ATTACHMENT B

MARKED-UP TECHNICAL SPECIFICATIONS

("Item" designations are consistent with Attachment D evaluations)

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TABLE 1.1

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days
Q	At least once per 92 days.
SA	At least once per 184 days.
R	At least once per 18 months.
S/U	Prior to each reactor startup.
P	Completed prior to each release.
N.A.	Not applicable.
R24, REFUELING INTERVAL	At least once per 24 months.

Item 1

3.0.5 This specification delineates the applicability of each specification to Unit 1 and Unit 2 operation.

4.0.1 This specification establishes the requirement that surveillances must be performed during the OPERATIONAL MODES or other conditions for which the requirements of the Limiting Conditions for Operation apply unless otherwise stated in an individual Surveillance Requirement. The purpose of this specification is to ensure that surveillances are performed to verify the operational status of systems and components and that parameters are within specified limits to ensure safe operation of the facility when the plant is in a MODE or other specified condition for which the associated Limiting Conditions for Operation are applicable. Surveillance Requirements do not have to be performed when the facility is in an OPERATIONAL MODE for which the requirements of the associated Limiting Condition for Operation do not apply unless otherwise specified. The Surveillance Requirements associated with a Special Test Exception are only applicable when the Special Test is used as an allowable exception to the requirements of a specification.

Item 2

4.0.2 Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. ~~It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages.~~ The limitation of Specification 4.0.2 is based on engineering judgement and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

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4.0.3 This specification establishes the failure to perform a Surveillance Requirement within the allowed surveillance interval, defined by the provisions of Specification 4.0.2, as a condition that constitutes a failure to meet the OPERABILITY requirements for a Limiting Condition for Operation. Under the provisions of this specification, systems and components are assumed to be OPERABLE when Surveillance Requirements have been satisfactorily performed within the specified time interval. However, nothing in this provision is to be construed as implying that systems or components are OPERABLE when they are found or known to be inoperable although still meeting the Surveillance Requirements. This specification also clarifies that the ACTION requirements are applicable when Surveillance Requirements have not been completed within the allowed surveillance interval and that the time limits of the ACTION requirements apply from the point in time it is identified that a surveillance has not been performed and not at the time that the allowed

Insert A
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It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are specified to be performed at least once each REFUELING INTERVAL. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed once each REFUELING INTERVAL. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation.

POSITION INDICATION SYSTEM - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.3.3 One digital rod position indicator (excluding demand position indication) shall be OPERABLE and capable of determining the control rod position within ± 12 steps for each shutdown or control rod not fully inserted.

APPLICABILITY: MODES 3*#, 4*# and 5*#.

ACTION:

With less than the above required position indicator(s) OPERABLE, immediately open the Reactor Trip System breakers.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each of the above required digital rod position indicator(s) shall be determined to be OPERABLE by verifying that the digital rod position indicators agree with the demand position indicators within 12 steps when exercised over the full range of rod travel at least once ~~per 18 months.~~ each REFUELING INTERVAL.

Item 3

*With the Reactor Trip System breakers in the closed position.

#See Special Test Exceptions Specification 3.10.4

ROD DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full-length shutdown and control rod drop time from the fully withdrawn position shall be less than or equal to 2.7 seconds from beginning of decay of stationary gripper coil voltage to dashpot entry with:

a. T_{avg} greater than or equal to 541°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

With the drop time of any full-length rod determined to exceed the above limit, restore the rod drop time to within the above limit prior to proceeding to MODE 1 or 2.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The rod drop time of full-length rods shall be demonstrated through measurement prior to reactor criticality:

a. For all rods following each removal of the reactor vessel head,

b. For specifically affected individual rods following any maintenance on or modification to the Control Rod Drive System which could affect the drop time of those specific rods, and

c. At least once ~~per 18 months.~~ each REFUELING INTERVAL. Item 4

TABLE 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) R24	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux						Item 5
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 (Continued)

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~~ R24	N.A	1, 2 Item 6
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	N.A.	~~R~~ R24	N.A.	1 Item 7
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 4.3-2 (Continued)

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) R24	N.A.	1,2,3*,4*,5* Item 8

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)								Item 9
a. Manual Initiation	N.A.	N.A.	N.A.	~~R~~ R24	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(4)	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, 4**

* These changes from License Amendments 84 & 83.

** These changes from License Amendments 89 & 88.

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

NCTIONAL 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
Containment Isolation								
a. Phase "A" Isolation								Item 10
1) Manual	N.A.	N.A.	N.A.	~~R~~ R24	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(4)	1, 2, 3, 4
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
b. Phase "B" Isolation								Item 11
1) Manual	N.A.	N.A.	N.A.	~~R~~ R24	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, 4
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) Deleted								
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4 |

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
1. Steam Line Isolation								Item 12
a. Manual	N.A.	N.A.	N.A.	~~R~~ R24	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(5)
2) RCS Loop ΔT	N.A.	R	Q	N.A	N.A	N.A	N.A	1, 2

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
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							Item 13	
c. Reactor Trip, P-4	N.A.	N.A.	N.A.	~~R~~ R24	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 Containment Ventilation Exhaust Radiation - 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.
(4) Except relays K612A, K614B, K615A, and K615B, which shall be tested, at a minimum, once per 18 months during refueling and during each Cold Shutdown unless they have been tested within the previous 92 days.
(5) For Mode 3, the Trip Time Delay associated with the Steam Generator Water Level-Low-Low channel must be less than or equal to 464.1 seconds.

3/4.4.3 PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.3 The pressurizer shall be OPERABLE with a water volume of less than or equal to 1600 cubic feet and two groups of pressurizer heaters each having a capacity of at least 150 kW.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one group of pressurizer heaters inoperable, restore at least two groups to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the Reactor trip breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The pressurizer water volume shall be determined to be within its limit at least once per 12 hours.

4.4.3.2 The capacity of each of the above required groups of pressurizer heaters shall be verified by measuring heater group power at least once per 92 days.

4.4.3.3 The emergency power supply for the pressurizer heaters shall be demonstrated OPERABLE at least once ~~per 18 months~~ by transferring power from the normal to the emergency power supply each REFUELING INTERVAL and energizing the heaters.

Item 14

4.4.6.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere particulate or gaseous radioactivity monitor at least once per 12 hours;

b. Monitoring the containment structure sump inventory and discharge at least once per 12 hours;

c. Measurement of the CONTROLLED LEAKAGE to the reactor coolant pump seals at least once per 31 days when the Reactor Coolant System pressure is 2235 ± 20 psig with the modulating valve fully open. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4;

d. Performance of a Reactor Coolant System water inventory balance at least once per 72 hours, except when T_{avg} is being changed by greater than 5°F/hour or when diverting reactor coolant to the liquid holdup tank, in which cases the required inventory balance shall be performed within 12 hours after completion of the excepted operation; and

e. Monitoring the Reactor Head Flange Leakoff System at least once per 24 hours.

4.4.6.2.2 As specified in Table 3.4-1, Reactor Coolant System pressure isolation valves shall be demonstrated OPERABLE pursuant to Specification 4.0.5, except that in lieu of any leakage testing required by Specification 4.0.5, each valve shall be demonstrated OPERABLE by verifying leakage to be within its limit:

a. At least once each REFUELING INTERVAL ~~Every refueling outage~~ during startup, Item 15

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve, and

c. Within 24 hours following valve actuation due to automatic or manual action or flow through the valve. After each disturbance of the valve, in lieu of measuring leak rate, leak-tight integrity may be verified by absence of pressure buildup in the test line downstream of the valve.

The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4.

c. By a visual inspection which verifies that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions. This visual inspection shall be performed:

1) For all accessible areas of the containment prior to establishing CONTAINMENT INTEGRITY, and

2) At least once daily of the areas affected within containment by containment entry and during the final entry when CONTAINMENT INTEGRITY is established.

d. At least once each REFUELING INTERVAL ~~per 18 months~~ by a visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion; Item 16

e. At least once each REFUELING INTERVAL ~~per 18 months~~ by: Items 17, 18

1) Verifying that each automatic valve in the flow path actuates to its correct position on a Safety Injection actuation test signal.

2) Verifying that each of the following pumps start automatically upon receipt of a Safety Injection actuation test signal:

a) Centrifugal charging pump,

b) Safety Injection pump, and

c) Residual Heat Removal pump.

f. By verifying that each of the following pumps develops the indicated differential pressure on recirculation flow when tested pursuant to Specification 4.0.5:

1) Centrifugal charging pump $\geq$ 2400 psid,

2) Safety Injection pump $\geq$ 1455 psid, and

3) Residual Heat Removal pump $\geq$ 165 psid.

g. By verifying the correct position of each electrical and/or mechanical position stop for the following ECCS throttle valves:

1) Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE, and

2) At least once each REFUELING INTERVAL. ~~per 18 months~~.

Item 19

Charging Injection Throttle Valves	Safety Injection Throttle Valves
8810A	8822A
8810B	8822B
8810C	8822C
8810D	8822D

h. By performing a flow balance test, during shutdown, following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics and verifying that:

1) For centrifugal charging pumps, with a single pump running:

a) The sum of injection line flow rates, excluding the highest flow rate, is greater than or equal to 299 gpm, and

CONTAINMENT VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.7 One purge supply line and/or one purge exhaust line of the Containment Purge System may be open or the vacuum/pressure relief line may be open. The vacuum/pressure relief line may be open provided the vacuum/pressure relief isolation valves are blocked to prevent opening beyond 50° (90° is fully open). Operation with any two of these three lines open is permitted. Operation with the purge supply and/or exhaust isolation valves open or with the vacuum/pressure relief isolation valves open up to 50° shall be limited to less than or equal to 200 hours during a calendar year.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With a containment purge supply and/or exhaust isolation valve open or the vacuum/pressure relief isolation valves open up to 50° for more than 200 hours during a calendar year or the Containment Purge System open and the vacuum/pressure relief lines open, or with the vacuum/pressure relief isolation valves open beyond 50°, close the open isolation valve(s) or isolate the penetration(s) within 1 hour; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7.1 The position of the containment purge supply and exhaust isolation valves and the vacuum/pressure relief isolation valves shall be determined closed at least once per 31 days.

4.6.1.7.2 The cumulative time that the purge supply and/or exhaust isolation valves or the vacuum/pressure relief isolation valves have been open during a calendar year shall be determined at least once per 7 days.

4.6.1.7.3 The vacuum/pressure relief isolation valves shall be verified to be blocked to prevent opening beyond 50° at least once ~~per 18 months~~ each REFUELING INTERVAL.

Item 20

SPRAY ADDITIVE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.2 The Spray Additive System shall be OPERABLE with:

a. A spray additive tank with a contained volume of between 2025 and 4000 gallons of between 30 and 32% by weight NaOH solution, and

b. Two spray additive eductors each capable of adding NaOH solution from the chemical additive tank to a Containment Spray System pump flow.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the Spray Additive System inoperable, restore the system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours; restore the Spray Additive System to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The Spray Additive System shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position;

b. At least once per 6 months by:

1) Verifying the contained solution volume in the tank, and

2) Verifying the concentration of the NaOH solution by chemical analysis.

c. At least once ~~per 18 months~~ each REFUELING INTERVAL by verifying that each automatic valve in the flow path actuates to its correct position on a Containment Spray actuation test signal; and (Item 21)

d. At least once per 5 years by verifying both spray additive and RWST full flow from the test valve 8993 in the Spray Additive System.

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying a cooling water flow rate of greater than or equal to 1650* gpm to each cooler, and

3) Verifying that each containment fan cooler unit starts on low speed.

b. At least once ~~per 18 months~~ each REFUELING INTERVAL by verifying that each containment fan cooler unit starts automatically on a Safety Injection test signal. Item 22

* The CFCU cooling water flow rate requirement of TS 4.6.2.3a.2) may not be met during Section XI testing and in Mode 4 during residual heat removal heat exchanger operation.

3/4.6.3 CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 Each containment isolation valve shall be OPERABLE.*

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With one or more of the isolation valve(s) inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and:

a. Restore the inoperable valve(s) to OPERABLE status within 4 hours, or

b. Isolate each affected penetration within 4 hours by use of at least one deactivated automatic valve secured in the isolation position, or

c. Isolate each affected penetration within 4 hours by use of at least one closed manual valve or blind flange; or

d. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

*Locked or sealed closed valves may be opened on an intermittent basis under administrative control.

SURVEILLANCE REQUIREMENTS

4.6.3.1 Each containment isolation valve shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by performance of a cycling test, and verification of isolation time.

4.6.3.2 Each containment isolation valve shall be demonstrated OPERABLE at least once ~~per 18 months~~ each REFUELING INTERVAL by:

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a. Verifying that on a Phase "A" Isolation test signal, each Phase "A" isolation valve actuates to its isolation position;

b. Verifying that on a Phase "B" Isolation test signal, each Phase "B" isolation valve actuates to its isolation position; and

c. Verifying that on a Containment Ventilation Isolation test signal, each containment ventilation isolation valve actuates to its isolation position.

ELECTRIC HYDROGEN RECOMBINERS

LIMITING CONDITION FOR OPERATION

3.6.4.2 Two independent Hydrogen Recombiner Systems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTION:

With one Hydrogen Recombiner System inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT STANDBY within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.6.4.2 Each Hydrogen Recombiner System shall be demonstrated OPERABLE:

a. At least once each REFUELING INTERVAL ~~refueling interval~~ by verifying, during a Recombiner System functional test, that the minimum heater sheath temperature increases to greater than or equal to 700°F within 90 minutes. Upon reaching 700°F, increase the power setting to maximum power for 2 minutes and verify that the power meter reads greater than or equal to 60 kW; and (Item 26)

b. At least once each REFUELING INTERVAL ~~refueling interval~~ by: (Items 27, 28, 29)

1) Performing a CHANNEL CALIBRATION of all recombiner instrumentation and control circuits,

2) Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiner enclosure (i.e., loose wiring or structural connections, deposits of foreign materials, etc.), and

3) Verifying the integrity of all heater electrical circuits by performing a resistance to ground test following the above required functional test. The resistance to ground for any heater phase shall be greater than or equal to 10,000 ohms.

SURVEILLANCE REQUIREMENTS (Continued)

(2) Verifying that each non-automatic valve in the pump flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

(3) Verifying that each non-automatic valve in both steam supplies to the steam turbine-driven pump that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 92 days on a STAGGERED TEST BASIS by: testing the steam turbine-driven pump and motor-driven pumps pursuant to Specification 4.0.5*. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 for the steam turbine-driven pump.

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c. At least once each REFUELING INTERVAL ~~per 18 months~~ by verifying that each auxiliary feedwater pump starts and valve opens* as designed automatically upon receipt of an Auxiliary Feedwater Actuation test signal.

*For the steam turbine-driven pump, when the secondary steam supply pressure is greater than 650 psig.

STEAM GENERATOR 10% ATMOSPHERIC DUMP VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.6 Four steam generator 10% atmospheric dump valves (ADVs) with the associated block valves open and associated remote manual controls, including the backup air bottles, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one less than the required number of 10% ADVs OPERABLE, restore the inoperable steam generator 10% ADV to OPERABLE status within 7 days; or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With two less than the required numbered of 10% ADVs OPERABLE, restore at least one of the inoperable steam generator 10% ADVs to OPERABLE status within 72 hours; or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.6 Each steam generator 10% ADV, associated block valve and associated remote manual controls including the backup air bottles shall be demonstrated OPERABLE:

a. At least once per 24 hours by verifying that the backup air bottle for each steam generator 10% ADV has a pressure greater than or equal to 260 psig, and

b. At least once per 31 days by verifying that the steam generator 10% ADV block valves are open, and

c. At least once ~~per 18 months~~ each REFUELING INTERVAL by verifying that all steam generator 10% ADVs will operate using the remote manual controls and the backup air bottles. (Item 31)

3/4.7.3 VITAL COMPONENT COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3.1 At least two vital component cooling water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With only one vital component cooling water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.3.1 At least two vital component cooling water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position; and

b. At least once each REFUELING INTERVAL ~~per 18 months~~, by verifying that each automatic valve servicing safety-related equipment actuates to its correct position on a Safety Injection or Phase "B" Isolation test signal, as appropriate. Item 32

c. At least once each REFUELING INTERVAL, by verifying that each component cooling water pump starts automatically on an actual or simulated actuation signal. Item 33

3/4.7.4 AUXILIARY SALTWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4.1 At least two auxiliary saltwater trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With only one auxiliary saltwater train OPERABLE, restore at least two trains to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.1 At least two auxiliary saltwater trains shall be demonstrated OPERABLE at ~~lease~~ once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

4.7.4.2 Each auxiliary saltwater pump shall be demonstrated OPERABLE at least once each REFUELING INTERVAL by verifying that each pump starts automatically on an actual or simulated actuation signal.

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ATTACHMENT C

PROPOSED TECHNICAL SPECIFICATION PAGES

Remove Page	Insert Page
1-8	1-8
B 3/4 0-2	B 3/4 0-2
3/4 1-19	3/4 1-19
3/4 1-20	3/4 1-20
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 3-32	3/4 3-32
3/4 3-33	3/4 3-33
3/4 3-34	3/4 3-34
3/4 3-35	3/4 3-35
3/4 4-9	3/4 4-9
3/4 4-20	3/4 4-20
3/4 5-5	3/4 5-5
3/4 5-6	3/4 5-6
3/4 6-10	3/4 6-10
3/4 6-12	3/4 6-12
3/4 6-14	3/4 6-14
3/4 6-15	3/4 6-15
3/4 6-18	3/4 6-18
3/4 7-5	3/4 7-5
3/4 7-9a	3/4 7-9a
3/4 7-11	3/4 7-11
3/4 7-12	3/4 7-12

TABLE 1.1

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours.
D	At least once per 24 hours.
W	At least once per 7 days.
M	At least once per 31 days
Q	At least once per 92 days.
SA	At least once per 184 days.
R	At least once per 18 months.
R24, REFUELING INTERVAL	At least once per 24 months.
S/U	Prior to each reactor startup.
P	Completed prior to each release.
N.A.	Not applicable.

3.0.5 This specification delineates the applicability of each specification to Unit 1 and Unit 2 operation.

4.0.1 This specification establishes the requirement that surveillances must be performed during the OPERATIONAL MODES or other conditions for which the requirements of the Limiting Conditions for Operation apply unless otherwise stated in an individual Surveillance Requirement. The purpose of this specification is to ensure that surveillances are performed to verify the operational status of systems and components and that parameters are within specified limits to ensure safe operation of the facility when the plant is in a MODE or other specified condition for which the associated Limiting Conditions for Operation are applicable. Surveillance Requirements do not have to be performed when the facility is in an OPERATIONAL MODE for which the requirements of the associated Limiting Condition for Operation do not apply unless otherwise specified. The Surveillance Requirements associated with a Special Test Exception are only applicable when the Special Test is used as an allowable exception to the requirements of a specification.

4.0.2 Specification 4.0.2 establishes the limit for which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are specified to be performed at least once each REFUELING INTERVAL. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed once each REFUELING INTERVAL. Likewise, it is not the intent that REFUELING INTERVAL surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Specification 4.0.2 is based on engineering judgement and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

4.0.3 This specification establishes the failure to perform a Surveillance Requirement within the allowed surveillance interval, defined by the provisions of Specification 4.0.2, as a condition that constitutes a failure to meet the OPERABILITY requirements for a Limiting Condition for Operation. Under the provisions of this specification, systems and components are assumed to be OPERABLE when Surveillance Requirements have been satisfactorily performed within the specified time interval. However, nothing in this provision is to be construed as implying that systems or components are OPERABLE when they are found or known to be inoperable although still meeting the Surveillance Requirements. This specification also clarifies that the ACTION requirements are applicable when Surveillance Requirements have not been completed within the allowed surveillance interval and that the time limits of the ACTION requirements apply from the point in time it is identified that a surveillance has not been performed and not at the time that the allowed

POSITION INDICATION SYSTEM - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.3.3 One digital rod position indicator (excluding demand position indication) shall be OPERABLE and capable of determining the control rod position within ± 12 steps for each shutdown or control rod not fully inserted.

APPLICABILITY: MODES 3*#, 4*# and 5*#.

ACTION:

With less than the above required position indicator(s) OPERABLE, immediately open the Reactor Trip System breakers.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each of the above required digital rod position indicator(s) shall be determined to be OPERABLE by verifying that the digital rod position indicators agree with the demand position indicators within 12 steps when exercised over the full range of rod travel at least once each REFUELING INTERVAL.

*With the Reactor Trip System breakers in the closed position.

#See Special Test Exceptions Specification 3.10.4

ROD DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full-length shutdown and control rod drop time from the fully withdrawn position shall be less than or equal to 2.7 seconds from beginning of decay of stationary gripper coil voltage to dashpot entry with:

a. T_{avg} greater than or equal to 541°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

With the drop time of any full-length rod determined to exceed the above limit, restore the rod drop time to within the above limit prior to proceeding to MODE 1 or 2.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The rod drop time of full-length rods shall be demonstrated through measurement prior to reactor criticality:

a. For all rods following each removal of the reactor vessel head,

b. For specifically affected individual rods following any maintenance on or modification to the Control Rod Drive System which could affect the drop time of those specific rods, and

c. At least once each REFUELING INTERVAL.

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.	R24(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 (Continued)

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.	R24	N.A	1, 2
19. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.	N.A.	R24	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 (Continued)

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),R24(16)	N.A.	1,2,3*,4*,5*

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.	R24	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(4)	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, 4**

* These changes from License Amendments 84 & 83.

** These changes from License Amendments 89 & 88.

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
3. Containment Isolation								
a. Phase "A" Isolation								
1) Manual	N.A.	N.A.	N.A.	R24	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(4)	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.	R24	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, 4
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) Deleted								
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
4) Containment Ventilation Exhaust Radiation-High (RM-44A and 44B)	S	R	Q	N.A.	N.A.	N.A.	N.A.	1, 2, 3, 4

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.	R24	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(5)
2) RCS Loop ΔT	N.A.	R	Q	N.A	N.A	N.A	N.A	1, 2

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
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.	R24	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 Containment Ventilation Exhaust Radiation - 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.
(4) Except relays K612A, K614B, K615A, and K615B, which shall be tested, at a minimum, once per 18 months during refueling and during each Cold Shutdown unless they have been tested within the previous 92 days.
(5) For Mode 3, the Trip Time Delay associated with the Steam Generator Water Level-Low-Low channel must be less than or equal to 464.1 seconds.

3/4.4.3 PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.3 The pressurizer shall be OPERABLE with a water volume of less than or equal to 1600 cubic feet and two groups of pressurizer heaters each having a capacity of at least 150 kW.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one group of pressurizer heaters inoperable, restore at least two groups to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the Reactor trip breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The pressurizer water volume shall be determined to be within its limit at least once per 12 hours.

4.4.3.2 The capacity of each of the above required groups of pressurizer heaters shall be verified by measuring heater group power at least once per 92 days.

4.4.3.3 The emergency power supply for the pressurizer heaters shall be demonstrated OPERABLE at least once each REFUELING INTERVAL by transferring power from the normal to the emergency power supply and energizing the heaters.

SURVEILLANCE REQUIREMENTS

4.4.6.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere particulate or gaseous radioactivity monitor at least once per 12 hours;

b. Monitoring the containment structure sump inventory and discharge at least once per 12 hours;

c. Measurement of the CONTROLLED LEAKAGE to the reactor coolant pump seals at least once per 31 days when the Reactor Coolant System pressure is 2235 ± 20 psig with the modulating valve fully open. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4;

d. Performance of a Reactor Coolant System water inventory balance at least once per 72 hours, except when T_{avg} is being changed by greater than 5°F/hour or when diverting reactor coolant to the liquid holdup tank, in which cases the required inventory balance shall be performed within 12 hours after completion of the excepted operation; and

e. Monitoring the Reactor Head Flange Leakoff System at least once per 24 hours.

4.4.6.2.2 As specified in Table 3.4-1, Reactor Coolant System pressure isolation valves shall be demonstrated OPERABLE pursuant to Specification 4.0.5, except that in lieu of any leakage testing required by Specification 4.0.5, each valve shall be demonstrated OPERABLE by verifying leakage to be within its limit:

a. At least once each REFUELING INTERVAL during startup,

b. Prior to returning the valve to service following maintenance, repair or replacement work on the valve, and

c. Within 24 hours following valve actuation due to automatic or manual action or flow through the valve. After each disturbance of the valve, in lieu of measuring leak rate, leak-tight integrity may be verified by absence of pressure buildup in the test line downstream of the valve.

The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4.

c. By a visual inspection which verifies that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions. This visual inspection shall be performed:

   1) For all accessible areas of the containment prior to establishing CONTAINMENT INTEGRITY, and

   2) At least once daily of the areas affected within containment by containment entry and during the final entry when CONTAINMENT INTEGRITY is established.

d. At least once each REFUELING INTERVAL by a visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion;

e. At least once each REFUELING INTERVAL by:

   1) Verifying that each automatic valve in the flow path actuates to its correct position on a Safety Injection actuation test signal.

   2) Verifying that each of the following pumps start automatically upon receipt of a Safety Injection actuation test signal:

      a) Centrifugal charging pump,

      b) Safety Injection pump, and

      c) Residual Heat Removal pump.

f. By verifying that each of the following pumps develops the indicated differential pressure on recirculation flow when tested pursuant to Specification 4.0.5:

   1) Centrifugal charging pump $\geq$ 2400 psid,

   2) Safety Injection pump $\geq$ 1455 psid, and

   3) Residual Heat Removal pump $\geq$ 165 psid.

SURVEILLANCE REQUIREMENTS (Continued)

g. By verifying the correct position of each electrical and/or mechanical position stop for the following ECCS throttle valves:

1) Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE, and

2) At least once each REFUELING INTERVAL.

Charging Injection Throttle Valves	Safety Injection Throttle Valves
8810A	8822A
8810B	8822B
8810C	8822C
8810D	8822D

h. By performing a flow balance test, during shutdown, following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics and verifying that:

1) For centrifugal charging pumps, with a single pump running:

a) The sum of injection line flow rates, excluding the highest flow rate, is greater than or equal to 299 gpm, and

CONTAINMENT VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.7 One purge supply line and/or one purge exhaust line of the Containment Purge System may be open or the vacuum/pressure relief line may be open. The vacuum/pressure relief line may be open provided the vacuum/pressure relief isolation valves are blocked to prevent opening beyond 50° (90° is fully open). Operation with any two of these three lines open is permitted. Operation with the purge supply and/or exhaust isolation valves open or with the vacuum/pressure relief isolation valves open up to 50° shall be limited to less than or equal to 200 hours during a calendar year.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With a containment purge supply and/or exhaust isolation valve open or the vacuum/pressure relief isolation valves open up to 50° for more than 200 hours during a calendar year or the Containment Purge System open and the vacuum/pressure relief lines open, or with the vacuum/pressure relief isolation valves open beyond 50°, close the open isolation valve(s) or isolate the penetration(s) within 1 hour; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.7.1 The position of the containment purge supply and exhaust isolation valves and the vacuum/pressure relief isolation valves shall be determined closed at least once per 31 days.

4.6.1.7.2 The cumulative time that the purge supply and/or exhaust isolation valves or the vacuum/pressure relief isolation valves have been open during a calendar year shall be determined at least once per 7 days.

4.6.1.7.3 The vacuum/pressure relief isolation valves shall be verified to be blocked to prevent opening beyond 50° at least once each REFUELING INTERVAL.

SPRAY ADDITIVE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.2 The Spray Additive System shall be OPERABLE with:

a. A spray additive tank with a contained volume of between 2025 and 4000 gallons of between 30 and 32% by weight NaOH solution, and

b. Two spray additive eductors each capable of adding NaOH solution from the chemical additive tank to a Containment Spray System pump flow.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the Spray Additive System inoperable, restore the system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours; restore the Spray Additive System to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The Spray Additive System shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position;

b. At least once per 6 months by:

   1) Verifying the contained solution volume in the tank, and

   2) Verifying the concentration of the NaOH solution by chemical analysis.

c. At least once each REFUELING INTERVAL by verifying that each automatic valve in the flow path actuates to its correct position on a Containment Spray actuation test signal; and

d. At least once per 5 years by verifying both spray additive and RWST full flow from the test valve 8993 in the Spray Additive System.

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying a cooling water flow rate of greater than or equal to 1650* gpm to each cooler, and

3) Verifying that each containment fan cooler unit starts on low speed.

b. At least once each REFUELING INTERVAL by verifying that each containment fan cooler unit starts automatically on a Safety Injection test signal.

* The CFCU cooling water flow rate requirement of TS 4.6.2.3a.2) may not be met during Section XI testing and in Mode 4 during residual heat removal heat exchanger operation.

3/4.6.3 CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3 Each containment isolation valve# shall be OPERABLE.*

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With one or more of the isolation valve(s) inoperable, maintain at least one isolation valve OPERABLE in each affected penetration that is open and:

a. Restore the inoperable valve(s) to OPERABLE status within 4 hours, or

b. Isolate each affected penetration within 4 hours by use of at least one deactivated automatic valve secured in the isolation position, or

c. Isolate each affected penetration within 4 hours by use of at least one closed manual valve or blind flange; or

d. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

*Locked or sealed closed valves may be opened on an intermittent basis under administrative control.

SURVEILLANCE REQUIREMENTS

4.6.3.1 Each containment isolation valve shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by performance of a cycling test, and verification of isolation time.

4.6.3.2 Each containment isolation valve shall be demonstrated OPERABLE at least once each REFUELING INTERVAL by:

a. Verifying that on a Phase "A" Isolation test signal, each Phase "A" isolation valve actuates to its isolation position;

b. Verifying that on a Phase "B" Isolation test signal, each Phase "B" isolation valve actuates to its isolation position; and

c. Verifying that on a Containment Ventilation Isolation test signal, each containment ventilation isolation valve actuates to its isolation position.

See AD13.DC1 for List of Containment Isolation Valves

ELECTRIC HYDROGEN RECOMBINERS

LIMITING CONDITION FOR OPERATION

3.6.4.2 Two independent Hydrogen Recombiner Systems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTION:

With one Hydrogen Recombiner System inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT STANDBY within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.6.4.2 Each Hydrogen Recombiner System shall be demonstrated OPERABLE:

a. At least once each REFUELING INTERVAL by verifying, during a Recombiner System functional test, that the minimum heater sheath temperature increases to greater than or equal to 700°F within 90 minutes. Upon reaching 700°F, increase the power setting to maximum power for 2 minutes and verify that the power meter reads greater than or equal to 60 kW; and

b. At least once each REFUELING INTERVAL by:

   1) Performing a CHANNEL CALIBRATION of all recombiner instrumentation and control circuits,

   2) Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiner enclosure (i.e., loose wiring or structural connections, deposits of foreign materials, etc.), and

   3) Verifying the integrity of all heater electrical circuits by performing a resistance to ground test following the above required functional test. The resistance to ground for any heater phase shall be greater than or equal to 10,000 ohms.

SURVEILLANCE REQUIREMENTS (Continued)

(2) Verifying that each non-automatic valve in the pump flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

(3) Verifying that each non-automatic valve in both steam supplies to the steam turbine-driven pump that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 92 days on a STAGGERED TEST BASIS by: testing the steam turbine-driven pump and motor-driven pumps pursuant to Specification 4.0.5*. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 for the steam turbine-driven pump.

c. At least once each REFUELING INTERVAL by verifying that each auxiliary feedwater pump starts and valve opens* as designed automatically upon receipt of an Auxiliary Feedwater Actuation test signal.

*For the steam turbine-driven pump, when the secondary steam supply pressure is greater than 650 psig.

STEAM GENERATOR 10% ATMOSPHERIC DUMP VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.6 Four steam generator 10% atmospheric dump valves (ADVs) with the associated block valves open and associated remote manual controls, including the backup air bottles, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one less than the required number of 10% ADVs OPERABLE, restore the inoperable steam generator 10% ADV to OPERABLE status within 7 days; or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With two less than the required numbered of 10% ADVs OPERABLE, restore at least one of the inoperable steam generator 10% ADVs to OPERABLE status within 72 hours; or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.6 Each steam generator 10% ADV, associated block valve and associated remote manual controls including the backup air bottles shall be demonstrated OPERABLE:

a. At least once per 24 hours by verifying that the backup air bottle for each steam generator 10% ADV has a pressure greater than or equal to 260 psig, and

b. At least once per 31 days by verifying that the steam generator 10% ADV block valves are open, and

c. At least once each REFUELING INTERVAL by verifying that all steam generator 10% ADVs will operate using the remote manual controls and the backup air bottles.

3/4.7.3 VITAL COMPONENT COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3.1 At least two vital component cooling water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With only one vital component cooling water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.3.1 At least two vital component cooling water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position; and

b. At least once each REFUELING INTERVAL, by verifying that each automatic valve servicing safety-related equipment actuates to its correct position on a Safety Injection or Phase "B" Isolation test signal, as appropriate.

c. At least once each REFUELING INTERVAL, by verifying that each component cooling water pump starts automatically on an actual or simulated actuation signal.

3/4.7.4 AUXILIARY SALTWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4.1 At least two auxiliary saltwater trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With only one auxiliary saltwater train OPERABLE, restore at least two trains to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.1 At least two auxiliary saltwater trains shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

4.7.4.2 Each auxiliary saltwater pump shall be demonstrated OPERABLE at least once each REFUELING INTERVAL by verifying that each pump starts automatically on an actual or simulated actuation signal.

ATTACHMENT D

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS
FOR EACH PROPOSED TS CHANGE

CONTENTS

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 1 -- TECHNICAL SPECIFICATION TABLE 1.1
FREQUENCY NOTATION

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS Table 1.1, "Frequency Notation," as follows:

> Add a new notation "R24, REFUELING INTERVAL," with a frequency of "At least once per 24 months."

The proposed change is provided in the marked-up copy of TS page 1-8 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

Generic Letter (GL) 91-04 recommends changing the surveillance interval notation in Table 1.1 to include the term "REFUELING INTERVAL" along with the "R" notation to define the frequency for surveillances that are specified to be performed once each refueling interval. The proposed TS change should also modify the frequency for this surveillance interval notation from "At least once per 18 months" to "At least once per 24 months" to define the nominal frequency for surveillances that are specified to be performed each REFUELING INTERVAL or with the "R" notation. The bounding time interval for these surveillances would then be 30 months under the provision of TS 4.0.2 that allows a surveillance to be extended by 25 percent of the specified interval.

PG&E plans to adopt a modified version of the GL recommendation by retaining the existing "R" notation with a frequency of "At least once per 18 months" and adding a new notation of "R24, REFUELING INTERVAL," with a frequency of "At least once per 24 months." This will allow clear differentiation between 24-month and 18-month surveillance intervals.

C. SAFETY EVALUATION

The proposed change to TS Table 1.1 to add a new notation for 24-month surveillance intervals is an administrative change that, in and of itself, has no effect on plant safety. The safety implications of applying this change to other TS surveillance requirements are evaluated on a case-by-case basis.

D. NO SIGNIFICANT HAZARDS EVALUATION

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed frequency notation addition is an administrative change that has no affect on the probability or consequences of an accident.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed frequency notation addition is an administrative change that does not affect potential accidents.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   The proposed frequency notation addition is an administrative change that does not affect plant safety.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 2 -- TECHNICAL SPECIFICATION 4.0.2 BASES SECTION - LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise the Bases section for TS 4.0.2, as follows, to reflect the guidance in Generic Letter (GL) 91-04:

> Revise the Bases section for TS 4.0.2 to change the surveillance frequency from an 18-month surveillance interval to at least once each REFUELING INTERVAL. Also, add guidance from GL 91-04 with respect to the safe conduct of refueling interval surveillances.

The proposed change is provided in the marked-up copy of TS page B 3/4 0-2 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

GL 91-04 recommends both changing the surveillance interval notation in the Bases section for TS 4.0.2 from an 18-month surveillance interval to the term "REFUELING INTERVAL" and adding additional guidance with respect to the safe conduct of refueling interval surveillances. PG&E proposes to adopt the revision as stated by GL 91-04 for the Bases section of TS 4.0.2.

C. SAFETY EVALUATION

The proposed change to the Bases section of TS 4.0.2 to change the surveillance interval notation and add guidance regarding safe conduct of refueling interval surveillances is an administrative change that, in and of itself, has no effect on plant safety. The safety implications of applying this change to other TS surveillance requirements are evaluated on a case-by-case basis.

D. NO SIGNIFICANT HAZARDS EVALUATION

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

The proposed change to the Bases section for TS 4.0.2 is an administrative change that has no affect on the probability or consequences of an accident.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The proposed change to the Bases section for TS 4.0.2 is an administrative change that does not affect potential accidents.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   The proposed change to the Bases section for TS 4.0.2 is an administrative change that does not affect plant safety.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATION

ITEM 3

TECHNICAL SPECIFICATION 3/4.1.3.3
REACTIVITY CONTROL SYSTEMS

POSITION INDICATION SYSTEM - SHUTDOWN

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 3/4.1.3, "Reactivity Control Systems - Movable Control Assemblies," as follows:

> TS 4.1.3.3, regarding verifying that the digital rod position indicators agree with the demand position indicators within 12 steps when exercised over the full range of travel, from at least once per 18 months to at least once each REFUELING INTERVAL.

The proposed changes to the TS are noted in the marked-up copy of TS page 3/4 1-19 in Attachment B. The proposed new TS pages are provided in Attachment C.

B. BACKGROUND

Control rods are withdrawn or inserted by the control rod drive mechanisms (CRDMs) to control reactor power. The control rods are divided among control banks and shutdown banks. Each bank is further divided into groups to provide for precise reactivity control. The operability, including position indication, of the control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Rod position indication is required to assess operability and misalignment of the control rods. The axial position of the shutdown and control rods are determined by two separate and independent systems: the Demand Position Indicators (group step counters) and the Digital Rod Position Indication (DRPI) system.

The group step counters count the pulses issued by the rod control system to move the rods. Individual rods in a group all receive the same signal to move and should all be at the position indicated by the group step counter for that group. The demand position indication system is precise, and indicates rod position to ± 1 step (± 5/8 inch). If a control rod does not move one step for each demand pulse, the step counter would still count the pulse and incorrectly reflect the position of the rod.

The DRPI system provides an indication of actual control rod position, but at a lower resolution than provided by the step counters. DRPI receives inductive signals from a series of coils spaced along the control rod guide tube. When the control rod drive assembly penetrates a coil, the coil sends a signal to DRPI. The center-to-center coil distance is 3.75 inches, so the full system resolution is six steps. Each coil's position is stated at its mid-position. Therefore, the accuracy of the full system is +/- 4 steps of actual rod position, which includes an uncertainty of one step for thermal expansion and mechanical positioning of the coil stack.

To ensure the reliability of the system, the inductive coils are connected alternately to data system A or B. If one of the data systems fails, DRPI will go to half-accuracy with an effective coil spacing of 7.5 inches, or 12 step resolution. The accuracy of the system when operating on Data A or Data B only is up to +/- 10 steps of actual rod position including uncertainty, depending on which data system is out of service.

The rod position TS requires DRPI and the group step counters to agree within 12 steps across the entire range of travel for each control rod. With a deviation of 12 steps between the group step counter and DRPI, if DRPI is operating in half-accuracy, the maximum deviation between actual rod position and the demand position is less than 24 steps, or 15 inches.

C. SAFETY EVALUATION

The DRPI verification surveillance is performed at least once each refueling outage when the plant is in Modes 3, 4, or 5. As part of the reactor disassembly required to refuel the reactor, the DRPI cables are uncoupled from the control rod coil stacks on each control rod guide tube and removed from the reactor head. Therefore, the surveillance is performed after the reactor core has been reloaded and reactor and DRPI reassembly completed.

The surveillance is performed with both data systems of DRPI. The control rod drive system is placed in service, and each bank of rods is withdrawn incrementally. Comparisons are made between the DRPI and the demand step counter for each rod. After the bank is fully withdrawn, it is reinserted and the position at which each rod bottom indicator actuates is recorded.

Assurance that the DRPI system is operable when the plant is in Modes 1 or 2 is provided by TS 4.1.3.1.1 and TS 4.1.3.2. TS 4.1.3.1.1 requires the position of each full-length rod to be verified within the group limit using the individual rod positions (DRPI) at least once per 12 hours. TS 4.1.3.2 requires that the group step counters and DRPI be verified to agree within ± 12 steps every 12 hours. For

either TS, if the rod position deviation monitor is inoperable, the verifications are completed at least once per four hours.

Operating History

DRPI has been available whenever the reactor trip breakers were closed and rods capable of being withdrawn, as required by TS. Problems with DRPI train power supplies and display cards have occasionally affected one train or the other, but have not rendered the system inoperable. These problems were detected by operator observation of DRPI during control rod movement or during operator investigation of alarms associated with DRPI. The DRPI system and group step counters have provided the required control rod position resolution whenever required to be operable throughout the review period (since January 1990).

Surveillance History

Data from 22 DRPI surveillance tests were reviewed covering six refueling outages and initial operation for each of the two Diablo Canyon units. Three tests identified equipment problems associated with DRPI.

Tests in December 1989 and January 1990 in Unit 1 identified three cases in which there was a DRPI Data A or Data B failure. In both cases, the test result was satisfactory in the half-accuracy mode (Data A or Data B only selected) and the full accuracy of DRPI was restored by replacing a decoder-encoder card for the affected rod. Because DRPI was operable in half-accuracy, these cases did not represent failures.

The test performed in October 1991 in Unit 2 identified that DRPI was operable for all rods except for two. This condition was a test failure for the affected rods. After investigation it was found that one of the DRPI cable connectors had a loose wire strand that shorted two pins in the connector. Another DRPI cable connector had a broken connector pin. These conditions were repaired and the DRPI subsequently tested satisfactorily. These cable connector anomalies were detected during the normal course of the maintenance and testing of DRPI after reactor refueling. During refueling operations, the reactor head is removed and the DRPI cables are disconnected, then subsequently reconnected and tested. The TS surveillance is one of the tests that is performed after the DRPI cables are reconnected. The anomalies identified were due to the refueling activities performed and were not due to time-related degradation of the DRPI system.

Maintenance History

The maintenance history for DRPI was reviewed back to January 1990 for both units. The DRPI system is disassembled each outage when the reactor vessel head is removed. Consequently, problems are commonly identified during the

normal maintenance verifications performed after reconnecting the DRPI cables and repowering the system following reactor refueling.

Extensive maintenance and surveillance tests are performed each refueling outage to verify functionality. Maintenance verifications include coil stack, cable, detector and encoder card checks, and verification of the display functions of the control room indicators. Problems were identified and resolved with DRPI encoder-detector cards, display input/output cards, and cables and connectors. The problems were due to the removal of power, disassembly, maintenance, re-assembly, and repowering of the system after reactor refueling. They were not related to the normal operation of DRPI and are not dependent on fuel cycle length.

In 1994, the DRPI cables in containment were replaced from the coil stacks to the bulkhead for both Diablo Canyon units due to accumulated degradation and wear caused by refueling activities. The cable internal insulation had hardened due to time and heating. Cable movement during outages could cause the hardened insulation to crack and damage the conductors. Although insulation hardening is time-dependent, the actual failure mechanism is related to mechanical manipulation of the cables, and is dependent on outage activities, not fuel cycle length. Failures due to conductor damage are identified during post-assembly maintenance each outage. The control room indicator assemblies were refurbished during the same outages. The post-maintenance surveillance tests were satisfactory.

Conclusion

The review of the surveillance, maintenance, and operating history of the Diablo Canyon DRPI system supports the conclusion that the effect on safety of extending the surveillance interval is small. No DRPI time-dependent failure history is evident. The identified problems were detected by routine operator observation in response to system alarms and rod position surveillance tests. Disassembly and reassembly performed during refueling outages caused the one failed DRPI surveillance. The maintenance program for DRPI has been reviewed and determined to support extension of the maintenance intervals.

PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by extending the surveillance interval from every 18 months to every refueling outage.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change to TS 4.1.3.3 extends the surveillance interval for verification that the DRPI agree with the demand position indicators within 12 steps when exercised over the full range of travel, from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the verifications are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the DRPI system indicates that the DRPI system will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this instrumentation during normal plant operation.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the DRPI system will continue to effectively perform its design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   Evaluation of historical surveillance and maintenance data indicates there have been few problems with the DRPI system. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and

there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 4 -- TECHNICAL SPECIFICATION 4.1.3.4c.
REACTIVITY CONTROL SYSTEMS - ROD DROP TIME

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 3/4.1.3.4, "Rod Drop Time," as follows:

> TS 4.1.3.4c., regarding rod drop time, would be revised to change the surveillance frequency from at least once per 18 months to at least once each REFUELING INTERVAL.

The proposed change is noted in the marked-up copy of TS page 3/4 1-20 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

Operability of the control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Control rods are used to provide rapid insertion of negative reactivity upon reactor trip and control of the core power distribution during reactor operation. Control rods are divided into control banks and shutdown banks. Each bank may be further subdivided into groups to provide precise reactivity control. The shutdown banks are maintained in the fully withdrawn position in Modes 1 and 2. The control bank rods are moved in overlapping patterns to control core power distribution. All of the rods are positioned by the electromagnetic gripper latches of the control rod drive mechanisms (CRDMs).

In the event of a reactor trip, fast negative reactivity insertion is achieved by removing electrical power from the CRDMs. When power is removed from the electromagnets, the gripper latches automatically release the control rods, allowing the rods to fall into the core by gravity. Dashpots built into the bottom of the guide tubes in the fuel assembly act to slow and stop the falling rods prior to rod bottoming.

The TS surveillance requires rod drop time to be less than or equal to 2.7 seconds for a fully withdrawn rod, starting from decay of stationary gripper coil voltage and ending at dashpot entry. This time is consistent with the rod drop time assumed in the safety analysis. Rod drop time is verified for all rods during each refueling interval, whenever the vessel head is removed, and on individual rods whenever maintenance is performed on the control rod drive

system that could affect the drop time of those rods. Measuring rod drop time prior to reactor criticality verifies that the reactor internals and rod drive mechanisms will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time.

The rod drop time applies to cores loaded with Vantage 5 or a combination of LOPAR and Vantage 5 fuel assemblies. The rod drop time will remain the same for the extended cycle Vantage+ fuel and mixed cores of Vantage+ and Vantage 5 fuel assemblies (including features such as ZIRLO cladding, annular pellets, higher-enriched integral fuel burnable absorbers, and coated rods).

C. SAFETY EVALUATION

Rod drop timing tests are completed at the end of each refueling outage when the plant is at normal operating pressure and no-load temperature, with all reactor coolant pumps running. The function of the rod drop test is to detect increasing rod drop times that could result in a drop time in excess of that assumed in the safety analysis. Increasing rod drop times may result from increased friction in the rod channel caused by interference from the reactor internals or rod drive mechanisms, swelling or movement of the adjacent fuel, excessive rod wear, or foreign materials inadvertently deposited in the core.

Fuel swelling or movement may be time-dependent, but will not change from the current analysis. As noted in FSAR Update, Section 4.2.3.3.1.1, "Rod Cluster Control Assembly," the control rods are provided a clear channel for insertion by the guide thimbles of the fuel assemblies, which provide a physical barrier between the fuel rod and the intended insertion channel. Distortion of the fuel rods by bending cannot apply sufficient force to damage or significantly distort the guide thimble. Fuel rod distortion by swelling, though precluded by design, would be terminated by fracture before contact with the guide thimble occurs. If such were not the case, a force reaction at the point of contact would cause a slight deflection of the guide thimble. The radius of curvature of the deflected shape of the guide thimbles would be sufficiently large to have a negligible influence on control rod insertion. Further, Westinghouse testing has evaluated the effect of extended cycle operation on fuel assembly bowing and has concluded that potential bowing will have no impact on rod drop time. The Vantage+ fuel is dimensionally the same as Vantage 5 fuel. The Vantage 5 fuel currently used has not impacted the rod drop times, indicating satisfactory dimensional stability.

Interference, excessive rod wear, or foreign materials in the core that could impact rod drop time would be expected to result in mechanically stuck or slow rods and, hence, would be detected during rod movement testing. Stuck or slow

rods are usually detected by rod position monitoring, not rod drop timing tests. The control bank and shutdown bank rods are controlled in groups of two to five rods that receive identical movement orders. A sticking rod would be noticed by the operators when they perform rod alignment verifications during startups, shutdowns, or operations to change power level. Additionally, there is a surveillance requirement to move all control rods at least 10 steps each quarter during power operations. Finally, immediately after any reactor trip, all rods are verified to have fully inserted into the core.

Operating History

A review of the operational history of the Diablo Canyon control rods identified no instances of stuck or slow control rods sufficient to have caused their design rod drop times to be exceeded.

Surveillance History

Data from thirteen completed surveillance tests for rod drop time were reviewed, covering six refueling outages for each of the two Diablo Canyon units, and prior to Cycle 1 for Unit 2. The average rod drop time and the maximum rod drop time for the slowest rod were identified in each test. In every test, all control rods met the current rod drop time requirement of 2.7 seconds by a large margin. In testing performed in 1994, the average rod drop times were 1.35 seconds in both units. The drop time for the slowest rod was a maximum of 0.06 seconds longer than the drop time for the average rod. No time dependence was discernible in either the average or the slowest rod drop times for either unit from 1986 to 1994.

Maintenance History

A review of the maintenance history of the Diablo Canyon control rods identified no instances of repair or replacement. The control rods were eddy current tested in 1992 (Unit 1) and 1994 (Unit 2) as part of the actions taken to monitor rod wear. Eddy current testing is performed to detect fretting wear and tip cracking of the control and shutdown bank rods. The results of the eddy current tests indicate that all of the control rods are wearing at an acceptable rate and will not be adversely affected by extending the refueling interval to 24 months.

Industry Experience

Industry experience and generic NRC communications were reviewed, and no reports were noted that affect the maintenance or operation of Diablo Canyon's control rods.

Summary

The surveillance, maintenance, and operational history of the Diablo Canyon control rods supports the conclusion that the effect on safety of extending the surveillance interval is small. No time-related dependence is evident for control rod drop times. Stuck rods are most likely to be detected by routine on-line operations and surveillance tests. PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change to TS 4.1.2.3c extends the surveillance interval for testing of the rod drop time from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which control rod drop time tests are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the control rods indicates that the control rods will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of the control rods during normal plant operation.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the control rods will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

Evaluation of historical surveillance and maintenance data indicates there have been no problems with the control rod drop times. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition for operation, and there are no hardware changes that would impact existing safety analysis acceptance criteria.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 5 THROUGH 13

TECHNICAL SPECIFICATIONS
INSTRUMENTATION

REACTOR TRIP SYSTEM INSTRUMENTATION
TS 3/4.3.1 TS 4.3.1.1 TABLE 4.3-1
Functional Units 1, 18, 19, 24

ESFAS INSTRUMENTATION
TS 3/4.3.2 TS 4.3.2.1 TABLE 4.3-2
Functional Units 1.a, 3.a.1), 3.b.1), 4.a, 8.c

TRIP ACTUATING DEVICE OPERATIONAL TESTS

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the following nine trip actuating device operational test surveillance requirements to change the surveillance frequency from "R", at least once per 18 months, to "R24", at least once per REFUELING INTERVAL. The instrumentation functional units proposed for revision in this safety evaluation do not require setpoint drift evaluation.

TS 3/4.3.1, "Reactor Trip System Instrumentation," TS 4.3.1.1, Table 4.3-1:

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5. Functional Unit 1, Manual Reactor Trip

6. Functional Unit 18, Safety Injection Input from ESF

7. Functional Unit 19, Reactor Coolant Pump Breaker Position Trip

8. Functional Unit 24, Reactor Trip Bypass Breaker

TS 3/4.3.2, "Engineered Safety Features Actuation System Instrumentation," TS 4.3.2.1, Table 4.3-2:

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9. Functional Unit 1.a, Safety Injection, Manual Initiation

10. Functional Unit 3.a.1), Containment Isolation, Phase "A" Isolation, Manual

11. Functional Unit 3.b.1), Containment Isolation, Phase "B" Isolation, Manual

12. Functional Unit 4.a, Steam Line Isolation, Manual

13. Functional Unit 8.c, ESFAS Interlocks, Reactor Trip, P-4

The proposed changes are provided in the marked-up copies of TS pages 3/4 3-10, 3/4 3-11, 3/4 3-12, 3/4 3-32, 3/4 3-33, 3/4 3-34, and 3/4 3-35 in Attachment B. The proposed new TS pages are provided in Attachment C.

B. BACKGROUND

The reactor trip system (RTS) functions to ensure that the reactor core and reactor coolant system (RCS) are prevented from exceeding their safety limits during normal operation and design basis anticipated operational occurrences. The RTS assists the Engineered Safety Features Actuation System (ESFAS) in mitigating the consequences of accidents. Most of the functional units of the RTS and ESFAS initiate actuation signals based on inputs from process instrumentation. The RTS or ESFAS is actuated when the inputs exceed their setpoints.

Several of the functional units that are part of the RTS and ESFAS receive actuation signals from manually operated switches, circuit breaker auxiliary contact inputs, or solid state protection system (SSPS) logic states. These units do not experience time-dependent setpoint drift. Because there is no way to test these units at power without causing reactor trips, they are tested during refueling outages by performance of a trip actuating device operational test (TADOT). A TADOT consists of operating the trip actuating device and verifying the operability of alarm, interlock and/or trip functions. A brief description of the components of these functional units follows.

Manual Reactor Trip

Manual reactor trip is provided by two switches in the control room. Each switch sends trip signals to all four of the reactor trip breakers' (RTBs) shunt trip circuits.

Reactor Trip Breakers

The main RTBs have two diverse trip mechanisms. First, an undervoltage trip attachment (UVTA) is mounted on the breaker. If power is removed from this attachment by the SSPS actuation logic, the attachment operates the breaker trip bar directly. Second, a shunt trip relay is mounted in the switchgear cubicle with contacts wired to the breaker trip coil circuit. If power is removed by the SSPS actuation logic, the relay de-energizes, the shunt trip contacts close to energize the breaker trip coil, and the breaker opens. The trip coil circuits on the main RTBs are also actuated by the manual reactor trip and manual SI switches.

The bypass RTBs have UVTAs, but do not have shunt trip relays. The trip coil circuit on the bypass breakers is actuated by the manual reactor trip, manual SI, and local shunt trip switches.

SI Input from ESF Reactor Trip

The safety injection (SI) input from ESF reactor trip is generated whenever the SSPS logic for SI initiation is satisfied. This feature is an integral part of the actuation logic of the SSPS. When SI logic is satisfied, SSPS concurrently generates a reactor trip signal to the RTBs and an SI signal to the ESFAS.

Reactor Coolant Pump Breaker Position Reactor Trip

The reactor coolant pump (RCP) breaker position reactor trip is generated by auxiliary contacts located in the primary and backup RCP breaker cubicles. The contacts for the primary and backup breakers for each RCP are wired in series, so that if either breaker is open, a signal is generated to the SSPS. At power levels above P-7 (approximately 10 percent), if two out of four of the RCP loops have a circuit breaker open, a reactor trip is generated. The RCP breaker trip provides backup protection for loss of flow conditions and is not credited in any safety analysis.

Manual ESF Actuations

The manual SI, phase "A" isolation and phase "B" isolation switches send actuation signals directly to the output of the SSPS logic section. Upon switch actuation, the SSPS energizes appropriate master and slave relays to generate

the required ESFAS initiation. The manual SI switches also send actuation signals directly to the main and bypass RTBs' shunt trip circuits.

Manual steam line isolation is provided by the four main steam isolation valve (MSIV) control switches located on the control boards. This signal does not go to the SSPS since no subsequent actuation is required.

Reactor Trip Interlock, P-4

The ESFAS interlock signal for reactor trip, P-4, is generated by RTB contact logic circuits whenever sufficient main and bypass RTBs open. The logic is generated using a combination of auxiliary and cell interlock contacts. The cell interlock contacts on the RTBs are used to determine what configuration of main and bypass reactor trip breakers are racked in.

The auxiliary contacts on each main and bypass RTB directly generate the P-4 main turbine trip. Additional auxiliary contacts send a P-4 signal to the logic section of the SSPS. The SSPS generates SI automatic blocking logic, feedwater isolation signals, and other nonsafety-related actuations upon receiving a P-4 signal.

C. SAFETY EVALUATION

The TADOTs for the nine functional units are performed on a refueling frequency. The frequency of surveillance is based on the potential for an unplanned transient if the surveillance were performed with the reactor at power and the need to perform these tests under the conditions that apply during a plant outage. However, many portions of these systems are tested more frequently.

Assurance of RTS and ESFAS operability is provided by the automatic actuation logic testing of the SSPS. Logic testing is performed on a staggered monthly frequency per TS Table 4.3-1 Functional Unit 22, automatic trip and interlock logic, and TS Table 4.3-2 units requiring automatic actuation logic and actuation relay testing. This testing ensures that the correct automatic signals will be generated by the SSPS when required.

Assurance of main and bypass RTB operability is also provided by staggered monthly testing. The breakers are tested per TS Table 4.3-1 Functional Units 21 (RTBs) and 24 (RTB bypass breakers) during performance of the staggered monthly logic testing of the SSPS. As required by Table Notations 10 and 15, this testing separately verifies the operability of the undervoltage and shunt trip attachments of the RTBs and tests the local manual shunt trip of the bypass RTBs.

Assurance of MSIV operability is provided by stroke testing performed for TS 4.7.1.5 and TS 4.0.5 on a cold shutdown frequency.

Operating History

A review of the operating history of the major components used to fulfill the specified RTS and ESFAS functions was completed. The review extended back to January 1990, at a minimum. Many of these components are challenged when reactor trips or SIs occur. For those functions that have been challenged by operational transients, no failures to actuate were observed in the review period.

Surveillance History

Table 4.3-1 Functional Unit 1 verifies manual reactor trip. The TADOT for this feature includes the Table Notation 14 requirement to independently verify the operability of the undervoltage and shunt trip circuits for the RTBs and verify the operability of the bypass breaker trip circuits.

Twenty-two refueling surveillance tests were reviewed for the manual reactor trip function, covering each protection train on each unit for the last six refueling outages. The tests covered the manual reactor trip switches and main and bypass RTB operability verifications for each protection train. The review confirmed that there were no failures or problems in meeting the TS with any of the components.

Table 4.3-1 Functional Unit 18 verifies reactor trip on receipt of the SI input from ESF. This feature is an integral part of the RTS and ESFAS actuation logic of the SSPS. The actuation logic is tested every 62 days on a staggered monthly frequency for each of the SSPS trains.

Ninety-four staggered monthly surveillance tests were reviewed covering the SI input from ESF operability verification. A minimum of 22 tests were reviewed for each SSPS train on each unit. The review confirmed that there were no failures or problems in meeting this TS in the last three years.

Table 4.3-1 Functional Unit 19 verifies the RCP breaker position reactor trip. Only the primary breaker contacts are required to be surveilled for the TS since the backup breakers are provided for penetration overcurrent protection only.

Thirteen refueling surveillance tests were reviewed for the RCP breaker position reactor trip operability verification, covering both units for the last six refueling outages. The review confirmed that there were no failures or problems in meeting the TS with any of the components.

Table 4.3-1 Functional Unit 24 verifies the automatic undervoltage trip of the bypass RTBs.

Ninety-four staggered monthly surveillance tests were reviewed covering the SI input from ESF operability verification. A minimum of 22 tests were reviewed for each SSPS train on each unit for the last three years. The test is performed with the main RTB fully racked in and closed and the bypass RTB for the train being tested racked into test position and closed. An automatic undervoltage reactor trip signal is generated in the SSPS, and RTB tripping is verified for both the main and bypass RTBs. The review confirmed that there was one failure of the undervoltage trip of a bypass RTB.

In November 1994, a Unit 2 bypass breaker failed to open on receipt of an automatic undervoltage trip signal. The main RTB opened satisfactorily, indicating that the trip signal was correctly generated. The bypass breaker UVTA was determined to be mechanically bound in the energized position. The UVTA was first installed on the breaker in September 1994, and was successfully tested twice before failing.

The root cause investigation attributed the failure to either (1) damage of the UVTA during lubrication or installation, or (2) a foreign object wedging the trip lever assembly into the latched position, although no foreign object was found. Records indicated that the switchgear had been inspected to ensure that all foreign objects, tools, and weights were removed from the switchgear enclosure and breaker element after the September 1994 maintenance. As a prudent action, additional guidance was added to the breaker maintenance procedure on UVTA lubrication and installation. This event was determined to be a random failure, and is not indicative of a recurring problem.

Table 4.3-2 Functional Units

1.a	Manual SI actuation
3.a.1)	Manual phase "A" isolation actuation
3.b.1)	Manual phase "B" isolation actuation

Twenty-two refueling surveillance tests were reviewed for the manual ESFAS actuation functions, covering each protection train on each unit for the last six refueling outages. The review confirmed that there were no failures or problems in meeting the TS with any of the components.

Table 4.3-2 Functional Unit 4.a verifies manual steam line isolation. Manual steam line isolation at Diablo Canyon is performed by closing the four MSIV control switches. Therefore, this surveillance is satisfied by the same test used to stroke the MSIVs for the In-service Test Program.

Fifty-two cold shutdown surveillance tests were reviewed for MSIV operability verification, covering the period from November 1986 to August 1995. A minimum of 14 tests were reviewed for each of the four valves on each unit. The review confirmed that there were no failures of any MSIVs to close during this period, and one instance where a valve exceeded its stroke time.

In June 1987, Unit 2 FCV-44 stroked closed in 7.1 seconds, exceeding the TS 4.7.1.5 limit of 5.0 seconds. The valve was repacked and the stem lubricated, and successfully retested. No problems were noted in subsequent testing.

Table 4.3-2 Functional Unit 8.c verifies operation of the reactor trip interlock, P-4. Thirty refueling surveillance tests were reviewed for P-4 interlock operability verification, covering the last four refueling cycles on each unit. Two overlapping tests are completed each outage to provide satisfactory verification of the turbine trip and SSPS logic functions associated with P-4. The review confirmed that there was one problem in meeting the TS in the last six years.

In October 1991, the Unit 2 Train B RTB did not properly make up its cell interlock contacts during the test. When the RTBs were closed, a reactor trip condition was still indicated by a plant annunciator. Root cause investigation indicated that the mounting bracket for the cell interlock contact blocks located in the switchgear cubicles was bending when the breakers were racked in, and could cause the cell interlock switches to fail to make up properly. Bracket reinforcements were installed in both units during their next refueling outages. Subsequent testing has been satisfactory.

Maintenance History

A review of the maintenance history for the last six years (from January 1990) for the components of the nine TADOTs was completed. This equipment is in the scope of the Reliability-Centered Maintenance Program.

Most of the components cannot be maintained at power since their operation would cause a plant transient. The RTB and RCP breakers receive routine maintenance at scheduled intervals. The manual switches and SSPS logic section have no maintenance requirements other than the extensive testing performed at various intervals. The SSPS power supplies receive periodic inspection and maintenance to ensure reliability.

Table 4.3-1 Functional Unit 1 verifies manual reactor trip and the proper functioning of the undervoltage and shunt trips of the RTBs.

The functioning of the annunciation and trip contacts on the reactor trip switches are verified each refueling outage. The switches receive very little use during the fuel cycle and, consequently, wear over the fuel cycle is minimal. The manual reactor trip switches have not required maintenance in the period reviewed.

The functioning of the UVTAs and shunt trip relays of the RTBs are verified every 62 days. In addition, the breakers receive vendor recommended maintenance each outage. This maintenance has been evaluated and determined to be related to the number of cycles a breaker receives, rather than the period that it is in service. The expected RTB breaker cycles will not challenge the vendor's guidelines over a longer fuel cycle.

Other than the failure of a single UVTA on a bypass breaker noted above in the surveillance history for Functional Unit 24, there have been no failures that would affect the ability of the RTBs to perform their safety function during the review period. In addition, these breakers may be changed out for maintenance, if required.

Table 4.3-1 Functional Unit 18 verifies reactor trip on receipt of the SI input from ESF. The functioning of the appropriate SSPS logic is verified every 62 days. There are no moving parts involved in generating the trip logic, so mechanical wear is not an applicable failure mechanism. The SSPS logic components for this function have not required any maintenance during the review period.

Table 4.3-1 Functional Unit 19 verifies the RCP breaker position reactor trip. The functioning of this reactor trip input is verified each refueling outage. The RCP breakers are maintained during refueling outages, when the RCPs can be shutdown. The breakers are rarely exercised during the fuel cycle, as the RCPs normally run continuously. Consequently, the breakers exhibit few signs of wear. No breaker problems have been noted that would affect the ability of the breakers to initiate the reactor trip signal or open on command during the review period.

Table 4.3-1 Functional Unit 24 verifies the automatic undervoltage trip of the bypass RTBs. The functioning of the bypass RTBs UVTA is verified every 62 days during SSPS logic testing. In addition, the breakers receive extensive vendor recommended maintenance each refueling outage to ensure their operability. As noted in the surveillance section, one new UVTA failed in 1994 on Unit 2. Extensive root cause investigation determined that it was an isolated problem. No other breaker problems have been noted that would affect the ability of the breakers to initiate a reactor trip on command during the review period.

Table 4.3-2 Functional Units

1.a	Manual SI actuation
3.a.1)	Manual phase "A" isolation actuation
3.b.1)	Manual phase "B" isolation actuation

The functioning of the annunciation and trip contacts on these switches are verified each refueling outage. These switches receive little or no use during the fuel cycle and, consequently, wear over the fuel cycle is minimal. None of the manual actuation switches have required maintenance during the review period.

Table 4.3-2 Functional Unit 4.a verifies manual steam line isolation. The functioning of the MSIV manual control switches is verified when the unit is shutdown. The MSIVs are not stroked at power and, consequently, the switch circuits receive minimal wear. The valve operating solenoids are normally de-energized and do not experience accelerated aging due to self-heating. Comprehensive surveillance and maintenance activities are performed on these valves and their associated equipment each outage to verify internal valve condition and backup circuit functionality. No failure mechanisms have been noted that have the potential to degrade the performance of the MSIVs over a longer fuel cycle.

By design, the MSIVs seat tightly on closure with a minimal differential pressure across the valve. Available steam flow ensures closure of the valves in Modes 1, 2, or 3, where they are required. No problems have been noted that would affect the ability to manually close the MSIVs in these modes during the review period.

Table 4.3-2 Functional Unit 8.c verifies operation of the reactor trip interlock, P-4. The interlock is provided by auxiliary contacts of the RTBs. The interlock contacts for P-4 are cycled every 62 days during actuation logic and reactor trip breaker testing. The auxiliary contacts are inspected and maintained as necessary during each refueling outage. The number of RTB cycles experienced will increase slightly in a longer fuel cycle, but will remain well below the vendor recommended duty for these breakers. Maintenance of the RTBs is discussed above for Functional Units 1 and 24 of Table 4.3-1.

Industry Experience

Industry experience and generic NRC communications were reviewed for the equipment used for each of the nine TADOTs. Issues concerning equipment operability have been addressed and appropriate testing, modifications, and programs are in place.

Summary

The surveillance, maintenance, and operating history of the specified equipment tested by these nine TADOTs support the conclusion that the effect on safety of extending the surveillance intervals is small. There are no recurring surveillance or maintenance problems. No time-dependent failure history is evident for any component. The preventive maintenance programs for the breakers and MSIVs have been reviewed and determined to support extension of the maintenance intervals.

PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes to the Table 4.3-1 Functional Units 1, 18, 19 and 24, and Table 4.3-2 Functional Units 1.a, 3.a.1), 3.b.1), 4.a and 8.c extend the frequency for the TADOT surveillances from "R", at least once per 18 months, to "R24", at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the testing is conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the specified components indicates they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the specified components will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval

does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

Evaluation of historical surveillance and maintenance data indicates there have been few problems with the specified components. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 14 -- TECHNICAL SPECIFICATION 4.4.3.3
REACTOR COOLANT SYSTEM - PRESSURIZER,
TRANSFER PRESSURIZER HEATERS TO EMERGENCY POWER SUPPLY

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 3/4.4.3, "Pressurizer," as follows:

> TS 4.4.3.3, regarding transfer of pressurizer heaters from normal to emergency power supply and energize the heaters, would be revised to change the surveillance frequency from at least once per 18 months to at least once each REFUELING INTERVAL.

The proposed change is provided in the marked-up copy of TS page 3/4 4-9 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

Four groups of pressurizer heaters assist in maintaining the water in the pressurizer at saturation temperature and maintaining a constant operating pressure. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the reactor coolant system (RCS) and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant.

The heater groups are normally powered from circuit breakers on the non-vital 480 V busses. Two of the heater groups have emergency backup power available in the event of a loss of offsite power, supplied from separate circuit breakers on the vital 480 V busses. Operator action is required to manually transfer the heater power supply to the emergency backup source. If the heater groups are aligned to vital power, they will be automatically shed from the vital 480 V busses by a safety injection (SI) signal since they are not Class 1E loads. Operator action would be required to re-energize the heaters in this case.

TS 4.4.3.3 requires the emergency power supply for these two groups of heaters be demonstrated operable at least once per 18 months by transferring power from the normal to the emergency power supply and energizing the heaters. The basis for this requirement is given in NUREG-0737, Section II.E.3.1. The emergency power supply is required to enhance the capability of the plant to control RCS pressure and establish and maintain

natural circulation in Mode 3 (Hot Standby) with loss of offsite power. The safety analysis conservatively assumes the pressurizer heaters are unavailable for natural circulation cooldown. Therefore, cooldown capability is confirmed assuming a complete loss of all pressurizer heaters.

C. SAFETY EVALUATION

The power supply transfer from normal to emergency backup power and energization of pressurizer heater groups 2 and 3 on each unit are verified quarterly during TS 4.3.2.1 required slave relay testing. The slave relay tests verify automatic shedding of the heaters from the vital busses in the event of an SI actuation. To verify the load shedding feature, the pressurizer heaters must be transferred from normal non-vital power to the vital power supplies and energized, incidentally satisfying the requirements of TS 4.4.3.3. At the completion of testing, they are returned to normal non-vital power.

PG&E submitted LAR 94-11, "Revision of Technical Specification 3/4.3.2 - Slave Relay Test Frequency Relaxation," (PG&E Letter DCL-94-254, dated November 14, 1994) to extend the surveillance interval for slave relay testing from quarterly to refueling frequency. Upon issuance of the amendments, the pressurizer heaters surveillance will change to refueling frequency, satisfying the requirements of TS 4.4.3.3 and 3/4.3.2.1.

Failure of a heater to transfer and energize may be due to problems in the individual pressurizer heater elements, the normal or emergency backup 480 V circuit breakers, or the manual transfer switch. Failures of these devices may be time-dependent.

TS 4.4.3.2 requires verification that heater group capacity is greater than 150 kW at least once per 92 days. This surveillance confirms that the pressurizer heaters provide sufficient heating capacity independent of refueling outage length. Each of the pressurizer heater groups with emergency power transfer capability normally provides 300 to 500 kW. Individual heater elements (approximately 23 kW per element) may be removed from service as necessary, leaving the heater group operable. Since there are many more elements than are required to meet the TS power requirement, immersion heater availability is not affected by refueling cycle length.

The 480 V normal supply circuit breakers for the pressurizer heaters are cycled manually by the operators during power changes, reactor trips, significant boration and dilution activities, and to increase pressurizer mixing prior to chemistry sampling. Due to these operational requirements, normal 480 V breaker failure would be noticed by the operators independent of refueling cycle length or surveillance testing.

The manual transfer switches and emergency backup supply breakers are only cycled as required by the TS 4.4.3.3 surveillance and by activities associated with TS 4.3.2.1 slave relay testing. These components receive no additional wear during normal operations. Consequently, no excessive mechanical stresses are placed on the components due to a potentially longer period between operations. Potential time-related degradation of these components is discussed under Maintenance History, below.

Operating History

A review of the operating history of the Diablo Canyon pressurizer heaters was completed. No instances of inadequate availability of pressurizer heaters were noted.

Past events resulting in natural circulation cooldown were reviewed. In each case, either power was restored before pressurizer heaters were required to be transferred, or normal power remained available to the pressurizer heaters. No events required pressurizer heaters to be transferred to emergency backup power.

Surveillance History

Data from 180 quarterly surveillance tests (over 40 tests for each of the four heater groups with transfer capability) were reviewed. The tests cover the past 10 years of operation on each unit. Six tests identified equipment problems.

Tests in October 1993 and September 1994 identified problems with emergency power supply 480 V breaker closure for Unit 1 heater group 3. The root cause was insufficient breaker linkage lubrication due to inadequate information provided for the obsolete breakers.

Three Unit 2 tests noted problems with racking operations on the non-vital normal power supply 480 V breakers in November 1986, July 1988, and January 1992. None of these failures affected the safety function of the pressurizer heaters' transfer to emergency power. Breakers were replaced and the surveillance procedures were revised to allow the breakers to be left racked in and open during the tests, thus eliminating this problem.

One Unit 1 test indicated a loading discrepancy in June 1994 caused by one phase of the transfer switch contacts failing to make up completely. The other two phases provided sufficient heater capability to pass the test acceptance criteria. The switch was cleaned and lubricated and passed subsequent surveillance tests. The other transfer switches were inspected; the other Unit 1

transfer switch was cleaned and lubricated, and the Unit 2 transfer switches were found to be satisfactory.

Maintenance History

A review of the maintenance history for the eight pressurizer heater breakers (four emergency and four normal) and four transfer switches was performed. These components are in the scope of the Diablo Canyon Reliability-Centered Maintenance Program and receive routine maintenance.

As noted above, the emergency breakers have experienced problems with racking operations and problems due to insufficient lubrication in the breaker linkage. The breakers are obsolete, and information, support, and spare parts are no longer available. The emergency supply breakers will be replaced with breakers similar to the normal supply breakers. Until the breakers are replaced, Diablo Canyon will continue quarterly testing of power supply heater transfer capability. The replacement breakers have a satisfactory performance history.

The normal supply breakers were originally of the same type as the emergency breakers. However, the normal breakers, which cycle much more frequently than the emergency breakers, were replaced between 1986 and 1990 with a more reliable model. The normal supply breakers have demonstrated an acceptable maintenance history and receive periodic maintenance on a refueling interval.

The transfer switches are maintained periodically. As noted in the Surveillance section, only one transfer switch problem was noted, in 1994, and was repaired.

The transfer switches and normal and emergency breakers may be maintained while the unit is at power, if required. Additionally, there are sufficient individual heater elements in each pressurizer heater group to allow elements to be removed from service if they fail. Consequently, there are no maintenance concerns with extension of the fuel cycle.

Industry Experience

Industry experience and generic NRC communications were reviewed, and no reports were noted that affect the maintenance or operation of the Diablo Canyon pressurizer heaters or their transfer schemes.

Summary

The surveillance, maintenance, and operating history of the Diablo Canyon pressurizer heater power supply transfer capability supports the conclusion that the effect on safety of extending the surveillance interval is small. In addition to

the TS 4.4.3.3 surveillance, other surveillance requirements and operational evolutions also demonstrate the continued operability of the pressurizer heaters.

No unsatisfactory time-related dependence was identified for operability of sufficient pressurizer heater elements, normal 480 V supply breakers, or transfer switches for the past 10 years. Quarterly surveillance testing of the power supply transfer capability will be continued until the obsolete emergency power supply breakers are replaced with new breakers. The new breakers are similar models to other plant breakers that have demonstrated satisfactory performance in the plant.

PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change to TS 4.4.3.3 extends the surveillance interval for verification of the transfer of the pressurizer heaters to emergency power supply from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the verifications are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the pressurizer heaters indicates that the heaters, their normal breakers, and the transfer switches will continue to perform satisfactorily with a longer surveillance interval. The emergency breakers will be replaced with new breakers that have demonstrated satisfactory performance elsewhere in the plant.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

The surveillance and maintenance history indicates that the pressurizer heaters will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

Evaluation of historical surveillance and maintenance data indicates there have been few problems with the pressurizer heaters, their normal breakers, and the transfer switches. The obsolete emergency breakers are scheduled for replacement with new, more reliable breakers. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition for operation, and there are no hardware changes that would impact existing safety analysis acceptance criteria.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 15 -- TECHNICAL SPECIFICATION 4.4.6.2.2a
OPERATIONAL LEAKAGE - PRESSURE ISOLATION VALVES

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 3/4.4.6.2, "Reactor Coolant System - Operational Leakage," as follows:

> TS 4.4.6.2.2a, regarding demonstration of operability of the reactor coolant system pressure isolation valves, would be revised to change the surveillance frequency from every refueling outage (18 months) to at least once each REFUELING INTERVAL.

The proposed change is provided in the marked-up copy of TS page 3/4 4-20 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

Reactor coolant system (RCS) pressure isolation valves (PIVs) are defined as any two normally closed valves in series within the reactor coolant pressure boundary, which separate the high pressure RCS from an attached low pressure system. During their lives, these valves may produce varying amounts of RCS leakage through either normal wear or mechanical deterioration. The RCS leakage limit of 1 gpm per valve given in TS 3.4.6.2f allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The leakage limit is sufficiently low to ensure early detection of possible in-series check valve failure. Leakage above the limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss-of-coolant accident (LOCA) and the loss of integrity of a fission product barrier.

At Diablo Canyon, PIVs are provided to isolate the RCS from the lower pressure residual heat removal (RHR) and safety injection (SI) systems. These valves are listed in Table 1, which corresponds to TS Table 3.4-1.

TABLE 1 & Table 3.4-1 REACTOR COOLANT SYSTEM PRESSURE ISOLATION VALVES	
Valve	Function
SI-8948 A/B/C/D	Accumulator, RHR and SI first off check valves from RCS cold legs
SI-8819 A/B/C/D	SI second off check valves from RCS cold legs
SI-8818 A/B/C/D	RHR second off check valve from RCS cold legs
SI-8956 A/B/C/D	Accumulator second off check valves from RCS cold legs
RHR-8701/8702	RHR suction isolation valve (MOVs)
SI-8949 A/B/C/D[1]	RHR and SI first off check valves from RCS hot legs
SI-8905 A/B/C/D[1]	SI second off check valves from RCS hot legs
RHR-8740 A/B[1]	RHR second off check valves from RCS hot legs
SI-8802 A/B[1]	SI to RCS hot legs isolation valves (MOVs)
RHR-8703[1]	RHR to RCS hot legs isolation valves (MOV)
[1] For flow paths with 3 pressure isolation valves in series, at least 2 of the 3 valves shall meet the requirements of TS 3.4.6.2f	

C. SAFETY EVALUATION

Leak testing on the PIVs is performed on a refueling frequency for all but three of the valves listed in Table 1. The exceptions are PIVs SI-8802A and -8802B, and RHR-8703, which are only required to be tested if work has been performed on them or if another valve in the isolation series has failed its leakage test. These three valves are the third off PIVs from the RCS on the hot leg injection flowpath.

Additional assurance of valve operability is provided by TS 4.4.6.2.2c. For this TS, the valves are leak tested within 24 hours following valve actuation due to automatic or manual action or flow through the valve. This TS applies to all of the check valves.

Also, prior to returning any of the valves to service following maintenance, repair, or replacement work on the valve, leakage testing is required by TS 4.4.6.2.2b.

Operating History

A review of the operating history of the specified PIVs was completed. There have always been two operable PIVs on each of the affected flow paths to or from the RCS in Modes 1 through 4, as required.

Surveillance History

Data from operational leakage verification tests for each of the specified valves on both units were reviewed. The tests covered every refueling outage for each unit. Three valves indicated leakage problems. None of the three valves affected the ability to maintain the integrity of the RCS with two PIVs during normal operation.

In October 1991, Unit 2 PIV RHR-8740A leaked by at 2.5 gpm. This valve is the RHR second off check valve from the RCS hot legs. Since SI-8949A and RHR-8703 were tested satisfactorily, RHR-8740A was not required to meet the leakage specification of TS 3.4.6.2f. The valve was disassembled the following refueling outage and found to have a small amount of dirt or corrosion product on the seating surface. The valve was reassembled and tested satisfactorily.

In November 1992, Unit 1 PIV SI-8905C leaked by at 1.9 gpm. This valve is the SI second off check valve from the RCS hot legs. Since SI-8949C and SI-8802B were tested satisfactorily, SI-8905C was not required to meet the leakage specification of TS 3.4.6.2f. The valve was disassembled the following refueling outage and found to have a pitted disc that only contacted 180° of the valve seat. The disc was replaced and the valve was reassembled and tested satisfactorily. No other valves of this model have experienced problems at Diablo Canyon.

In April 1993, Unit 2 PIV SI-8956C leaked by at 2 gpm. This valve is the accumulator second off check valve from the RCS cold leg. The valve was flushed by stroking the accumulator isolation valve with 100 psig in the accumulator and 50 psig in the RCS. SI-8956C was retested satisfactorily, with no leakage. The valve had tested satisfactorily at the beginning of the refueling outage. Although a conclusive root cause for the leakage is not known, it is probable that dirt and particles were trapped on the valve seat. Subsequent tests in April and October 1994 indicated no leakage.

Maintenance History

A review of the maintenance history for the last six years (from January 1990) for the PIVs was performed. All PIV check valves are in the check valve predictive maintenance and Inspection program. Those valves that are of a construction that can be opened for internal inspection receive periodic visual inspection. The inspection ensures that the internals are capable of full-stroke operation, have acceptable wear, will not bind in any way, have no disc-to-body contact, are capable of full-stroke operation, and that seat contact is satisfactory. Recently, non-intrusive testing has been used on some PIV check valves to verify full-opening capability and general condition of the valves.

Only one of the check valves was identified to have internal binding. In March 1990, Unit 2 PIV SI-2-8818B was noted to have its swing arm binding on the valve body. The swing arm was ground slightly to eliminate the contact area. The subsequent inspection in October 1994 found no problems and good seating contact.

The PIVs that are motor-operated valves (MOVs) receive routine preventive maintenance on their actuators each refueling outage. Maintenance consists of the following activities: internal and external visual inspection and cleaning, limit switch and main gear case grease quantity and quality evaluation, environmental qualification component integrity and condition inspection, and electrical equipment integrity and condition inspection.

Inspection and testing of the switchgear serving these MOVs are currently performed every 4.5 years. Visual inspection, cleaning, and breaker cycling are performed each refueling cycle.

Routine overhauls on MOVs are performed on a substantially longer frequency. The overhaul frequency is unique to each MOV and is based on environment, frequency of operation, prior history, and importance to plant operation. Within the last four cycles, all Diablo Canyon MOVs have received a complete refurbishment. Data gathered from this effort indicate that there is no appreciable degradation of grease or actuator components over several operating cycles for all but the few actuators operating in very warm environments. As a result of this study, overhaul frequencies were adjusted to between 4.5 and 10.5 years.

The maintenance review concluded that the frequency of the preventive maintenance procedures could be extended without adversely affecting the ability of the PIVs to perform their safety functions. The historical data indicate that all of the PIVs will continue to perform their safety functions over a longer fuel cycle.

Industry Experience

Industry experience and generic NRC communications were reviewed. Issues concerning PIV leakage have been addressed and appropriate testing and maintenance programs are in place.

Summary

The surveillance, maintenance, and operating history of the PIVs supports the conclusion that the effect on safety of extending the surveillance interval is small. The PIVs listed in Table 1 are located in flow paths that are not used during normal power operations. The length of the operating cycle has a minimal effect on these valves. There are no recurring surveillance or maintenance problems and no time-dependent failure history is evident.

PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change to TS 4.4.6.2.2a extends the surveillance interval for testing of the pressure isolation valves from at least once per refueling outage during startup to once per refueling interval during startup (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the leakage tests are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the pressure isolation valves indicates that they will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the pressure isolation valves will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function

performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

Evaluation of historical surveillance and maintenance data indicates there have been few problems with the pressure isolation valves. There is no evidence that in-service wear, which is time-dependent, has caused PIV leakage. Because the PIVs are not located on active flow paths during normal operation, there are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 16 -- TECHNICAL SPECIFICATION 4.5.2d
EMERGENCY AND CORE COOLING SYSTEMS - ECCS SUBSYSTEMS - T_{avg}
GREATER THAN OR EQUAL TO 350°F

CONTAINMENT RECIRCULATION SUMP INSPECTION

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 3/4.5.2, "ECCS Subsystems - T_{avg} Greater Than or Equal to 350°F," as follows:

> TS 4.5.2d, regarding containment recirculation sump inspection, would be revised to change the surveillance frequency from at least once per 18 months to at least once each REFUELING INTERVAL.

The proposed changes are noted in the marked-up copy of TS page 3/4 5-5 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

The function of the containment recirculation sump is to provide an unimpeded suction source for the residual heat removal (RHR) pumps during the recirculation phase following a loss-of-coolant accident (LOCA). The sump is located on the lowest floor elevation in the containment exclusive of the reactor vessel cavity. This arrangement maximizes the amount of water that will drain to the sump for use in the recirculation mode of safety injection.

The RHR suction line inlets are protected by two (inner and outer) debris interceptors composed of layers of wire mesh screen and steel grating. Because of the large surface areas of the debris interceptors, the RHR pumps are provided with adequate net positive suction head even if the outer screens are up to 95 percent blocked. The sump screens and internals are designed to prevent vortexing and air entrainment in the RHR pump suction lines in the event of partial screen blockage.

The outer debris interceptor surrounds the entire sump. Recirculation water will flow through the inclined and vertical sides of the outer interceptor. This side has an inner trash rack, a 1/2-inch coarse mesh screen, a second trash rack, an outer 3/16-inch fine mesh screen, and finally a grating to protect the fine screen from mechanical damage.

The inner debris interceptor covers the RHR suction line inlets. The inner interceptor is composed of a trash rack and 3/16-inch fine mesh screen. Both RHR pumps take suction inside the inner interceptor, with their suction inlets located 21 feet apart. The suction inlets are separated by a grating and fine mesh screen partition within the inner enclosure. The inner partition assures that the failure of one side of the inner screen assembly will not adversely affect the operability of the other side.

Sump materials were chosen to avoid degradation during periods of inactivity and power operation. The containment liner plate wall and concrete floors and walls of the sump are coated with a coating system qualified for the post-LOCA environment. This coating protects the liner plate from corrosion from normal and post-accident conditions. Since the sump may collect standing water during normal operation, the inner debris interceptor racks and suction divider were replaced with stainless steel components to reduce corrosion.

The TS surveillance requires visual inspection of the containment recirculation sump, verification that the suction inlets are not restricted, and that the sump components show no evidence of structural distress or corrosion. The sump inspection and related maintenance activities ensure that long term cooling will be available after a LOCA. The frequency of surveillance is based on the need to perform this inspection under the conditions that apply during a plant outage, on the need to have access to the location, and because of the potential for an unplanned transient if the surveillance were performed with the reactor at power.

C. SAFETY EVALUATION

The containment recirculation sump is usually inspected near the beginning of each refueling outage to identify items requiring maintenance, and again prior to containment closure near the end of each outage. The function of the inspections is to ensure that the sump will provide a sufficient suction source for the RHR pumps during the recirculation phase of a LOCA. Inadequate suction could occur if the sump screens, racks, or structure were physically degraded by corrosion or mechanical damage, allowing blockage of the suction inlets, or if foreign materials damaging to the RHR pumps or downstream components were admitted to the suction lines.

The surveillance test requires a thorough internal and external inspection of the sump for debris and foreign materials, evidence of structural distress, and corrosion. Structural distress includes visible signs of corrosion, damaged coatings, bent or ripped screens, bent racks, and broken or missing fasteners. Structural gaps are verified to be within design tolerances. The RHR pump suction lines are inspected for debris from their sump inlets up to the suction

isolation valves. Finally, a seismic inspection is performed at the sump outer screen to ensure all components associated with the sump are secured.

The surveillance test and associated maintenance activities ensure that degradation is detected and repaired long before it becomes significant or affects the sump structural integrity. Any problems found are documented on Action Requests and repaired under the work order system. The concrete and steel recirculation sumps are designed and constructed to ensure durability over the life of the plant. Visual inspections are expected to reveal only minor deterioration. The rate of deterioration is expected to be so slow that, over a period of years, sump integrity would not be affected.

Operating History

A review of the operational history of the Diablo Canyon Power Plant (DCPP) containment recirculation sumps identified no instances where the sumps would not have performed their safety function. Evaluations confirmed that sufficient suction would have been provided to the RHR pumps at all times.

Surveillance and Maintenance History

Data from 12 completed containment inspection surveillance tests were reviewed, covering all six refueling outages for each of the two DCPP units. Observations were identified on five of the 12 inspections concerning small gaps in the screens, paint chips and minor debris inside the sump, small areas of coating delamination, and corrosion on fasteners on the inner debris interceptors. The most recent inspection on each unit identified no deficiencies. In no instance was a problem identified that had the potential to accelerate and compromise structural or flowpath integrity in the proposed surveillance extension time.

In 1989, potential degradation of the sumps due to inadequate procedures and personnel error was reported by PG&E to the NRC in Licensee Event Report 1-89-014-01 (PG&E Letter DCL-90-018, dated January 19, 1990). Previous procedure revisions did not require the detailed and specific inspection process that is now used. In addition, the sump hatch had been periodically opened for sump level transmitter calibrations, potentially leading to common mode failure of the sump in the event of a LOCA.

PG&E has taken measures to prevent the recurrence of sump deficiencies, including both programmatic changes and physical modifications. These actions to prevent recurrence, including containment sump design modifications and procedure changes, were completed by July 1993 for both DCPP Units 1 and 2.

Programmatic changes included revision of the procedures for foreign material control inside containment and for containment sump inspection to specifically identify the attributes to be inspected inside the containment sump. The Design Criteria Memorandum covering the containment and the containment recirculation sump was completed and issued, clearly documenting the design basis of the sump. Preventive maintenance activities were established that require foreign material exclusion area covers to be installed on the sump suction piping on a routine basis following Mode 5 (Cold Shutdown) entry during refueling outages.

The containment sump modifications were enhancements to the sump to improve access for inspection and maintenance, to prevent damage to the screens during these activities, and to reduce corrosion rates that may degrade the sump screen structure. The operability and surveillance requirements in the TS for accident monitoring instrumentation, emergency core cooling system equipment, and containment spray equipment were not affected by any of these modifications.

Other sump maintenance includes periodic repair of the protective coatings applied over the containment liner and concrete walls and floor of the sump. Minor delaminations of coatings have been noted and repaired as required. The recirculation sump has been included in the containment coatings monitoring program performed each outage.

Industry Experience

Industry experience and generic NRC communications were reviewed. Containment recirculation sump maintenance and inspections have been the subject of several information notices and operational experience reports. The current sump inspection and foreign material control procedures address the concerns raised in the notices and reports.

Summary

The surveillance, maintenance, and operating histories of the Diablo Canyon containment recirculation sumps support the conclusion that the effect on safety of extending the surveillance interval is small.

No time-related dependence is evident for accumulation of debris or foreign materials, since the sump is not opened at power and the screens prevent debris from entering that might be capable of blocking the RHR flowpath. Corrosion and coating delamination damage are time-related. Affected areas would be replaced or repaired prior to degrading to the point where sump integrity could be challenged.

The time-related forms of sump degradation are long-term relative to the maximum refueling outage inspection interval of 30 months. PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change to TS 4.5.2d extends the surveillance interval for containment recirculation sump inspection from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the inspections are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating histories of the containment sump indicate that it will continue to perform satisfactorily with a longer surveillance interval. Although corrosion and coating delamination will degrade the sump with time, affected areas would be repaired or components replaced prior to degrading to the point where sump integrity would be challenged.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the containment recirculation sump will continue to effectively perform its design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

Evaluation of historical surveillance and maintenance data indicates that degradation mechanisms associated with the containment sump are manageable. Although corrosion and coating delamination rates are cycle-length dependent, they will not challenge sump integrity if inspected at the maximum refueling interval. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 17, 21, 23, 24, 25, 32

TECHNICAL SPECIFICATIONS
4.5.2e.1)
4.6.2.2c
4.6.3.2a
4.6.3.2b
4.6.3.2c
4.7.3.1b

AUTOMATIC VALVE ACTUATIONS

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the following automatic valve actuation TS to change the surveillance frequency from at least once per 18 months to at least once per REFUELING INTERVAL:

Item	Technical Specification
17.	TS 3/4.5.2, "ECCS Subsystems - Tavg Greater Than or Equal to 350°F," TS 4.5.2e.1), regarding verifying that each automatic valve in the emergency core cooling system (ECCS) subsystem flowpath actuates to its correct position on a safety injection (SI) actuation test signal;
21.	TS 4.6.2.2, "Spray Additive System," TS 4.6.2.2c, regarding verifying that each automatic valve in the flowpath actuates to its correct position on a containment spray (CS) actuation test signal;
23.	TS 3/4.6.3, "Containment Isolation Valves," TS 4.6.3.2a, regarding verifying that, on a Phase "A" isolation test signal, each Phase "A" isolation valve actuates to its isolation position;
24.	TS 3/4.6.3, "Containment Isolation Valves," TS 4.6.3.2b, regarding verifying that, on a Phase "B" isolation test signal, each Phase "B" isolation valve actuates to its isolation position;
25.	TS 3/4.6.3, "Containment Isolation Valves," TS 4.6.3.2c, regarding verifying that on a containment ventilation isolation (CVI) test signal, each CVI valve actuates to its isolation position;

32. TS 3/4.7.3, "Vital Component Cooling Water System," TS 4.7.3.1b, regarding verifying that each automatic valve servicing safety-related equipment actuates to its correct position on an SI or Phase "B" isolation test signal, as appropriate.

The proposed changes are provided in the marked-up copies of TS pages 3/4 5-5, 3/4 6-12, 3/4 6-15, and 3/4 7-11 in Attachment B. The proposed new TS pages are provided in Attachment C.

B. BACKGROUND

These TS verify that safety-related automatic valve actuations occur as assumed in the safety analysis. The actuation signals required for these surveillances are SI, CS, Phase "A" isolation, Phase "B" isolation, and CVI.

There are three automatic containment isolation signals produced during accident conditions. Containment Phase "A" isolation occurs upon the receipt of an SI signal. The Phase "A" isolation signal isolates non-essential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a containment pressure high-high signal and isolates the remaining process lines, except systems required for accident mitigation. An automatic CVI occurs upon receipt of an SI signal or a containment high radiation condition. The CVI valves help ensure that the containment atmosphere will be isolated from the environment after a design basis accident. The automatic actuation valves that fulfill the containment isolation functions consist of both motor-operated valves (MOVs) and air-operated valves (AOVs).

The valves that receive automatic containment isolation signals are shown in the Diablo Canyon Power Plant (DCPP) Units 1 and 2 Final Safety Analysis Report (FSAR) Update, Table 6.2-29. These valves are identified in the "Trip On" column by the actuation signals "T" for Phase A valves, "P" for Phase "B" valves, and Note 18 for CVI valves.

The remaining valves actuated by these TS serve functions other than containment isolation. With respect to valve operations, the SI signal initiates realignment of the boron injection flowpath. The CS signal aligns spray additive system valves on receipt of a containment high-high pressure signal. The Phase "B" signal also isolates the non-vital component cooling water (CCW) header from the vital headers, which is not a containment isolation function. The automatic valves that fulfill these functions are all MOVs, and the valves are listed in Table 1.

TABLE 1 -- SI, CS, and PHASE "B" AUTOMATIC ACTUATION VALVES			
Signal	Valve	Operation	Function
SI	CVCS-8107/8108	CLOSE	Isolate normal charging flowpath
SI	CVCS-LCV-112B/C	CLOSE	Isolate volume control tank
SI	SI-8805A/B	OPEN	RWST to charging pump suction
SI	SI-8803A/B	OPEN	Charging injection flowpath
SI	SI-8801A/B	OPEN	Charging injection flowpath
SI	8808A/B/C/D	OPEN	Accumulator discharge isolation[1]
CS	CS-8992	OPEN	Spray additive tank isolation[2]
CS	CS-8994A/B	OPEN	Spray additive to eductors
B	CCW-FCV-355	CLOSE	Receives Phase B signal, but is not a containment isolation valve

[1] These valves are required to be maintained in their safeguard position (open with power removed) per TS 3/4.5.1 in MODES 1, 2, and 3. They do not receive automatic actuation testing.

[2] The spray additive tank isolation valve is required to be maintained in its safeguards position (open with power removed) per TS 4.5.2.a in MODES 1 to 3.

C. SAFETY EVALUATION

Automatic valve actuation testing is performed on a refueling frequency, as a minimum. The test signals are generated via the solid state protection system (SSPS) slave relay test switches or during integrated system testing. In either case, the test signal actuates one or more SSPS slave relays, which actuate the individual valve control solenoids for AOVs or motor control circuits for MOVs. Each valve is verified to travel to its safeguards position.

Assurance of valve operability is provided by several other TS. TS 4.6.3.1 requires that each containment isolation valve be demonstrated operable prior to returning it to service after maintenance work. TS 4.6.3.3 requires that each containment isolation valve's isolation time shall be determined within its limit when tested pursuant to TS 4.0.5 on inservice testing (IST). The IST Program ensures the continued availability of the automatic actuation valves by verifying their mechanical operability. Approximately two-thirds of the valves are tested quarterly.

Further assurance of automatic actuation valve operability is provided by the automatic actuation logic testing of the SSPS performed on a staggered monthly frequency per TS 4.3.2.1, Table 4.3-2. This testing ensures that the correct automatic signals (SI, CS, Phases "A" and "B," and CVI) will be generated when required.

Valves that do not cause plant transients are also tested quarterly to meet TS 4.3.2 on slave relay testing. PG&E submitted LAR 94-11, "Revision of Technical Specification 3/4.3.2 - Slave Relay Test Frequency Relaxation," (PG&E Letter DCL-94-254, dated November 14, 1994) to extend the surveillance interval for slave relay testing from quarterly to refueling frequency. Upon issuance of the amendments, valve stroking associated with this surveillance will change to refueling frequency.

Operating History

A review of the operating history of the affected Diablo Canyon safety-related automatic actuation valves was completed. None of the valves failed to operate when actual SI, Phase "A" or CVI signals were received. No actual Phase "B" or CS signals have been generated at Diablo Canyon during plant operations.

Surveillance History

Diablo Canyon performs several different surveillance tests to satisfy the seven TS for automatic actuation valves. Typically, the TS are met by performing quarterly or refueling frequency slave relay tests, which provide an actuation test signal and verify that the valves actuate to their safeguards positions. The Phase "B" valves are tested during refueling frequency integrated system testing. Surveillance test results were reviewed for a minimum of the last four refueling cycles (approximately six years) for all affected valves on both units.

TS 4.5.2e.1) verifies that each automatic valve in the ECCS subsystem flowpath actuates to its correct position on an SI actuation test signal. In accordance with License Amendments 87 and 86, six of the 14 SI valves are tested at cold shutdown frequency since their actuation causes plant transients. The accumulator discharge valves are required to be open with power removed and do not receive automatic testing. The remaining valves are tested quarterly in accordance with TS 4.3.2.1 for slave relay testing.

One hundred thirty-one quarterly or refueling slave relay surveillance tests were reviewed covering the SI valves listed in Table 1 for both units. The review confirmed that there were no failures or problems in satisfying the TS with any of the SI automatic actuation valves in the last six years.

TS 4.6.2.2c verifies that each automatic valve in the spray additive flowpath actuates to its correct position on a CS actuation test signal. There are three CS valves per unit surveyed for this TS. These valves are only tested on a refueling frequency because their actuation could cause sodium hydroxide injection into containment.

Eight refueling slave relay surveillance tests were reviewed covering the spray additive valves for both units. The review confirmed that there were no failures or problems in satisfying the TS with any of the spray additive automatic actuation valves in the last six years.

TS 4.6.3.2a verifies that on a Phase "A" isolation test signal, each Phase "A" isolation valve actuates to its isolation position. Most of the Phase "A" isolation valves are stroked quarterly in accordance with TS 4.3.2.1 slave relay testing and the IST Program. A few valves cannot be stroked at power without causing equipment transients and are tested only on refueling frequency.

Two hundred fourteen quarterly and eight refueling slave relay surveillance tests were reviewed covering the Phase "A" valves for both units. The review confirmed that there were no failures or problems in satisfying the TS with any of the Phase "A" automatic actuation valves in the last six years.

TS 4.6.3.2b verifies that on a Phase "B" isolation test signal, each Phase "B" isolation valve actuates to its isolation position. All of the Phase "B" containment isolation valves are located in the CCW system on the non-vital header (five valves per unit). These valves are tested on a refueling frequency since their actuation would affect essential process equipment.

Sixteen refueling slave relay surveillance tests were reviewed covering the Phase "B" valves on both units. The review confirmed that there were no failures or problems in satisfying the TS with any of the Phase "B" automatic actuation valves in the last ten years.

TS 4.6.3.2c verifies that on a CVI test signal, each CVI valve actuates to its isolation position. There are 10 valves surveyed for this TS on each unit. Six of the valves are operated at least once per quarter for slave relay testing. The other four valves are maintained closed in their safeguards position.

Fifty-seven quarterly and 21 refueling frequency slave relay surveillance tests were reviewed covering the CVI valves on both units. The review confirmed that there were no failures or problems in satisfying the TS with any of the CVI automatic actuation valves in the last ten years.

TS 4.7.3.1b verifies that each CCW automatic valve servicing safety-related equipment actuates to its correct position on an SI or Phase "B" isolation test

signal, as appropriate. There are no CCW valves actuated by an SI signal at Diablo Canyon. There is one CCW valve per unit that receives a Phase "B" actuation signal and services safety-related equipment. This valve is tested on a refueling frequency since its actuation isolates the non-vital header and would adversely affect essential process equipment.

This valve is tested with the other CCW Phase "B" valves for both units (see test review comments for TS 4.6.3.2b). No failures have occurred in 10 years.

MOV Preventive Maintenance

The SI, CS, Phase "B," and two of the Phase "A" valves are MOVs. On loss of power, the MOVs fail as-is. This is desirable for these valves, since failing them closed would cause a plant transient during normal operations or partial loss of safety function during an accident. Two valves powered by independent 480 V vital busses are provided for each function to ensure that a single failure will not prevent successful initiation or isolation.

Routine preventive maintenance performed each refueling outage on all MOV actuators consists of the following activities: internal and external visual inspection and cleaning, limit switch and main gear case grease quantity and quality evaluation, environmental qualification component integrity and condition inspection, and electrical equipment integrity and condition inspection. Inspection and testing of the switchgear serving these MOVs is performed every 4.5 years. Visual inspection, cleaning, and breaker cycling are performed each refueling cycle.

Routine overhauls on MOV actuators are performed on a substantially longer frequency. The overhaul frequency is unique to each MOV and is based on environment, frequency of operation, prior history, and importance to plant operation. Within the last four cycles, all Diablo Canyon MOVs have received a complete refurbishment. Data gathered from this effort indicate that these is no appreciable degradation of grease or actuator components over several operating cycles for all but the few actuators operating in very warm environments. As a result of this study, overhaul frequencies were adjusted to between 4.5 and 10.5 years. In addition to the overhauls, many MOVs were modified and tested as a result of Generic Letter 89-10.

AOV Preventive Maintenance

All of the specified AOVs are Phase "A" containment isolation valves. The safety function of these valves is to be able to close on receipt of an isolation signal. On loss of power, loss of air, or diaphragm failure the specified AOVs fail closed. The AOVs require substantially less maintenance than do the MOVs because of the simpler operating mechanism and fewer potential failure modes.

Routine preventive maintenance on the specified AOVs consists of diaphragm replacement on a schedule based on valve environment, importance to plant operation, prior history, vendor recommendations, and frequency of operation. Valve performance is monitored via the IST Program and refueling outage leak rate testing. Performance monitoring has provided sufficient information to allow detection of degrading AOVs before they fail.

Maintenance History

A review of the maintenance history for the last six years (through January 1990) for each of the 154 automatic actuation valves (77 per unit) was performed. Many of these valves may be maintained while the unit is at power, if required. All of the automatic actuation valves are in the scope of the Reliability-Centered Maintenance Program.

There is no historical evidence to indicate a degradation in performance that would render an MOV unable to perform its intended safety function. Only two valves experienced significant corrective maintenance activities associated with conditions where a valve could have failed to perform its automatic actuation safety function since January 1, 1990. The two failures were unrelated and are isolated occurrences.

TS 4.5.2e.1): There have been two failures of ECCS flowpath valves that actuate on an SI signal.

In 1990, Unit 1 SI-8805A failed to cycle on command from the control room due to a component that was improperly installed and had worn down. The actuator was overhauled and the valve has worked properly since.

In 1994, Unit 2 SI-8805A would not stroke electrically after being manually seated during maintenance. It was determined that the valve would have failed to operate if excessive manual seating force were applied due to extra gaskets installed in the actuator. The failure did not prevent the valve from stroking electrically when correctly seated manually. The valve was repaired and tested satisfactorily.

TS 4.6.2.2c: There have been no failures of the spray additive valves that actuate on a CS signal.

TS 4.6.3.2a: There have been no failures of the Phase "A" isolation valves.

TS 4.6.3.2b: There have been no failures of Phase "B" containment isolation valves located in the CCW system on the non-vital header.

TS 4.6.3.2c: There have been no failures of the CVI valves.

TS 4.7.3.1b: There have been no failures of the CCW valve that isolates the non-vital header from the vital headers on a Phase "B" signal.

Industry Experience

Industry experience and generic NRC communications were reviewed. Issues concerning safety-related valve operability have been addressed and appropriate testing, modifications, and programs put in place.

Summary

The surveillance, maintenance, and operating history of the Diablo Canyon automatic actuation valves supports the conclusion that the effect on safety of extending the surveillance interval is small. There are no recurring surveillance or maintenance problems. No time-dependent failure history is evident when valves that are stroked quarterly are compared to valves that are stroked only on a refueling frequency. The preventive maintenance programs for the valves have been reviewed, and determined to support extension of the maintenance intervals.

PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes to TS 4.5.2e.1), 4.6.2.2c, 4.6.3.2a, 4.6.3.2b, 4.6.3.2c, and 4.7.3.1b extend the surveillance interval for testing automatic valve actuation from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the testing is conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the automatic isolation valves indicates that they will continue to perform satisfactorily with a longer surveillance interval. There is no known

mechanism that would significantly degrade the performance of this equipment during normal plant operation over the proposed maximum surveillance interval.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the automatic actuation valves will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   Evaluation of historical surveillance and maintenance data indicates there have been few problems with the automatic actuation valves. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 18, 22, 30

TECHNICAL SPECIFICATIONS
4.5.2e.2
4.6.2.3b
4.7.1.2.1c

AUTOMATIC PUMP and FAN ACTUATIONS

A. DESCRIPTION OF CHANGE

These Technical Specification (TS) changes would revise the following automatic pump and containment fan cooler unit (CFCU) actuation surveillance requirements to change the surveillance frequency from at least once per 18 months to at least once per refueling interval.

Item	Technical Specification
18.	TS 4.5.2e.2), regarding verifying that each of the following pumps start automatically upon receipt of a safety injection (SI) actuation test signal: a) Centrifugal Charging pump (CCP) b) SI pump, and c) Residual Heat Removal (RHR) pump;
22.	TS 4.6.2.3b, regarding verifying that each CFCU starts automatically on an SI test signal;
30.	TS 4.7.1.2.1c, regarding verifying that each auxiliary feedwater (AFW) pump starts and valve opens automatically as designed upon receipt of an AFW actuation test signal.

The proposed changes are provided in the marked-up copies of TS pages 3/4 5-5, 3/4 6-14, and 3/4 7-5 in Attachment B. The proposed new TS pages are provided in Attachment C.

B. BACKGROUND

These TS verify that certain safety-related automatic pump starts occur as assumed in the safety analysis. The Engineered Safety Features Actuation

System (ESFAS) initiates necessary safety systems to protect against violating core design limits, mitigating accidents, and protecting the reactor coolant system (RCS) pressure boundary. The engineered safety feature (ESF) components covered in this evaluation are the emergency core cooling system (ECCS) pumps, the CFCUs, and the AFW pumps. The ESFAS initiation signals that satisfy these TS are shown in Table 1.

TABLE 1-- ESF PUMP ESFAS INITIATION SIGNALS	
COMPONENT	INITIATION SIGNAL
CCPs	SI
SI Pumps	SI
RHR Pumps	SI
CFCUs	SI
AFW Pumps, Motor-driven	SI Steam generator low-low level
AFW Pumps, Turbine-driven	Steam generator low-low level Loss of offsite power

ECCS Pumps

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after a design basis accident. Major components of the ECCS include two CCPs, two SI pumps, and two RHR pumps in each unit. These ECCS pumps are normally in a standby, non-operating mode. Following a design basis accident and subsequent depressurization of the RCS, these pumps are started on an SI signal.

The CCPs also receive a safety-related start signal when no ESFAS signal is present on an automatic bus transfer to the emergency diesel generator. The bus transfer is surveilled to satisfy sections of Electrical Power Systems TS 4.8.1.1.1 and 4.8.1.1.2.

CFCUs

The CFCUs have both normal and accident functions. The normal function of the CFCUs is to ensure that the containment air temperature is maintained within the TS limits. The accident function of the CFCUs is to ensure that adequate heat removal capacity is available. The CFCUs and containment spray system together limit post-accident pressure and temperature in containment to less than the design values.

There are five dual speed CFCUs that are provided with power from three independent vital buses. Component cooling water is supplied to the CFCU

cooling coils by two independent vital headers. This arrangement ensures that, with a single active failure, a minimum of two CFCUs will function as required.

During normal operation, three CFCUs are operating at high speed. In post-accident operation following an SI signal, the shutdown CFCUs receive time sequenced signals and start automatically in slow speed. The CFCUs that were running in high speed prior to the accident are automatically shifted to slow speed. Simulated or actual SI signals satisfy the TS surveillance requirement for refueling interval verification of automatic actuation of the CFCUs.

AFW Pumps

The AFW system ensures that the RCS can be cooled down to less than 350°F from normal operating conditions in the event of a total loss of off-site power. The system also automatically supplies feedwater to the steam generators (SGs) to remove decay heat from the RCS upon loss of the normal feedwater supply.

The AFW system consists of three independent AFW supply trains powered by diverse, independent sources. Two of the trains have 50 percent capacity motor-driven pumps. One train has a 100 percent capacity steam turbine-driven pump. The steam for the turbine-driven pump is supplied from two of the four main steam lines upstream of the main steam isolation valves. The two steam supply lines meet upstream of the turbine-driven AFW pump automatic steam supply flow control valve, FCV-95. The turbine-driven pump is started automatically by the opening of FCV-95.

The motor-driven pumps actuate automatically on the ESFAS signals of SI and SG water level low-low (2 of 3 sensors in any one SG). Additionally, the pumps receive a safety-related start signal when no ESFAS signal is present on bus transfer to emergency diesel generator. The bus transfer is surveilled to satisfy sections of Electrical Power Systems TS 4.8.1.1.1 and 4.8.1.1.2. Finally, the pumps receive nonsafety-related start signals from loss of both main feedwater pumps and the Anticipated Transients Without Scram Mitigation System Actuation Circuitry (AMSAC). The nonsafety-related signals are not required to satisfy the refueling interval TS surveillance requirement.

The turbine-driven AFW pump is started by the ESFAS signals of SG water level low-low (2 of 3 sensors in any two SGs) and loss of offsite power (12 kV bus undervoltage). Additionally, FCV-95 receives a nonsafety-related start signal from AMSAC. The nonsafety-related signal is not required to satisfy the refueling interval TS surveillance requirement.

C. SAFETY EVALUATION

The components that function to generate ESFAS pump and fan automatic starts are the solid state protection system (SSPS) actuation logic and relays, the ESF timers, the 4 kV breakers, and the pumps and fans. Test signals actuate SSPS slave relays, which actuate discrete ESF timers, which actuate the individual pumps or CFCUs.

The components required to generate a turbine-driven AFW pump start are SSPS actuation logic and relays, a steam supply, FCV-95, and the turbine-driven AFW pump. The test signals actuate SSPS slave relays, which actuate FCV-95 to stroke open. If the steam supply lines are in their normal operating configuration and steam is available, FCV-95 opens and admits steam to the turbine-drive AFW pump. The pump accelerates to its working speed and remains available until the steam supply is isolated.

All of the ESFAS pump and fan automatic starts and the automatic opening of FCV-95 are currently tested quarterly to meet TS 4.3.2.1 on slave relay testing. PG&E submitted License Amendment Request 94-11, "Revision of Technical Specification 3/4.3.2 - Slave Relay Test Frequency Relaxation," (PG&E Letter DCL-94-254, dated November 14, 1994) to extend the surveillance interval for slave relay testing from quarterly to refueling frequency. Upon issuance of the amendments, actuations associated with this surveillance may change to refueling frequency.

Assurance of pump operability is provided by TS 4.5.2f (ECCS pumps) and TS 4.7.1.2.1b (AFW pumps). Each of these TS require a pump test pursuant to TS 4.0.5 on a quarterly frequency. The Inservice Test Program ensures the continued availability of the pumps by verifying their mechanical operability.

Assurance of CFCU operability is provided by TS 4.6.2.3a. This TS requires that each CFCU be demonstrated operable every 31 days by starting and running the CFCU for at least 15 minutes, by verifying the cooling water flow rate, and by verifying that each CFCU starts on low speed.

Assurance of automatic actuation operability is provided by the automatic actuation logic testing of the SSPS performed on a staggered monthly frequency per TS 4.3.2.1. This testing ensures that the correct automatic signals will be generated when required.

Operating History

A review of the operating history back to January 1990 for the specified pumps and CFCUs was completed. None of the pumps or CFCUs failed to operate as required when actual ESFAS signals were received.

Surveillance History

Diablo Canyon performs several different surveillance tests to satisfy the requirements of the three TS for automatic actuation of the pumps and CFCUs. Typically, the TS are met by performing quarterly or refueling frequency slave relay tests, which provide an actuation test signal and verify that the components actuate to their safeguards positions. Surveillance test results were reviewed for a minimum of the last four refueling cycles (approximately 6 years) for the specified pumps and CFCUs on both units.

TS 4.5.2e.2 verifies that each ECCS pump starts automatically upon receipt of an SI test signal.

Quarterly slave relay surveillance tests dating back to November 1989 were reviewed, covering all of the ECCS pump actuations for both units. The review indicated that there were two failures during this period, both caused by 4 kV breakers failing to close on demand.

Unit 1 SI Pump 1-2 failed to start in March 1991 when its breaker tripped. The breaker was replaced with a spare and the actuation test was successfully completed. The root cause of the failure was determined to be a combination of tolerances in parts dimensions and allowable adjustments to that particular breaker that caused the breaker to trip free. No other similar breakers have exhibited this problem. After lengthy investigation, the breaker with the trip problem was retired from service at Diablo Canyon.

Unit 1 RHR Pump 1-1 failed to start in January 1995 when its breaker would not close. The breaker was replaced with a spare and the actuation test was successfully completed. The root cause of the failure was determined to be either closing spring motor limit switch misadjustment or excess plastic injection mold flashing present in the contact area. The root cause could not be conclusively determined since the limit switch contacts melted and destroyed the evidence. All breakers on both units that could be required to open, recharge their springs, and close on a safety-related signal were inspected. Minor adjustments were made on seven breakers and one breaker had a limit switch replaced. No similar failures occurred either before or since this event. No maintenance procedure changes were required.

TS 4.6.2.3b verifies that each CFCU starts automatically on slow speed on an SI test signal.

Quarterly slave relay surveillance tests were reviewed covering the CFCU starts for both units back to 1990. The review confirmed that there were no failures or problems with satisfying the TS with any of the CFCUs during this period.

TS 4.7.1.2.1c verifies that the motor-driven AFW pumps start automatically and each steam isolation valve (FCV-95) opens and the steam-driven pump starts automatically upon receipt of an AFW actuation test signal. The motor-driven AFW pumps are currently surveilled quarterly on a staggered basis (one pump tested each month). The automatic start of the turbine-driven pump is surveilled on a refueling frequency. In addition, the automatic ESFAS actuations of FCV-95 are surveilled quarterly. For the quarterly test, the steam supply lines are isolated upstream of FCV-95 to reduce the starting demands on the turbine-driven pump.

Quarterly slave relay tests were reviewed covering the motor-driven AFW pump starts and FCV-95 static valve strokes for both units back to 1990. Refueling surveillance tests were reviewed covering the automatic actuation of the turbine-driven AFW pumps in both units back to the first refueling outages (7 tests per unit). The review confirmed that there were no failures or problems with satisfying the TS with any of the motor-driven AFW pumps. Two failures affected the turbine-driven AFW pumps.

On Unit 1 in September 1991, a quarterly test failed when FCV-95 failed to open. This failure was similar to previous failures that occurred during functional stroke tests on the same valve in 1989 and 1990. The earlier failures were attributed to thermal binding caused by dissimilar valve seat and wedge materials, leading to a wedge replacement in early 1991. After the September 1991 failure, the valve was instrumented and placed on an accelerated test frequency. After an additional failure generated new data, the motor and pinion gear were replaced in early 1992, greatly increasing the opening force. All tests following this modification have been successful, in all line configurations (cold and hot steam starts, static tests, etc.).

On Unit 2 in April 1990, a refueling test failed when the turbine-driven pump tripped on overspeed during an automatic pump start actuation test. Subsequent testing and investigation indicated that the overspeed event was caused by water accumulation in the main steam lines behind the main steam isolation valves. When FCV-95 opened, slugs of water reached the turbine. The turbine governor is not designed to respond to slugs of water entering the turbine; the governor responded to the temporary turbine speed decrease by opening steam supply throttle valves, which ultimately caused the pump to trip on overspeed. Additional steam traps with drains to the main condenser were added in both units to prevent recurrence. Subsequent operational experience indicate that the modifications have resolved the issue.

Maintenance History

A review of the maintenance history for the last six years for the ECCS, AFW pumps (and FCV-95), and CFCUs was performed. If required, all of the pumps may be maintained or replaced while the unit is at power. Additionally, most CFCU maintenance may be performed at power. All of the pumps and CFCUs are within the scope of the Reliability-Centered Maintenance and Predictive Maintenance Programs.

Routine preventive maintenance on the pumps, CFCUs and their motors consists of cleaning and maintain oil levels, visual inspection, vibration monitoring, fan bearing clearance checks for CFCUs, electrical component maintenance activities, and environmental qualification program maintenance activities. On a much longer frequency, motor overhauls are performed. There is no indication that the proposed fuel cycle extension would cause deterioration in the lubricants or physical or electrical condition of the pumps, CFCUs or their motors. Many of the routine inspection activities are performed at intervals shorter than 18 months and some are performed at longer intervals; none of these inspection activities would be affected by the change in fuel cycle length. The review concluded that the frequency of the preventive maintenance procedures could be extended in those cases where the period of maintenance is now 18 months, without an adverse effect on the operability of the components.

Significant corrective maintenance activities occurring after January 1, 1990, and associated with conditions where a pump or CFCU could have failed to perform its automatic actuation safety function are as follows.

TS 4.5.2e.2: There have been no failures of the ECCS pumps, timers, breakers, or SSPS actuation logic or relays that would have prevented them from starting on an automatic actuation signal.

TS 4.6.2.3b: The maintenance history of the CFCUs from January 1990 to the present indicates four problems where the CFCUs did not operate properly during normal high speed operation. Two of the four events would have affected the ability of the CFCUs to start and run in low speed after an accident. Three of the problems were found and resolved during normal CFCU operation and one was found after a reactor trip. All four events were random, unrelated failures, as discussed below. Since at least three of the five CFCUs run at all times during normal operations, most problems are detectable upon occurrence. All of these problems would be repairable at power.

- Unit 2 CFCU 2-2 tripped three times in March and April 1990 during a refueling outage due to a failing control transformer. The transformer was replaced and the CFCU was tested satisfactorily. This was an isolated

failure occurrence, as there are hundreds of similar control transformers in the plant with very few failures. This failure would have prevented the CFCU from starting after an accident.

- Unit 1 CFCU 1-5 tripped once in October 1992 due to a maintenance error during the Unit 1 fifth refueling outage in which the high and low speed thermal overload devices were reversed. The error was identified during the outage and fixed; therefore, the error would not have prevented the CFCU from running in low speed after an accident.

- Unit 1 CFCU 1-5 failed to start after a reactor trip (with no SI) in December 1994 due to the random failure of a microswitch on a timing relay. The timing relay was replaced and the CFCU was tested satisfactorily. The remaining CFCUs were inspected and no other microswitch problems were found. The relay failure would have prevented the CFCU from starting in slow speed after an accident.

- Unit 1 CFCU 1-3 tripped while running on high speed with a containment pressure of 0.7 psig in September 1995. The trip was attributed to high fan load caused by the denser containment atmosphere combined with a thermal overload device that was tripping at the lower end of its setting range. The high speed trip did not affect the ability of the CFCU to start and run in low speed after an accident.

TS 4.7.1.2.1c: There have been no failures of the motor-driven AFW pumps, timers, breakers, or SSPS actuation logic or relays that would have prevented them from starting on an automatic actuation signal. Regarding the turbine-driven AFW pumps, the only significant corrective maintenance activities have been concerning FCV-95, which have been discussed previously in the Surveillance History section.

Industry Experience

Industry experience and generic NRC communications were reviewed. The issues discussed in NRC Information Notice 94-76 concerning CCP shaft failures and internal cladding degradation have been reviewed and investigatory actions completed. There have been no such failures at Diablo Canyon, but spare parts have been confirmed to be in place should either failure occur. CCP history indicated that one pump had a potential shaft failure initiating event; that CCP was replaced in the 1995 Unit 1 seventh refueling outage.

Industry experience and NRC generic communications on CFCUs were reviewed and no reports were noted that affect the maintenance or operation of the Diablo Canyon CFCUs. Industry information on turbine-driven AFW pump overspeed events has been reviewed on an ongoing basis for impact on the

Diablo Canyon pumps. Maintenance and testing practices are in place to address these concerns.

Summary

The surveillance, maintenance, and operating histories of the Diablo Canyon automatic ESFAS actuations of the ECCS pumps, CFCUs, and AFW pumps support the conclusion that the effect on safety of extending the surveillance interval is small. There are no recurring surveillance or maintenance problems. Those problems that have occurred were identified during on-line testing or normal operations. None of the problems required waiting until a refueling outage to make repairs necessary to assure operability. The preventive maintenance programs for the pumps and CFCUs have been reviewed and determined to support extension of the maintenance intervals.

PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes to TS 4.5.2e.2, 4.6.2.3b, and 4.7.1.2.1c extend the surveillance interval for testing the ESFAS automatic actuations of the ECCS and AFW pumps and the CFCUs from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the refueling tests are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the automatic actuation circuitry of the ECCS and AFW pumps and CFCUs indicates that they will continue to perform satisfactorily with a longer surveillance interval. The occasional problems that occur are detected via on-line testing and normal operation. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the automatic actuation circuitry of the ECCS and AFW pumps and CFCUs will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   Evaluation of historical surveillance and maintenance data indicates there have been few problems with the automatic actuation circuitry of the ECCS and AFW pumps and CFCUs. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 19 -- TECHNICAL SPECIFICATION 4.5.2g.2)
EMERGENCY CORE COOLING SYSTEMS - ECCS SUBSYSTEMS - T_{avg} GREATER THAN OR EQUAL TO 350°F, ECCS THROTTLE VALVE POSITION STOP VERIFICATION

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 3/4.5.2, "ECCS Subsystems - T_{avg} Greater Than or Equal to 350°F," as follows:

> TS 4.5.2g.2), regarding verification of the correct position of the position stops for emergency core cooling system (ECCS) throttle valves, would be revised to change the surveillance frequency from at least once per 18 months to at least once each REFUELING INTERVAL.

The proposed change is provided in the marked-up copy of TS page 3/4 5-6 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

The function of the ECCS throttle valves is to ensure that sufficient emergency core cooling is provided following a loss-of-coolant accident (LOCA). The eight valves are located in containment, one in each of the four charging injection and four safety injection (SI) lines to the reactor coolant system (RCS) cold legs. The affected valves are listed in Table 1.

Table 1: ECCS Throttle Valves	
Charging Injection Throttle Valves	Safety Injection Throttle Valves
8810 A	8822 A
8810 B	8822 B
8810 C	8822 C
8810 D	8822 D

The eight valves are locked in position during ECCS flow balance testing after centrifugal charging pump and SI pump flows are set. The locked throttle valves ensure that pump runout limits, maximum and minimum injection flow requirements, and line-to-line balance requirements are achieved.

The ECCS throttle valves are designed with an integral mechanical stem lock in lieu of a valve operating handle. The lock is loosened in order to set valve position, and then tightened to lock the valve into place. Charging injection and

SI flows are reverified after the valves are locked in their final positions, ensuring that the locking process does not disturb valve position. Once a valve is locked, it cannot move in either the closed or open directions. Lockwires are fastened through loops attached to the valve yoke, stem lock, and lock cover. Finally, numbered plastic valve seals are installed through the permanent loops together with the lockwires.

To change the position of a throttle valve, the plastic valve seal must first be broken, then the lockwire removed using tools, and finally, wrenches used to unlock the valve and change its position.

C. SAFETY EVALUATION

Position verification of the mechanical stops on the eight charging and SI ECCS throttle valves is completed each refueling outage. The surveillance is completed by checking that each valve seal between the valve yoke, stem lock, and cover nut is intact, and verifying that the unique seal identification number has not changed from the previous test, unless this is the first test after flow balancing was performed. The verification is performed at the end, as well as usually at the beginning, of each refueling outage.

If a valve seal is found not intact, the lockwire is examined to ensure that it is intact and fastened to the valve yoke, stem lock, and lock cover. The valve physical condition, maintenance history, and work in progress in the vicinity of the valve are examined to determine whether the valve was disturbed. If this evaluation is inconclusive, then the ECCS flow balance test would be performed to verify that ECCS flows are unchanged from the previous performance.

The function of the ECCS throttle valve mechanical stop position verification is to ensure that the throttle valves remain correctly set so that the accident analysis assumptions concerning system resistance and design flows are met. Due to the mechanical lock design, valve position change could result only from breakage or removal of the mechanical stem lock. Lock removal or breakage is detectable through visual examination of the valve locking mechanism and finding non-intact seals and broken or removed lockwires.

Operating History

During power operation, the charging injection and SI lines have no flow and are not pressurized. The valves are located inside containment and are unlikely to be disturbed. The two times these lines may experience flow conditions are either during flow balance testing performed while the reactor is shutdown or after an SI actuation when the RCS pressure drops low enough for the ECCS pumps to inject forward into the RCS.

A review of the operational history of the Diablo Canyon ECCS charging injection and SI throttle valves identified no instances of mechanical position stop failure or stem locks found in incorrect positions. There have been no inadvertent adjustments of the throttle valves or their mechanical stops during periods of power operation.

Surveillance History

Data from 12 completed position verification tests for the 16 valves (eight per unit) were reviewed. The tests cover the six refueling outages for each valve. Three of the tests (Unit 1 in April 1988; and Unit 2 in October 1988 and September 1991) indicated that one or more plastic valve seals were broken. However, in each case sufficient evidence existed to provide positive indication that the valves otherwise had not been disturbed.

To reduce recurrence of broken seals, additional valve seal identification and procedural controls were added to more clearly identify the engineering controlled valves. Lamacoids were attached to the throttle valves via the plastic valve seals, stating that the seals should not be disturbed and that the system engineer should be contacted for further information. Since these corrective actions were put in place (Unit 2 in October 1991, Unit 1 in October 1992) there have been no further broken seals in the subsequent four refueling outages.

Maintenance History

A review of the maintenance history for the 16 ECCS throttle valves identified no instances of repair or replacement of the valve mechanical position stops. Maintenance performed on the valves has been limited to packing replacement and adjustment. After each maintenance activity, the valve was returned to its required throttle position. The valves are identified in the Diablo Canyon Reliability-Centered Maintenance Program, but are not subject to any time-dependent maintenance activities.

Industry Experience

Industry experience and generic NRC communications were reviewed, and no reports were noted that affect the ability to lock the ECCS throttle valves in their accident positions.

Summary

The surveillance, maintenance, and operational histories of the Diablo Canyon ECCS throttle valve mechanical position stops support the conclusion that there is no effect on safety of extending the surveillance interval. During normal

power operations, the throttle valves and locks experience no cycling that could contribute to a lock failure based on valve wear. There have been no broken stops and, while several broken plastic seals have been found, the lockwires fastening the stem locks to the valve yokes have always been found intact. PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change to TS 4.5.2g.2) extends the surveillance interval for verification of the correct position of the ECCS throttle valve position stops from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the verifications are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the throttle valve position stops indicates that the stops and associated mechanical stem locks will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of the stops or mechanical locks during normal plant operation.

   Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the throttle valve position stops and mechanical stem locks will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

Evaluation of historical surveillance and maintenance data indicates there have been no problems with the throttle valve position stops and few problems with the mechanical stem locks. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition for operation, and there are no hardware changes that would impact existing safety analysis acceptance criteria.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 20 -- TECHNICAL SPECIFICATION 4.6.1.7.3
CONTAINMENT SYSTEMS - CONTAINMENT VENTILATION SYSTEM,
VACUUM/PRESSURE RELIEF ISOLATION VALVE POSITION BLOCKS

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 3/4.6.1.7, "Containment Ventilation System," as follows:

> TS 4.6.1.7.3, regarding vacuum/pressure relief isolation valve position block, would be revised to change the surveillance frequency from at least once per 18 months to at least once each REFUELING INTERVAL.

The proposed change is provided in the marked-up copy of TS page 3/4 6-10 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

The containment pressure and vacuum relief system operates (1) to assure that the containment pressure limits for normal operation, as assumed in the accident analysis, are not exceeded, and (2) to maintain the air in containment within habitability limits. The containment pressure and vacuum relief system consists of a single 12-inch containment penetration line, which serves either to allow air flow into or out of the containment. Outside of containment, the line branches to either the vacuum or pressure relief pathways. This line has one inboard isolation valve (FCV-662) and two parallel outboard isolation valves (FCV-663 and FCV-664), all of which are butterfly valves. All three valves are closed by a containment ventilation isolation signal during accident conditions.

TS 3.6.1.7 requires the containment pressure/vacuum relief line valves to be blocked to prevent their opening beyond 50° (90° is fully open). The basis for this requirement is given in Section 6.2 of NUREG-0800, "Standard Review Plan." Butterfly valves used for containment purging and venting operations were identified as being potentially unable to close against the increasing differential pressure and resulting dynamic loading of a design basis loss-of-coolant accident (LOCA) (NUREG-0737, Item II.E.4.2). The immediate resolution was to limit the angle of opening of the valves to ensure that the valve operators would function properly after a LOCA.

At Diablo Canyon, the blocking mechanism used on each of the three valves is a permanently installed stop sleeve made of steel pipe. The stop sleeve is

mounted on the actuator piston rod inside the actuator cylinder and cannot be removed without disassembling the actuator. The non-adjustable sleeve physically prevents the actuator piston from traveling past the 50° open position. Since blocking is accomplished by a solid piston stop sleeve, there is nothing to slip or go out of adjustment.

PG&E Letter DCL 88-176, dated July 5, 1988, transmitted to the NRC the valves' qualification of isolation capability and noted PG&E's decision to maintain FCV-662, FCV-663, and FCV-664 blocked to prevent opening beyond 50° for the life of the plant. The evaluation for the valves' operability during a design basis event was performed assuming that the valves were blocked at 50° with a maximum closure time of 5 seconds, in accordance with Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations." The NRC accepted this analysis in the Safety Evaluation for License Amendments 31 and 30, issued August 29, 1988.

C. SAFETY EVALUATION

The verification of vacuum/pressure relief isolation valve position blocking for FCV-662, FCV-663, and FCV-664 is completed each refueling outage as part of the exercising and position verification tests used to verify valve operability. This testing satisfies the TS position blocking and stroke time requirements, as well as ASME Section XI test requirements for local observation of valve stroking every two years. The field verification ensures proper operation of the mechanical stop through observation of the valve and actuator position. Valve stroke verification is also completed after any maintenance on valve or actuator that could affect operability.

The function of the position block verification test is to ensure that the ventilation system valves will close during a design basis accident and meet the 10 CFR 100 offsite dose limits. Due to the mechanical stop design, a change in the allowed open position of any of the three FCVs could result only from breakage of the stop or improper reassembly of the actuator following maintenance. Stop breakage is unrelated to maintenance interval, and would occur only if there were defects in the stop. Stop removal, breakage, or improper reassembly are detectable through post-maintenance testing.

Operational History

A review of the operational history of the Diablo Canyon vacuum/pressure relief valve position blocks identified no instances of position block failure.

Surveillance History

Data from 79 completed valve exercising and position verification tests for the six valves (three per unit) were reviewed. The tests cover at least the six refueling outages for each valve, and in some instances cover pre-operational testing as well. All of the tests met the acceptance criteria for valve position blocking and stroke time.

Maintenance History

A review of the maintenance history for the six vacuum/pressure relief valves identified no instances of repair, replacement, or removal of the valve position block stop sleeves. The valves and actuators are covered by the Diablo Canyon Reliability-Centered Maintenance Program, and appropriate preventive maintenance is performed.

Industry Experience

Industry experience and generic NRC communications were reviewed, and no reports were noted that affect the maintenance or operation of the Diablo Canyon vacuum/pressure relief isolation valves.

Summary

The surveillance, maintenance, and operational history of the Diablo Canyon vacuum/pressure relief isolation valves supports the conclusion that the effect on safety of extending the surveillance interval is small. No time-related dependence is evident for operability of the valve position blocks for the past 10 years. PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change to TS 4.6.1.7.3 extends the surveillance interval for verification of the vacuum/pressure relief isolation valve position blocks from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

The increased surveillance interval does not alter the intent or method by which the verifications are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the vacuum/pressure relief isolation valve position blocks indicate that the block sleeves will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of the block sleeve during normal plant operation.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the vacuum/pressure relief isolation valve blocks will continue to effectively perform their design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   Evaluation of historical surveillance and maintenance data indicates there have been no problems with the vacuum/pressure relief isolation valve blocks. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition for operation, and there are no hardware changes that would impact existing safety analysis acceptance criteria.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEMS 26, 27, 28, 29 --TECHNICAL SPECIFICATION 4.6.4.2
CONTAINMENT SYSTEMS - ELECTRIC HYDROGEN RECOMBINERS

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 4.6.4.2, "Electric Hydrogen Recombiners," as follows:

> TS 4.6.4.2a., 4.6.4.2b.1), 4.6.4.2b.2), and 4.6.4.2b.3), regarding operability of electric hydrogen recombiners, would be revised to change the surveillance frequency from at least once per refueling interval (18 months) to at least once each REFUELING INTERVAL (24 months).

The proposed changes are provided in the marked-up copy of TS page 3/4 6-18 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

The safety-related function of the electric hydrogen recombiner system (EHRS) is to remove hydrogen gas that is generated in containment following a loss-of-coolant accident (LOCA). The EHRS heats a continuous flow of air-hydrogen mixture to a temperature sufficient for spontaneous recombination of the hydrogen with the oxygen in the air to form water. This is done to prevent the possibility of a post-accident hydrogen burn or explosion in containment that could impact safety-related equipment or containment integrity.

The EHRS consists of two manually controlled independent trains of natural convection, flameless, thermal reactor type recombiners powered from different vital busses. Each of the 100 percent capacity trains consists of the recombiner unit containing passive heater banks, a power supply panel containing the equipment for powering the heaters, and a control panel for the heaters. The recombiner units are located in containment and are environmentally qualified. The power supply and control panels are located outside containment in a non-harsh environment accessible to operators following an accident.

The EHRS does not require any instrumentation inside the containment for proper operation after a LOCA. Thermocouples are provided for convenience in testing; however, they are not necessary to ensure proper operation of the recombiner. Proper EHRS operation after an accident is ensured by measuring the amount of power supplied to the recombiner from the control panel. The temperature readout is a monitoring unit, rather than a control unit.

C. SAFETY EVALUATION

The functional testing, instruments and controls calibration, visual inspections and integrity verification of heater elements for the EHRS are performed each refueling outage. The TS 4.6.4.2a functional test was previously performed every six months. In accordance with GL 93-05, the functional test surveillance was changed to once each refueling interval with a basis of 18 months in License Amendments 102 and 101, issued July 25, 1995.

The recombiner units are mechanically passive, and are not subject to mechanical failure. Credible failures involve loss of power, internal flow blockage or missile impact. Because the system is normally de-energized and is maintained in standby condition, there are no accelerated time-dependent failure mechanisms such as heating or wear.

Operating History

A review of the operating history of the Diablo Canyon EHRS was completed. This system has never been required to operate on either unit. The only time the system has been operated is during functional testing.

Surveillance History

Diablo Canyon performs two refueling frequency surveillance tests that together satisfy the four refueling TS. In addition, before License Amendments 102 and 101 were issued to revise the functional test frequency to once per 18 months, a functional test was performed every 6 months. Test results were reviewed for each unit covering the previous four to five outages for the refueling tests and the last five years for the biannual functional tests. None of the test problems noted below would have prevented any of the EHRS units from fulfilling its safety function in the event of an accident.

TS 4.6.4.2a requires through functional testing that the minimum heater sheath temperature increases to greater than or equal to 700°F within 90 minutes. Upon reaching 700°F, the power setting is increased to maximum for 2 minutes and power is verified greater than or equal to 60 kW. A review of 36 biannual tests of the recombiners determined that there was one test failure and one indicator problem recorded in the last 5 years.

In 1993, EHRS 2-1 failed when it generated only 61 kW at the full power setting. The Diablo Canyon acceptance criterion is greater than or equal to 64 kW to account for possible instrument error. This criterion is conservative when compared to the TS requirement of 60 kW. The silicon-controlled rectifiers (SCRs) were not firing at full on and were adjusted. The EHRS

performed satisfactorily in subsequent testing. This failure would not have prevented successful operation of the EHRS in an accident, since the required temperature for hydrogen recombination is reached at a significantly lower power setting. In addition, the electronic components are located in the power cabinet and are accessible following an accident.

In 1992, an EHRS 1-2 temperature indicator failed and was replaced. The indicator is not required for proper functioning of the EHRS after an accident, and does not affect the safety function of the unit.

TS 4.6.4.2b.1) requires performance of a channel calibration of all recombiner instrumentation and control circuits. A review of 53 refueling frequency channel calibration tests covering the period from October 1986 through the last fuel cycle identified one test failure and one indicator replacement, both on EHRS 2-1 in May 1987.

In 1987, EHRS 2-1 failed due to an overly conservative acceptance criterion when the error between the wattmeter reading and the calculated full power value differed by 2.07 percent (acceptance criterion was 2 percent). The unit was recalibrated and tested satisfactorily. The acceptance criterion was subsequently revised to correctly incorporate the maximum potential instrument error term.

During the same outage, one temperature indicator on EHRS 2-1 was replaced when the required accuracy was not met. The indicator is not required for the proper functioning of the EHRS after an accident and does not affect the safety function of the unit.

TS 4.6.4.2b.2) requires verification through visual examination that there is no evidence of abnormal conditions within the recombiner enclosure (i.e., loose wiring or structural connections, deposits of foreign materials, etc.). A review of the visual inspections identified three minor discrepancies, none of which has recurred. In 1990, a small amount of gray powdery residue was found in the bottom of one recombiner and cleaned out. In 1990 and 1991, two wires were cut back and relugged after bare wire was noted. None of the items impacted operability of the recombiners or would have prevented them from performing their safety function.

TS 4.6.4.2b.3) requires verification of the integrity of heater electrical circuits by performing a resistance check following the functional test to ensure that each heater phase resistance to ground is greater than 10,000 ohms. A review of the tests identified two failures.

In late 1986, one heater element was found to be grounded on EHRS 1-2 and was determinated. This failure did not prevent the recombiner from being

operable at any time. There are sufficient remaining heater elements for the recombiner to perform its safety function and pass all surveillance requirements, so the element has not been replaced. In 1990, one element on EHRS 2-2 did not demonstrate sufficient resistance to ground due to an overly conservative test methodology. The methodology was changed to comply with the vendor's recommendation and no further problems have occurred.

Maintenance History

A review of the maintenance history for the four recombiners (two on each unit) was performed. Most of the maintenance activities on the EHRS units are performed as an integral part of the extensive surveillance testing. Maintenance on the EHRS has been limited to routine cleaning, visual inspection, and electrical component maintenance activities on a refueling frequency. The electrical cables and recombiner units inside containment are maintained as required by the environmental qualification program. The EHRS units are in the scope of the Reliability-Centered Maintenance Program.

The recombiner power and control cabinets may be maintained while the unit is at power or after an accident. Consequently, there are no maintenance concerns with extension of the fuel cycle for the components outside containment.

The recombiner units inside containment are passive heaters. The visual inspections and routine cleaning and maintenance activities ensure that no degradation is occurring that could prevent the EHRS from performing its safety function during a longer fuel cycle.

Industry Experience

Industry experience and generic NRC communications were reviewed, and no reports were noted that affect the maintenance or operation of the Diablo Canyon EHRS.

Summary

The surveillance, maintenance, and operating history of the Diablo Canyon EHRS supports the conclusion that the effect on safety of extending the surveillance interval is small. There are no recurring surveillance or maintenance problems. The recombiner units are passive and not subject to mechanical failures. The power and control cabinets are located outside containment in a mild environment and could be maintained after an accident if necessary.

PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed changes to TS 4.6.4.2a and 4.6.4.2b extend the surveillance interval for testing and inspection of the EHRS from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the tests and inspections are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the EHRS indicates that the recombiners will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of the EHRS during normal plant operation.

   Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the EHRS will continue to effectively perform its safety function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   Evaluation of historical surveillance and maintenance data indicates there have been few problems with the EHRS. There are no indications that potential problems would be cycle-length dependent. Therefore, increasing

the surveillance interval will have little, if any, impact on safety. There is no safety analysis impact since this change has no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that could impact existing safety analysis acceptance criteria.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

SAFETY EVALUATION

ITEM 31: TECHNICAL SPECIFICATION 4.7.1.6c
PLANT SYSTEMS
STEAM GENERATOR 10% ATMOSPHERIC DUMP VALVES

REMOTE MANUAL CONTROLS AND BACKUP AIR BOTTLES

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would revise TS 3/4.7.1.6, "Steam Generator 10% Atmospheric Dump Valves," as follows:

> TS 4.7.1.6c, regarding verification of the operation of the steam generator (SG) 10 percent atmospheric dump valves (ADV) remote manual controls and backup air bottles, would be revised to change the surveillance frequency from at least once per 18 months to at least once each REFUELING INTERVAL.

The proposed changes are provided in the marked-up copy of TS page 3/4 7-9a in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

The safety-related functions of the SG 10 percent ADVs are to serve as containment isolation valves and to allow cooldown of the primary plant following either a Hosgri earthquake or a steam generator tube rupture (SGTR) accident concurrent with loss of offsite power. To fulfill these functions, the design basis requirements for the ADVs are that they fail closed upon loss of air and be capable of manual operation. To meet the manual operation requirement, the ADVs are furnished with Class 1 seismically qualified backup air supplies (air bottles) with instrument Class 1E controls and power circuits providing manual remote control from the control room.

The 10 percent ADVs were originally purchased as design Class 1 valves for use in the nonsafety-related steam dump control system. In 1978, after the Hosgri earthquake evaluation, the valves were upgraded by adding a safety-related backup air control system.

During the fourth refueling outages (1991 for Unit 1, 1992 for Unit 2), the backup air system was upgraded to provide independent vital control power for the backup air bottle controls for each valve, and to increase operator flexibility by providing for manual selection of the backup air supply from the main control

room. The backup air system, remote manual controls, and 10 percent ADVs are design Class 1.

To fulfill the safety functions of the ADVs, the two 2200 psig backup air bottles for each ADV must contain sufficient air pressure to operate the valve ten cycles over a six-hour duration. This period was determined to be adequate to mitigate the consequences of an SGTR accident concurrent with the loss of offsite power. A backup air bottle minimum pressure of 260 psig (TS 4.7.1.6.a) provides adequate air to perform the operations assumed in the analysis. To assure that backup air capability is maintained, air bottle pressure is verified daily during operator rounds, and bottles are replaced as required to maintain a substantial margin greater than the TS minimum pressure.

C. SAFETY EVALUATION

Starting with Cycle 5 for each unit, the modified safety-related backup air system and remote manual controls have been tested on a refueling frequency as required by TS 4.7.1.6c. The test verifies that with the normal nitrogen and air supply systems unavailable, the integrity of the backup air system is maintained when the backup system is placed in service. A leak rate test is performed and the ADV is cycled ten times using the remote manual control switches in the control room. The total air usage from the leak rate test and valve cycling is verified to meet the acceptance criteria.

The only portions of the ADV backup air system that are not functionally tested at power are the dedicated backup air solenoids and remote control switches. The solenoids do not experience accelerated aging since, by design, they are normally de-energized. The control switches are of the same models as many others installed in the plant and they have demonstrated satisfactory performance. The control switches are used only for the ADV backup air and do not experience wear during the operating cycle. Consequently, there are no additional mechanical stresses placed on the components due to a potentially longer period between operations.

Operating History

A review of the operating history of the Diablo Canyon 10 percent ADVs was completed. No instances where the backup air supply system was required to operate the ADVs have occurred on either unit. The backup air system has not experienced excessive air leakage during normal power operations. ADV function is assured by quarterly valve stroke testing.

Surveillance History

Data from 24 refueling surveillance tests (3 tests for each of the four ADVs on each unit) were reviewed. The tests cover the past three operating cycles for each unit. All of the tests passed the surveillance requirements for cycling ability and total air usage. The tests identified no component failures and one functional anomaly in the backup air system.

In October 1995, technicians observed that some of the 10 percent ADVs drifted slowly from their initial positions during backup air system testing. Evaluation of the system determined that the drifting was due to small, permissible amounts of air leakage either through a volume booster located in the system or out of the system at the ADV or at fittings. The valves remained controllable and able to meet their safety function, and the drifting is an acceptable consequence of the system design.

The surveillance testing required for TS 4.7.1.6c cannot be completed at power without making an ADV inoperable for an extended period of time from all motive supply sources (normal air, nitrogen, and backup air). However, other surveillances performed at power assure the continued operability of the ADV actuation components. These tests include:

- Daily verification of backup air bottle pressure to satisfy TS 4.7.1.6.a;
- Monthly verification that the ADV block valves are open to satisfy TS 4.7.1.6.b; and
- Quarterly valve stroking of the ADVs to satisfy TS 4.0.5 and 3.6.3 (containment isolation). The quarterly verification is performed with the ADV block valves closed.

Maintenance History

A review of the maintenance history for the eight ADVs (four on each unit) was performed. Maintenance performed on the backup air system has been limited to bottle replacement, associated leak checks, and worn fitting or tubing replacement. The components are in the scope of the Reliability-Centered Maintenance Program and receive routine preventive maintenance.

The backup air system for the ADVs may be maintained while the unit is at power. Consequently, there are no maintenance concerns with extension of the fuel cycle.

Industry Experience

Industry experience and generic NRC communications were reviewed, and no reports were noted that affect the maintenance or operation of the Diablo Canyon SG 10 percent ADVs backup air systems. Maintenance has been performed on the ADVs to address operating experience reports affecting ADV materials.

Summary

The surveillance, maintenance, and operating history of the Diablo Canyon SG 10 percent ADV backup air supply system supports the conclusion that the effect on safety of extending the surveillance interval is small. In addition to the TS 4.7.1.6.c surveillance, other surveillance requirements demonstrate the continued operability of the ADVs and the backup air system. No unsatisfactory time-related dependence is evident for operability of the ADV backup air system for the past three operating cycles.

PG&E believes there is reasonable assurance that the health and safety of the public will not be adversely affected by the proposed TS change.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed change to TS 4.7.1.6c extends the surveillance interval for testing of the backup air supply and remote manual controls of the SG 10 percent ADVs from at least once per 18 months to at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The increased surveillance interval does not alter the intent or method by which the backup air tests are conducted, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the backup air system indicates that the system will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the 10 percent ADV backup air system will continue to effectively perform its design function for longer operating cycles. Additionally, the increased surveillance interval does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   Evaluation of historical surveillance and maintenance data indicates that only routine air bottle replacement and minor leak reduction activities on the backup air system have been required. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition of operation, and there is no hardware change that would impact existing safety analysis acceptance criteria.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 33 -- TECHNICAL SPECIFICATION 4.7.3.1c
PLANT SYSTEMS

VITAL COMPONENT COOLING WATER SYSTEM
AUTOMATIC PUMP START

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would add TS 4.7.3.1c to verify start of each component cooling water (CCW) pump start as follows:

> TS 4.7.3.1c, regarding verification that each CCW pump starts automatically on an actual or simulated actuation signal, would be added with a surveillance frequency of at least once each REFUELING INTERVAL.

The proposed addition is provided in the marked-up copy of TS page 3/4 7-11 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

The function of the CCW system is to provide a heat sink for the removal of process and operating heat from safety-related components during and following a design basis accident (DBA) or transient. During normal operation the CCW system also provides this function for various nonessential components, as well as for the spent fuel storage pool.

The CCW system consists of three pumps fed from three independent vital 4 kV busses that supply two heat exchangers, which in turn feed into three separate loops. Two of these loops serve vital loads and are designed to provide adequate cooling for the safe shutdown of the plant after a DBA. The third loop serves non-vital components and is not required for safe shutdown of the reactor.

When a safety injection (SI) signal is generated, the solid state protection system (SSPS) sends actuation signals to the engineered safety features (ESF) equipment via the slave relays. The slave relays actuate discrete ESF timers, which generate time sequenced start signals to load the ESF pumps onto their respective 4 kV vital busses. The CCW pumps receive automatic SI start signals as part of the sequence. For the purpose of satisfying the proposed TS, the actuation signal may be either an actual or simulated SI signal.

The CCW pumps also receive start signals when no SI signal is present on bus transfer to diesel generator. These starts are surveilled to meet sections of Electrical Power Systems TS 4.8.1.1.1 and 4.8.1.1.2. Additionally, the standby CCW pump receives a nonsafety-related start signal on low pressure in the CCW heat exchanger discharge header. The nonsafety-related signal is not required to satisfy the proposed new TS for testing of automatic CCW pump starts.

The current CCW TS for Diablo Canyon is TS 3.7.3.1, which requires at least two vital CCW loops to be operable in Modes 1 through 4. The action statement allows operation with one vital CCW loop for up to 72 hours. PG&E determined that all three CCW pumps must be operable to satisfy the limiting condition of operation. Any two of the CCW pumps must be operable to satisfy the action statement.

Diablo Canyon has no specific TS-required surveillances for the CCW pumps to start on receipt of an automatic actuation signal. This surveillance is included in NUREG 1431, Revision 1, "Improved Standard Technical Specifications - Westinghouse Plants," as TS 3.7.7.3. In TS 3.7.7.3, the frequency for this surveillance is [18] months, which is based on the need to perform this surveillance under the conditions that apply during a plant outage, on the need to have access to the location, and because of the potential for an unplanned transient if the surveillance were performed with the reactor at power. The frequency has been determined to be sufficient to detect abnormal degradation, as confirmed by operating experience. Brackets around the "18" indicate that the surveillance interval is plant specific and may be adjusted to conform with the refueling interval.

C. SAFETY EVALUATION

The components that function to generate a CCW pump automatic start on SI actuation are the SSPS actuation logic and relays, the ESF timers, the 4 kV breakers, and the CCW pumps themselves. The automatic start on SI of the CCW pumps has been assured by routine performance of quarterly and refueling frequency tests. These tests are discussed in the Surveillance History section.

Additional assurance of circuit operability is provided by several other TS. TS 4.3.2.1 requires testing of the SSPS SI actuation logic every 62 days. TS 4.8.1.1.2b.2) requires verification that the load sequencing timers are operable each outage. The CCW pumps are each tested quarterly pursuant to TS 4.0.5 and the Inservice Test Program.

Operating History

The CCW pumps are used to support normal and accident operations. For normal plant operations, two CCW pumps are running at all times and the third pump is on standby. In the event of an SI, all three pumps receive start signals. A review of the operating history of the Diablo Canyon CCW pumps indicates that no instances of inadequate availability of CCW pumps have occurred. All of the pumps started successfully when actual SI start signals were received.

Surveillance History

Data from seven refueling frequency integrated system surveillance tests were reviewed. The tests cover the past six years of operation on each unit. This surveillance generates multiple SI signals and monitors ESF operation. Signals are generated to simulate SI with offsite power, SI without offsite power, and SI while each diesel generator is paralleled to the electric grid. In each case, all of the CCW pumps responded correctly.

Data from 139 quarterly slave relay tests were reviewed. The tests cover the past six years of operation on each unit. A minimum of 22 tests were reviewed for each CCW pump. In each case, the CCW pumps started successfully.

PG&E submitted LAR 94-11, "Revision of Technical Specification 3/4.3.2 - Slave Relay Test Frequency Relaxation," (PG&E Letter DCL-94-254, dated November 14, 1994) to extend the surveillance interval for slave relay testing from quarterly to refueling frequency. Upon issuance of the amendments, pump starts associated with this surveillance may change to refueling frequency.

Maintenance History

A review of the maintenance history for the last six years, starting in January 1990, for CCW automatic start components was performed. The CCW pumps are in the scope of the Reliability-Centered Maintenance Program.

The SSPS logic and slave relays associated with CCW pump SI starts are located in a mild environment and do not require maintenance. The slave relays are normally de-energized and are not exposed to heating that could cause accelerated aging. There have been no failures of SSPS components used in the CCW start circuitry during this period.

The load sequencing timers for all of the CCW pumps were replaced during this period because the original pneumatic timing relays tended to drift from their setpoints. The replacement relays are solid state timers. No maintenance has been required for the new timers during this period.

The vital 4 kV breakers for the CCW pumps receive routine maintenance each refueling outage and overhaul on a longer periodic schedule. The breakers can be changed out for maintenance if required during plant operation. As noted above, the CCW pump breakers have functioned as required to provide pump starts and runs. Potentially generic problems concerning anti-pump relays and charging springs associated with the breakers were satisfactorily dispositioned on an expedited basis with inspections of 100 percent of the breakers in early 1995.

The CCW motors and pumps receive periodic maintenance and overhaul at intervals that are not dependent on refueling cycle length. There have been no pump or motor failures during this period.

All of these components may be maintained at power, if required. Consequently, there are no maintenance concerns with extension of the fuel cycle.

Industry Experience

Industry experience and generic NRC communications were reviewed, and no reports were noted that would provide significant information on pump start failures.

Summary

The surveillance, maintenance, and operating history of the CCW pump automatic actuation circuitry support the conclusion that the effect on safety from extending the fuel cycle is small. Surveillance testing of the start circuitry has been in place since initial plant operation.

PG&E believes that adding the start verification to the TS with a surveillance frequency of at least once per refueling interval is conservative and will not adversely affect the health and safety of the public.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed addition of TS 4.7.3.1c requires verification that each CCW pump starts automatically on demand at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

The new surveillance on CCW automatic pump start on SI, performed at least once each refueling interval, is a conservative addition to the Diablo Canyon TS. The surveillance requirement does not alter the intent or method by which the CCW pump start verifications are presently conducted in accordance with surveillance test procedures, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the pump start circuitry indicates that the equipment will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the CCW pump start circuitry will continue to effectively perform its design function for longer operating cycles. Additionally, the new surveillance does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   Evaluation of historical surveillance and maintenance data indicates there have been few problems with the CCW pump start circuitry. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition for operation, and there are no hardware changes that would impact existing safety analysis acceptance criteria.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

SAFETY AND NO SIGNIFICANT HAZARDS EVALUATIONS

ITEM 34 -- TECHNICAL SPECIFICATION 4.7.4.2
PLANT SYSTEMS

AUXILIARY SALTWATER SYSTEM
AUTOMATIC PUMP START

A. DESCRIPTION OF CHANGE

This Technical Specification (TS) change would add TS 4.7.4.2 to verify start of each auxiliary saltwater (ASW) pump start as follows:

> TS 4.7.4.2, regarding verification that each ASW pump starts automatically on an actual or simulated actuation signal, would be added with a surveillance frequency of at least once each REFUELING INTERVAL.

The proposed addition is provided in the marked-up copy of TS page 3/4 7-12 in Attachment B. The proposed new TS page is provided in Attachment C.

B. BACKGROUND

The function of the ASW system is to provide a heat sink for the removal of process and operating heat from safety-related components during and following a design basis accident (DBA) or transient. During normal operation, the ASW system also provides this function for various safety-related and nonsafety-related components.

The ASW system consists of two separate, 100 percent capacity, safety-related trains. Each train is composed of one pump, which takes suction from a dedicated bay in the intake structure, and one heat exchanger. Sea water is discharged back to the Pacific Ocean at the outfall. During normal operation, one ASW train is in service with one ASW pump supplying one heat exchanger. The other pump is shutdown and available on standby.

When a safety injection (SI) signal is generated, the solid state protection system (SSPS) sends actuation signals to the engineered safety features (ESF) equipment via the slave relays. The slave relays actuate discrete ESF timers, which generate time sequenced start signals to load the ESF pumps onto their respective 4 kV vital busses. The ASW pumps receive automatic SI start signals as part of the sequence. For the purpose of satisfying the proposed TS, the actuation signal may be either an actual or simulated SI signal.

The ASW pumps also receive start signals when no SI signal is present on bus transfer to startup power or bus transfer to diesel generator. These starts are surveilled to meet sections of Electrical Power Systems TS 4.8.1.1.1 and 4.8.1.1.2. Additionally, the ASW pumps receive nonsafety-related start signals from low discharge header pressure and low voltage on the operating pump's vital bus. The nonsafety-related signals are not required to satisfy the proposed new TS for testing of automatic ASW pump starts.

The current ASW TS for Diablo Canyon is 3/4.7.4, which requires at least two ASW trains to be operable in Modes 1 through 4. The action statement allows operation with one ASW train for up to 72 hours.

Diablo Canyon has no specific TS-required surveillances for the ASW pumps to start on receipt of an automatic actuation signal. This surveillance is included in NUREG 1431, Revision 1, "Improved Standard Technical Specifications - Westinghouse Plants," as TS 3.7.8.3. In TS 3.7.8.3, the frequency for this surveillance is [18] months, which is based on the need to perform this surveillance under the conditions that apply during a plant outage, on the need to have access to the location, and because of the potential for an unplanned transient if the surveillance were performed with the reactor at power. The frequency has been determined to be sufficient to detect abnormal degradation, as confirmed by operating experience. Brackets around the "18" indicate that the surveillance interval is plant specific and may be adjusted to conform with the refueling interval.

C. SAFETY EVALUATION

The components that function to generate a ASW pump automatic start on SI actuation are the SSPS actuation logic and relays, the ESF timers, the 4 kV breakers, and the ASW pumps themselves. The automatic start on SI has been assured by routine performance of quarterly and refueling frequency tests. These tests are discussed in the Surveillance History section.

Additional assurance of circuit operability is provided by several other TS. TS 4.3.2.1 requires testing of the SSPS SI actuation logic every 62 days. TS 4.8.1.1.2b.2) requires verification that the load sequencing timers are operable each outage. The ASW pumps are each tested quarterly pursuant to TS 4.0.5 and the Inservice Test Program.

Operating History

The ASW pumps are used to support normal and accident operations. For normal plant operations, one ASW pump is running at all times and the second pump is

on standby. In the event of an SI, both pumps receive start signals. A review of the operating history of the Diablo Canyon ASW pumps indicates that no instances of inadequate availability of ASW pumps have occurred. All of the pumps started successfully when actual SI start signals were received.

Surveillance History

Data from seven refueling frequency integrated system surveillance tests were reviewed. The tests cover the past five years of operation on each unit. This surveillance generates multiple SI signals and monitors ESF operation. Signals are generated to simulate SI with offsite power, SI without offsite power, and SI while each diesel generator is paralleled to the electric grid. In each case, all of the ASW pumps responded correctly.

Data from 90 quarterly slave relay tests were reviewed. The tests cover the past six years of operation on each unit. A minimum of 22 tests were reviewed for each ASW pump. In each case, the ASW pumps started successfully.

PG&E submitted LAR 94-11, "Revision of Technical Specification 3/4.3.2 - Slave Relay Test Frequency Relaxation," (PG&E Letter DCL-94-254, dated November 14, 1994) to extend the surveillance interval for slave relay testing from quarterly to refueling frequency. Upon issuance of the amendments, pump starts associated with this surveillance may change to refueling frequency.

Maintenance History

A review of the maintenance history for the last six years, starting in January 1990, for ASW automatic start components was performed. The ASW pumps are in the scope of the Reliability-Centered Maintenance Program.

The SSPS logic and slave relays associated with ASW pump SI starts are located in a mild environment and do not require maintenance. The slave relays are normally de-energized and are not exposed to heating that could cause accelerated aging. There have been no failures of SSPS components used in the ASW start circuitry during this period.

The load sequencing timers for all of the ASW pumps were replaced during this period because the original pneumatic timing relays tended to drift from their setpoints. The replacement relays are solid state timers. No maintenance has been required for the new timers during this period.

The vital 4 kV breakers for the ASW pumps receive routine maintenance each refueling outage and overhaul on a longer periodic schedule. The breakers can be changed out for maintenance if required during plant operation. As noted above, the ASW pump breakers have functioned as required to provide pump

starts and runs. Potentially generic problems concerning anti-pump relays and charging springs associated with the breakers were satisfactorily dispositioned on an expedited basis with inspections of 100 percent of the breakers in early 1995.

The ASW motors and pumps receive periodic maintenance and overhaul at intervals that are not dependent on refueling cycle length. There have been no pump or motor failures during this period.

All of these components may be maintained at power, if required. Consequently, there are no maintenance concerns with extension of the fuel cycle.

Industry Experience

Industry experience and generic NRC communications were reviewed, and no reports were noted that would provide significant information on automatic pump start failures.

Summary

The surveillance, maintenance, and operating history of the ASW pump automatic actuation circuitry supports the conclusion that the effect on safety from extending the fuel cycle is small. Surveillance testing of the start circuitry has been in place since initial plant operation.

PG&E believes that adding the start verification to the TS with a surveillance frequency of at least once per refueling interval is conservative and will not adversely affect the health and safety of the public.

D. NO SIGNIFICANT HAZARDS EVALUATION

The proposed addition of TS 4.7.4.2 requires verification that each ASW pump starts automatically on demand at least once per refueling interval (i.e., 24 months nominal +25 percent).

The following evaluation is the basis for the no significant hazards consideration determination.

1. Does the change involve a significant increase in the probability or consequences of an accident previously evaluated?

   The new surveillance on ASW automatic pump start on SI, performed at least once each refueling interval, is a conservative addition to the Diablo Canyon TS. The surveillance requirement does not alter the intent or method by which the ASW pump start verifications are presently conducted in

accordance with surveillance test procedures, does not alter the way any structure, system, or component functions, and does not change the manner in which the plant is operated. The surveillance, maintenance, and operating history of the pump start circuitry indicates that the equipment will continue to perform satisfactorily with a longer surveillance interval. There is no known mechanism that would significantly degrade the performance of this equipment during normal plant operation.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

   The surveillance and maintenance history indicates that the ASW pump start circuitry will continue to effectively perform its design function for longer operating cycles. Additionally, the new surveillance does not result in any physical modifications, affect safety function performance, or alter the intent or method by which surveillance tests are performed.

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the change involve a significant reduction in a margin of safety?

   Evaluation of historical surveillance and maintenance data indicates there have been few problems with the ASW pump start circuitry. There are no indications that potential problems would be cycle-length dependent. There is no safety analysis impact since this change will have no effect on any safety limit, protection system setpoint, or limiting condition for operation, and there are no hardware changes that would impact existing safety analysis acceptance criteria.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.