function of the Steam Generator High-High Level Trip is to protect the core from the consequences of a loss of feedwater control accident. The Steam Generator High-High Level Turbine Trip setpoint was increased to reduce the likelihood of spurious trips due to normal operating transients. This change was within the range of the Eagle 21 RPS and therefore no specific hardware modifications were required. We find this to be acceptable.

4.4.1 Analysis

An evaluation of the impact of increasing the Steam Generator High-High Water Level trip setpoint was performed. The current setpoint value is 67 percent narrow range span (NRS). Westinghouse engineering evaluations determined that 82 percent NRS is the highest trip setpoint (excluding instrument errors) that is acceptable for the Model 51 steam generators. When instrument uncertainty is included, the nominal high level trip setpoint is required to be less than or equal to 75 percent NRS. Therefore the licensee's request to raise the setpoint from 67 percent to 75 percent NRS is acceptable.

5.0 EVALUATION OF TECHNICAL SPECIFICATIONS

The Technical Specifications were changed as a result of the upgrade to the Eagle 21 system Process Protection System, the removal of the RTD bypass system and other enhancements.

1. The following Technical Specification changes for Overtemperature Delta-T and Overpower Delta-T that were affected by the RTD bypass system removal:

   Bases Page B 2-5 - Overpower Delta-T

   There was a clarification regarding reponse time due the RTD bypass removal. Also, there was an explanation regarding the Delta-T measurements.

   Bases Page B 2-6 - Overtemperature Delta-T

There was a clarification regarding response time due the RTD bypass removal. Also, there was an explanation regarding the loop Delta-T measurements.

TABLE 2.2-1 - Reactor Trip System Instrumentation Trip Setpoints

Functional Unit 7, Overtemperature Delta-T, Note 1 was changed due to the implementation of Eagle 21 and the RTD bypass system removal. Functional Unit 8, Overpower Delta-T, Notes 3 and 4 were changed due to implementation of Eagle 21 and the RTD bypass system removal.

TABLE 3.3-2 - Reactor Trip System Instrumentation Response Times

The response times were changed to equal or greater than 7 seconds based on accident analysis and footnote 2 explained that the response time includes 4 seconds for the RTDs mounted in thermowells. This applies to: Functional Unit 7, Overtemperature Delta-T and Functional Unit 8, Overpower Delta-T.

TABLE 4.3-1 - Reactor Trip System Instrumentation Surveillance Requirements

The note 11 indicating that channel calibration shall include the RTD bypass loops flow rate was removed for Functional Unit 7, Overtemperature Delta-T as it does not pertain after the RTD bypass loops are removed.

The above changes are acceptable as they are in accordance with the condition for RTD bypass system removal as found acceptable in the Section 3.1 above.

2. The following Low-Low Steam Generator Water Level entries in the Technical Specifications reflect incorporation of the Trip Time Delay (TTD) feature.

Bases Page B 2-7 - Steam Generator Water Level

There was text added regarding implementation of the TTD feature.

TABLE 2.2-1 - Reactor Trip System Instrumentation Trip Setpoints

Functional Unit 13, Steam Generator Water Level-Low-Low, was revised to reflect incorporation of the Trip Time Delay (TTD) feature. This included entries for trip setpoint and allowable values for: RCS Loop delta-T Equivalent to Power (1) equal or less than 50% RTP, with variable time delay, and (2) greater than 50% RTP, with no time delay. This allows for variable delays, the magnitude of the delays decreases with increasing primary side power level up to 50% RTP.

TABLE 3.3-1 - Reactor Trip System Instrumentation

Functional Unit 13, Steam Generator Water Level-Low-Low, was revised to reflect incorporation of the TTD feature. This required the addition of the RCS Delta-T instrumentation needed for the TTD feature.

TABLE 3.3-2 - Reactor Trip System Instrumentation Response Times

Functional Unit 13, Steam Generator Water Level-Low-Low, was revised with footnote 3 to indicate that the response time listed of equal or less than 2.0 seconds does not include Trip Time Delays. Response times include the transmitters, Eagle-21 PPS cabinets, Solid State Protection cabinets and actuation devices only. This reflects the response times necessary for Thermal Power in excess of 50% RTP.

TABLE 4.3-1 - Reactor Trip System Instrumentation Surveillance Requirements

Functional Unit 13, Steam Generator Water Level-Low-Low, was revised with a row added for RCS Loop Delta-T requirements.

TABLE 3.3-3 - Engineered Safety Features Actuation System Instrumentation

For Functional Unit 6, Auxiliary Feedwater, item c, Steam Generator Water Level-Low-Low, item 1)b and item 2)b were added to include requirements for RCS Loop Delta-T for the Start of Motor-Driven and Turbine-Driven Pumps.

TABLE 3.3-4 - Engineered Safety Features Actuation System Instrumentation Trip Setpoints

For Functional Unit 6, Auxialiary Feedwater, item c, Steam Generator Water Level-Low-Low, requirements were added for RCS Loop Delta-T for 1) power equal or less than 50% RTP and 2) power greater than 50% RTP. Included was a Note 2 related to TTD.

TABLE 3.3-5 - Engineered Safety Features Response Times

Functional Unit 9, Steam Generator Water Level-Low-Low, was revised to add a footnote to the response time for the Motor-Driven and Turbine-Driven Auxiliary Feedwater Pumps which state "Does not include Trip Time Delays. Response times include the transmitters, Eagle-21 Process Protection cabinets, Solid State Protection System cabinets and actuation devices only." This reflects the response times necessary for Thermal Power in excess of 50% power.

TABLE 4.3-2 - Engineered Safety Features Actuation System Instrumentation
Surveillance Requirements

Functional Unit 6c, Steam Generator Water Level-Low-Low, was revised to include requirements for RCS Loop Delta-T.

The above changes are acceptable as they are in accordance with the incorporation of the trip time delay (TTD) feature as found acceptable in the Section 3.2 above.

3. The following Technical Specification changes reflect incorporation of a new Steam Line Break (SLB) protection logic.

This new logic results in deletion of the Safety Injection (SI) and Steam Line Isolation on High Steam Line Flow coincident with P-12 Low-Low Tavg and High Steam Line Flow coincident with Low Steam Line Pressure. SI on High Differential Pressure Between Steam Lines is also deleted. SI and Steam Line Isolation on Low Steam Line Pressure and Steam Line Isolation on High Negative Steam Line Pressure Rate coincident with P-11 Pressurizer Pressure is added as part of Eagle 21 upgrade in place of the deleted functions.

TABLE 3.3-3 - Engineered Safety Features Actuation System Instrumentation

For Functional Unit 1, Safety Injection, item 1e, Differential Pressure Between Steam Lines-High, was eliminated. Item 1f, Steam Flow in Two Steam Lines-High and coincident with either Tavg-Low-Low or Steam Line Pressure-Low, was eliminated except for the part on Steam Line Pressure-Low which was modified. For Functional Unit 4, Steam Line Isolation, item 4d, Steam Flow in Two Steam Lines-High and Coincident with Either Tavg-Low-Low or Steam Line Pressure-Low, was eliminated except for the part on Steam Line Pressure-Low, which was modified. Item 4e, Negative Steam Line Pressure Rate-High was added. Functional Unit 8, Engineered Safety Features Actuation System Interlocks, item b, Low-Low Tavg, P-12 was deleted as it is not used in the new SLB logic.

TABLE 3.3-3 NOTATIONS

The original ## notation using P-12 (Low-Low Tavg) is deleted and replaced by "Trip function automatically blocked above P-11 (Pressurizer Pressure Interlock) setpoint and may be manually blocked below P-11 when Safety Injection on Steam Line Pressure-Low is not blocked."

TABLE 3.3-4 - Engineered Safety Features Actuation System Instrumentation Trip Setpoints

For Functional Unit 1, Safety Injection, item 1e, Differential Pressure Between Steam Lines-High, was eliminated. Item 1f, Steam Flow in Two Steam Lines-High and coincident with either Tavg-Low-Low or Steam Line Pressure-Low, was eliminated except for the part on Steam Line Pressure-Low which was modified. For Functional Unit 4, Steam Line Isolation, item 4d, Steam Flow in Two Steam Lines-High and coincident with either Tavg-Low-Low or Steam Line Pressure-Low, was eliminated except for the part on Steam Line Pressure-Low, which was modified. Item 4e, Negative Steam Line Pressure Rate-High was added. Note 1 was added for time constants utilized in the lead/lag function added as part of the new SLB logic for Functional Units 1 and 4. For Functional Unit 8, Engineered

Safety Features Actuation system Interlocks, item b, Low-Low Tavg P-12 was deleted as it is not used in the new SLB logic.

TABLE 3.3-5 - Engineered Safety Features Response Times

The Initiating Signal and Function 4, "Differential Pressure Between Steam Lines-High", was deleted and replaced by "Negative Steam Line Pressure Rate-High". The Item 4a, "Safety Injection (ECCS)" together with its listing of 8 items was eliminated and replaced by Steam Line Isolation for which the Response Time was given as equal or less than 8 seconds.

The Initiating Signal and Function 5, "Steam Flow in Two Steam Lines - High coincident with Tavg-Low-Low was deleted.

The title for Initiating Signal and Function 6, "Steam Flow in Two Steam Lines-High Coincident with Steam Line Pressure-Low" was changed to "Steam Line Pressure-Low."

TABLE 4.3-2 - Engineered Safety Features Actuation System Instrumentation Surveillance Requirements

For Functional Unit 1, Safety Injection, item 1e, Differential Pressure Between Steam Lines-High, was eliminated. Item 1f, Steam Flow in Two Steam Lines-High and coincident with either Tavg-Low-Low or Steam Line Pressure-Low, was eliminated except for the part on Steam Line Pressure-Low. For Functional Unit 4, Steam Line Isolation, item 4d, Steam Flow in Two Steam Lines-High and coincident with either Tavg-Low-Low or Steam Line Pressure-Low, was eliminated except for the part on Steam Line Pressure-Low. Item 4e, Negative Steam Line Pressure Rate-High was added with a footnote 3 to reflect that the trip function is automatically blocked above P-11 (Pressurizer Pressure Interlock) setpoint and may be manually blocked below P-11 when Safety Injection on Steam Line Pressure-Low is not blocked.

The above changes are acceptable as they are in accordance with the incorporation of the new Steam Line Break protection logic as found acceptable in the Section 3.2 above.

4. The following Technical Specification changes reflect incorporation of a Steam Generator Water Level High-High Turbine trip setpoint.

TABLE 3.3-4 - Engineered Safety Features Actuation System Instrumentation Trip Setpoints

Functional Unit 5, Turbine Trip and Feedwater Isolation, was modified to change the trip setpoint and allowable value for 5b, Steam Generator Water Level-High-High. The trip set point was changed from less than or equal to 67% to less than or equal to 75% of the narrow range instrument span each steam generator. The allowable value was changed from less than or equal to 68% to less than or equal to 75.5% of narrow range instrument span for each steam generator.

These changes to protect the core from the consequences of a loss of feedwater control accident were reviewed in Section 3.4 above and were found to be acceptable.

6.0 CONCLUSION

The impact of implementing the Eagle 21 process protection system, removal of the RTD bypass system, trip time delay feature, new steam line break logic, and increased steam generator water level High-High turbine trip setpoint, have been reviewed by the staff. Based on the above, the staff concludes that the design of the Eagle 21 RPS system meets the criteria of R.G. 1.152, and demonstrates appropriate defense-in-depth. The staff further concludes that the AMSAC/Eagle 21 systems provide adequate diversity and thereby satisfy the requirements of 10 CFR 50.62 for ATWS mitigation. The staff also concludes that the proposed RTD bypass manifold elimination and replacement RTDs provide acceptable primary coolant temperature monitoring capability. The staff, therefore, finds the Eagle 21 RPS retrofit and RTD bypass modification, and associated TS changes to be acceptable.

7.0 STATE CONSULTATION

In accordance with the Commission's regulations, the California State official was notified of the proposed issuance of the amendments. The State official had no comments.

8.0 ENVIRONMENTAL CONSIDERATION

These amendments change a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendments involve no significant hazards consideration, and there has been no public comment on such finding (57 FR 53786). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

9.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributors: C. Doutt
H. Balukjian

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