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

June 8, 1990

Docket Nos. 50-361
and 50-362

Mr. Harold B. Ray
Vice President
Southern California Edison Company
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23 Parker Street
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Mr. Gary D. Cotton
Senior Vice President
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Gentlemen:

SUBJECT: ISSUANCE OF AMENDMENT NO. 88 TO FACILITY OPERATING LICENSE NO. NPF-10 AND AMENDMENT NO. 78 TO FACILITY OPERATING LICENSE NO. NPF-15 SAN ONOFRE NUCLEAR GENERATING STATION, UNITS 2 AND 3 (TAC NOS. 75610, 75611, 75612, 75613, 75614 AND 75615)

The Commission has issued the enclosed amendments to Facility Operating Licenses NPF-10 and NPF-15 for San Onofre Nuclear Generating Station, Unit Nos. 2 and 3, respectively. The amendments consist of changes to the Technical Specifications in response to your applications dated January 8, 1990, supplemented March 12, March 19, and May 2, 1990. These were designated by you as PCN-275, PCN-276 and PCN-280.

The amendments revise San Onofre Units 2 and 3 Technical Specification 3/4.3.1, "Reactor Protective Instrumentation," to increase the interval for refueling interval surveillance tests which are currently performed every 18 months, to each refueling, nominally 24 months and maximum 30 months. As the result of modifying the surveillance interval, changes were made to the Reactor Protective Instrumentation setpoints in Technical Specification 2.2.1, Table 2.2-1; the High Logarithmic Power Level response time in Technical Specification 3/4.3.1, Table 3.3-2; and the calibration tolerance in Technical Specification 3/4.3.1, Table 4.3-1.

The amendments also revise Technical Specification 3/4.3.2, "Engineered Safety Features Actuation System (ESFAS) Instrumentation," to increase the interval for surveillance tests, which are currently performed every 18 months, to each refueling, nominally 24 months and maximum 30 months. As the result of modifying the surveillance interval, changes were made to the ESFAS instrumentation setpoints in Technical Specification 3/4.3.2, Table 3.3-4.

Additionally, the amendments revise Technical Specification 3/4.3.3.5, "Remote Shutdown Instrumentation," to increase the interval for refueling interval surveillance tests which are currently performed every 18 months, to each refueling, nominally 24 months and maximum 30 months.

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A copy of our related Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's next regular biweekly Federal Register notice.

Finally, due to an administrative error in Amendments 47 and 36 to the San Onofre Unit 2 and 3 Technical Specifications respectively, the Table Notation for Table 4.3.1 has been corrected on page 3/4 3-12a. Item 11 on this page no longer states "...per Specification 2.2.2." These amendments were discussed in a safety evaluation dated May 16, 1986, in regard to your submittal known as PCN 206.

Sincerely,

L. E. Kokajko

Lawrence E. Kokajko, Project Manager
Project Directorate V
Division of Reactor Projects - III, IV, V and Special Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 88 to License No. NPF-10
2. Amendment No. 78 to License No. NPF-15
3. Safety Evaluation

cc w/enclosures:
See next page

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Sincerely,

/s/

Lawrence E. Kokajko, Project Manager
Project Directorate V
Division of Reactor Projects - III,
IV, V and Special Projects
Office of Nuclear Reactor Regulation

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cc w/enclosures:
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(14)

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

THE CITY OF ANAHEIM, CALIFORNIA

DOCKET NO. 50-361

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 88
License No. NPF-10

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

   A. The applications for amendment to the license for San Onofre Nuclear Generating Station, Unit 2 (the facility) filed by Southern California Edison Company (SCE) on behalf of itself and San Diego Gas and Electric Company, the City of Riverside, California and the City of Anaheim, California (licensees) dated January 8, 1990, as supplemented by letters dated March 12, March 19, and May 2, 1990, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C(2) of Facility Operating License No. NPF-10 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A, and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 88 , are hereby incorporated in the license. SCE shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and must be fully implemented no later than 45 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Robert B. Samworth

for John T. Larkins, Acting Director
Project Directorate V
Division of Reactor Projects - III,
IV, V and Special Projects
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 8, 1990

ATTACHMENT TO LICENSE AMENDMENT NO. 88

FACILITY OPERATING LICENSE NO. NPF-10

DOCKET NO. 50-361

Revise Appendix A Technical Specifications by removing the pages identified below and inserting the enclosed pages. The revised pages are identified by amendment number and contain marginal lines indicating the area of change. Also enclosed are the following overleaf pages to the amended pages.

AMENDMENT PAGE	OVERLEAF PAGE
2-3	2-4
B 2-3	--
B 2-4	--
3/4 3-8	3/4 3-9
3/4 3-10	--
3/4 3-11	--
3/4 3-12	--
3/4 3-12a	--
3/4 3-22	3/4 3-21
3/4 3-23	3/4 3-24
3/4 3-31	--
3/4 3-32	--
3/4 3-50	3/4 3-49

TABLE 2.2-1

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Linear Power Level - High -		
Four Reactor Coolant Pumps Operating	$\leq$ 110.0% of RATED THERMAL POWER	$\leq$ 111.0% of RATED THERMAL POWER
3. Logarithmic Power Level - High (1)	$\leq$ 0.83% of RATED THERMAL POWER	$\leq$ 0.93% of RATED THERMAL POWER
4. Pressurizer Pressure - High	$\leq$ 2375 psia	$\leq$ 2385 psia
5. Pressurizer Pressure - Low (2)	$\geq$ 1740 psia	$\geq$ 1700 psia
6. Containment Pressure - High	$\leq$ 3.1 psig	$\leq$ 3.4 psig
7. Steam Generator Pressure - Low (3)	$\geq$ 741 psia	$\geq$ 729 psia
8. Steam Generator Level - Low	$\geq$ 21% (4)	$\geq$ 20.0% (4)
9. Local Power Density - High (5)	$\leq$ 21.0 kw/ft	$\leq$ 21.0 kw/ft
10. DNBR - Low	$\geq$ 1.31 (5)	$\geq$ 1.31 (5)
11. Reactor Coolant Flow - Low		
a) DN Rate	$\leq$ 0.22 psid/sec (6)(8)	$\leq$ 0.231 psid/sec (6)(8)
b) Floor	$\geq$ 13.2 psid (6)(8)	$\geq$ 12.1 psid (6)(8)
c) Step	$\leq$ 6.82 psid (6)(8)	$\leq$ 7.25 psid (6)(8)
12. Steam Generator Level - High	$\leq$ 89% (4)	$\leq$ 89.7% (4)
13. Seismic - High	$\leq$ 0.48/0.60 (7)	$\leq$ 0.48/0.60 (7)
14. Loss of Load	Turbine stop valve closed	Turbine stop valve closed

TABLE 2.2-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

TABLE NOTATION

(1) Trip may be manually bypassed above 10^{-4}% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is less than or equal to 10^{-4}% of RATED THERMAL POWER.

(2) Value may be decreased manually, to a minimum value of 300 psia, as pressurizer pressure is reduced, provided the margin between the pressurizer pressure and this value is maintained at less than or equal to 400 psi; the setpoint shall be increased automatically as pressurizer pressure is increased until the trip setpoint is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed whenever pressurizer pressure is greater than or equal to 500 psia.

(3) Value may be decreased manually as steam generator pressure is reduced, provided the margin between the steam generator pressure and this value is maintained at less than or equal to 200 psi; the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached.

(4) % of the distance between steam generator upper and low level instrument nozzles.

(5) As stored within the Core Protection Calculator (CPC). Calculation of the trip setpoint includes measurement, calculational and processor uncertainties, and dynamic allowances. Trip may be manually bypassed below 10^{-4}% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is greater than or equal to 10^{-4}% of RATED THERMAL POWER. The approved DNBR limit accounting for use of HID-2 grids is 1.31. The bypass setpoint may be changed during testing pursuant to Special Test Exception 3.10.2.

(6) DN RATE is the maximum decrease rate of the trip setpoint.

FLOOR is the minimum value of the trip setpoint.

STEP is the amount by which the trip setpoint is below the input signal unless limited by DN Rate or Floor.

(7) Acceleration, horizontal/vertical, g.

(8) Setpoint may be altered to disable trip function during testing pursuant to Specification 3.10.3.

Linear Power Level-High

The Linear Power Level-High trip provides reactor core protection against rapid reactivity excursions which might occur as the result of an ejected CEA, or certain intermediate steam line breaks. This trip initiates a reactor trip at a linear power level of less than or equal to 111.0% of RATED THERMAL POWER.

Logarithmic Power Level-High

The Logarithmic Power Level - High trip is provided to protect the integrity of fuel cladding and the Reactor Coolant System pressure boundary in the event of an unplanned criticality from a shutdown condition. A reactor trip is initiated by the Logarithmic Power Level - High trip at a THERMAL POWER level of less than or equal to 0.93% of RATED THERMAL POWER unless this trip is manually bypassed by the operator. The operator may manually bypass this trip when the THERMAL POWER level is above 10^{-4}% of RATED THERMAL POWER; this bypass is automatically removed when the THERMAL POWER level decreases to 10^{-4}% of RATED THERMAL POWER.

Pressurizer Pressure-High

The Pressurizer Pressure-High trip, in conjunction with the pressurizer safety valves and main steam safety valves, provides reactor coolant system protection against overpressurization in the event of loss of load without reactor trip. This trip's setpoint is at less than or equal to 2385 psia which is below the nominal lift setting 2500 psia of the pressurizer safety valves and its operation avoids the undesirable operation of the pressurizer safety valves.

Pressurizer Pressure-Low

The Pressurizer Pressure-Low trip is provided to trip the reactor and to assist the Engineered Safety Features System in the event of a Loss of Coolant Accident. During normal operation, this trip's setpoint is set at greater than or equal to 1700 psia. This trip's setpoint may be manually decreased, to a minimum value of 300 psia, as pressurizer pressure is reduced during plant shutdowns, provided the margin between the pressurizer pressure and this trip's setpoint is maintained at less than or equal to 400 psi; this setpoint increases automatically as pressurizer pressure increases until the trip setpoint is reached.

Containment Pressure-High

The Containment Pressure-High trip provides assurance that a reactor trip is initiated prior to safety injection actuation.

Steam Generator Pressure-Low

The Steam Generator Pressure-Low trip provides protection against an excessive rate of heat extraction from the steam generators and subsequent cooldown of the reactor coolant. The setpoint is sufficiently below the full load operating point of approximately 900 psia so as not to interfere with normal operation, but still high enough to provide the required protection in the event of excessively high steam flow. This trip's setpoint may be manually decreased as steam generator pressure is reduced during plant shutdowns, provided the margin between the steam generator pressure and this trip's setpoint is maintained at less than or equal to 200 psi; this setpoint increases automatically as steam generator pressure increases until the trip setpoint is reached.

Steam Generator Level-Low

The Steam Generator Level-Low trip provides protection against a loss of feedwater flow incident and assures that the design pressure of the Reactor Coolant System will not be exceeded due to loss of the steam generator heat sink. This specified setpoint provides allowance that there will be sufficient water inventory in the steam generator at the time of the trip to provide a margin of at least 10 minutes before emergency feedwater is required.

Local Power Density-High

The Local Power Density-High trip is provided to prevent the linear heat rate (kw/ft) in the limiting fuel rod in the core from exceeding the fuel design limit in the event of any anticipated operational occurrence. The local power density is calculated in the reactor protective system utilizing the following information:

a. Nuclear flux power and axial power distribution from the excore flux monitoring system;

b. Radial peaking factors from the position measurement for the CEAs;

c. Delta T power from reactor coolant temperatures and coolant flow measurements.

TABLE 3.3-2

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	Not Applicable
2. Linear Power Level - High	$\leq$ 0.40 seconds*
3. Logarithmic Power Level - High	$\leq$ 0.40 seconds*
4. Pressurizer Pressure - High	$\leq$ 1.90 seconds
5. Pressurizer Pressure - Low	$\leq$ 0.90 seconds
6. Containment Pressure - High	$\leq$ 0.90 seconds
7. Steam Generator Pressure - Low	$\leq$ 0.90 seconds
8. Steam Generator Level - Low	$\leq$ 0.90 seconds
9. Local Power Density - High	
a. Neutron Flux Power from Excor Neutron Detectors	$\leq$ 0.68 seconds*
b. CEA Positions	$\leq$ 0.68 seconds**
c. CEA Positions: CEAC Penalty Factor	$\leq$ 0.53 seconds
10. DNBR - Low	
a. Neutron Flux Power from Excore Neutron Detectors	$\leq$ 0.68 seconds*
b. CEA Positions	$\leq$ 0.68 seconds**
c. Cold Leg Temperature	$\leq$ 0.68 seconds##
d. Hot Leg Temperature	$\leq$ 0.68 seconds##
e. Primary Coolant Pump Shaft Speed	$\leq$ 0.68 seconds#
f. Reactor Coolant Pressure from Pressurizer	$\leq$ 0.68 seconds
g. CEA positions: CEAC Penalty Factor	$\leq$ 0.53 seconds

TABLE 3.3-2 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
11. Steam Generator Level - High	Not Applicable
12. Reactor Protection System Logic	Not Applicable
13. Reactor Trip Breakers	Not Applicable
14. Core Protection Calculators	Not Applicable
15. CEA Calculators	Not Applicable
16. Reactor Coolant Flow-Low	0.9 sec
17. Seismic-High	Not Applicable
18. Loss of Load	Not Applicable

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

**Response time shall be measured from the onset of a single CEA drop.

#Response time shall be measured using a simulated Reactor Coolant Pump coastdown.

##Based on a resistance temperature detector (RTD) response time of less than or equal to 8.0 seconds where the RTD response time is equivalent to the time interval required for the RTD output to achieve 63.2% of its total change when subjected to a step change in RTD temperature.

TABLE 4.3-1

REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	#	1, 2, 3*, 4*, 5*
2. Linear Power Level - High	S	D(2,4),M(3,4), Q(4), #(4)	M	1, 2
3. Logarithmic Power Level - High	S	#(4)	M and S/U(1)	1, 2, 3, 4, 5
4. Pressurizer Pressure - High	S	#	M	1, 2
5. Pressurizer Pressure - Low	S	#	M	1, 2
6. Containment Pressure - High	S	#	M	1, 2
7. Steam Generator Pressure - Low	S	#	M	1, 2
8. Steam Generator Level - Low	S	#	M	1, 2
9. Local Power Density - High	S	D(2,4), #(4,5)	M, #(6)	1, 2
10. DNBR - Low	S	S(7), D(2,4), M(8), #(4,5)	M, #(6)	1, 2
11. Steam Generator Level - High	S	#	M	1, 2
12. Reactor Protection System Logic	N.A.	N.A.	M	1, 2, 3*, 4*, 5*

TABLE 4.3-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
13. Reactor Trip Breakers	N.A.	N.A.	M,(12)	1, 2, 3*, 4*, 5*
14. Core Protection Calculators	S	D(2,4),S(7) #(4,5),M(8)	M(11),#(6)	1, 2
15. CEA Calculators	S	#	M,#(6)	1, 2
16. Reactor Coolant Flow-Low	S	#	M	1, 2
17. Seismic-High	S	#	M	1, 2
18. Loss of Load	S	N.A.	M	1 (9)

TABLE 4.3-1 (Continued)

TABLE NOTATION

* - With reactor trip breakers in the closed position and the CEA drive system capable of CEA withdrawal.

- At least once per Refueling Interval.

(1) - Each startup or when required with the reactor trip breakers closed and the CEA drive system capable of rod withdrawal, if not performed in the previous 7 days.

(2) - Heat balance only (CHANNEL FUNCTIONAL TEST not included), above 15% of RATED THERMAL POWER; adjust the Linear Power Level signals and the CPC addressable constant multipliers to make the CPC delta T power and CPC nuclear power calculations agree with the calorimetric calculation if absolute difference is greater than 2%. During PHYSICS TESTS, these daily calibrations may be suspended provided these calibrations are performed upon reaching each major test power plateau and prior to proceeding to the next major test power plateau.

(3) - Above 15% of RATED THERMAL POWER, verify that the linear power subchannel gains of the excore detectors are consistent with the values used to establish the shape annealing matrix elements in the Core Protection Calculators.

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

(5) - After each fuel loading and prior to exceeding 70% of RATED THERMAL POWER, the incore detectors shall be used to determine the shape annealing matrix elements and the Core Protection Calculators shall use these elements.

(6) - This CHANNEL FUNCTIONAL TEST shall include the injection of simulated process signals into the channel as close to the sensors as practicable to verify OPERABILITY including alarm and/or trip functions.

(7) - Above 70% of RATED THERMAL POWER, verify that the total RCS flow rate as indicated by each CPC is less than or equal to the actual RCS total flow rate determined by either using the reactor coolant pump differential pressure instrumentation (conservatively compensated for measurement uncertainties) or by calorimetric calculations (conservatively compensated for measurement uncertainties) and if necessary, adjust the CPC addressable constant flow coefficients such that each CPC indicated flow is less than or equal to the actual flow rate. The flow measurement uncertainty may be included in the BERR1 term in the CPC and is equal to or greater than 4%.

(8) - Above 70% of RATED THERMAL POWER, verify that the total RCS flow rate as indicated by each CPC is less than or equal to the actual RCS total flow rate determined by calorimetric calculations (conservatively compensated for measurement uncertainties).

(9) - Above 55% of RATED THERMAL POWER.

(10) - Deleted.

TABLE 4.3-1 (Continued)

TABLE NOTATION

(11) - The monthly CHANNEL FUNCTIONAL TEST shall include verification that the correct values of addressable constants are installed in each OPERABLE CPC.

(12) - At least once per 18 months and following maintenance or adjustment of the reactor trip breakers, the CHANNEL FUNCTIONAL TEST shall include independent verification of the undervoltage and shunt trips.

Table 3.3-3 (Continued)

TABLE NOTATION

ACTION 13 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, within 1 hour initiate and maintain operation of the control room emergency air cleanup system in the emergency (except as required by ACTIONS 14, 15) mode of operation.

ACTION 14 - With the number of channels OPERABLE one less than the total number of channels, restore the inoperable channel to OPERABLE status within 7 days or within the next 6 hours initiate and maintain operation of the control room emergency air cleanup system in the isolation mode of operation.

ACTION 15 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, within 1 hour initiate and maintain operation of the control room emergency air cleanup system in the isolation mode of operation.

ACTION 16 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.9.12.

ACTION 17 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, operation may continue provided that the purge valves are maintained closed.

ACTION 17a - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.4.5.1. (Mode 1, 2, 3, 4 only)

ACTION 17b - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, close each of the containment purge penetrations providing direct access from the containment atmosphere to the outside atmosphere.

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
1. SAFETY INJECTION (SIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	$\leq$ 3.4 psig	$\leq$ 3.7 psig
c. Pressurizer Pressure - Low	$\geq$ 1740 psia (1)	$\geq$ 1700 psia (1)
d. Automatic Actuation Logic	Not Applicable	Not Applicable
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure -- High-High	$\leq$ 14.0 psig	$\leq$ 15.0 psig
c. Automatic Actuation Logic	Not Applicable	Not Applicable
3. CONTAINMENT ISOLATION (CIAS)		
a. Manual CIAS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons)[(5)]	Not Applicable	Not Applicable
c. Containment Pressure - High	$\leq$ 3.4 psig	$\leq$ 3.7 psig
d. Automatic Actuation Logic	Not Applicable	Not Applicable
4. MAIN STEAM ISOLATION (MSIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator Pressure - Low	$\geq$ 741 psia (2)	$\geq$ 729 psia (2)
c. Automatic Actuation Logic	Not Applicable	Not Applicable
5. RECIRCULATION (RAS)		
a. Refueling Water Storage Tank	18.5% of tap span	19.27% $\geq$ tap span $\geq$ 17.73%
b. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
6. CONTAINMENT COOLING (CCAS)		
a. Manual CCAS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons)	Not Applicable	Not Applicable
c. Automatic Actuation Logic	Not Applicable	Not Applicable
7. LOSS OF POWER (LOV)		
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage and Degraded Voltage)	See Fig. 3.3-1 (4)	See Fig. 3.3-1 (4)
8. EMERGENCY FEEDWATER (EFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator (A&B) Level-Low	$\geq$ 21% (3)	$\geq$ 20% (3)
c. Steam Generator ΔP-High (SG-A > SG-B)	$\leq$ 125 psi	$\leq$ 140 psi
d. Steam Generator ΔP-High (SG-B > SG-A)	$\leq$ 125 psi	$\leq$ 140 psi
e. Steam Generator (A&B) Pressure - Low	$\geq$ 741 psia (2)	$\geq$ 729 psia (2)
f. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
9. CONTROL ROOM ISOLATION (CRIS)		
a. Manual CRIS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons)	Not Applicable	Not Applicable
c. Airborne Radiation		
i. Particulate/Iodine	$\leq 5.7 \times 10^4$ cpm**	$\leq 6.0 \times 10^4$ cpm**
ii. Gaseous	$\leq 3.8 \times 10^2$ cpm**	$\leq 4.0 \times 10^2$ cpm**
d. Automatic Actuation Logic	Not Applicable	Not Applicable
10. TOXIC GAS ISOLATION (TGIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Chlorine - High	$\leq$ 14.3 ppm	$\leq$ 15.0 ppm
c. Ammonia - High	$\leq$ 97 ppm	$\leq$ 100 ppm
d. Butane/Propane - High	$\leq$ 193 ppm	$\leq$ 200 ppm
e. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 4.3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. SAFETY INJECTION (SIAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3, 4
b. Containment Pressure - High	S	(6)	M	1, 2, 3
c. Pressurizer Pressure - Low	S	(6)	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3, 4
2. CONTAINMENT SPRAY (CSAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3
b. Containment Pressure -- High - High	S	(6)	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3
3. CONTAINMENT ISOLATION (CIAS)				
a. Manual CIAS (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3, 4
b. Manual SIAS (Trip Buttons)(5)	N.A.	N.A.	(6)	1, 2, 3, 4
c. Containment Pressure - High	S	(6)	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3, 4
4. MAIN STEAM ISOLATION (MSIS)				
a. Manual (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3
b. Steam Generator Pressure - Low	S	(6)	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3
5. RECIRCULATION (RAS)				
a. Refueling Water Storage Tank - Low	S	R	M	1, 2, 3, 4
b. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3, 4
6. CONTAINMENT COOLING (CCAS)				
a. Manual CCAS (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3, 4
b. Manual SIAS (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3, 4
c. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3, 4

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
7. LOSS OF POWER (LOV)				
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage and Degraded Voltage)	S	(6)	(6)	1, 2, 3, 4
8. EMERGENCY FEEDWATER (EFAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3
b. SG Level (A/B)-Low and ΔP (A/B) - High	S	(6)	M	1, 2, 3
c. SG Level (A/B) - Low and No Pressure - Low Trip (A/B)	S	(6)	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3
9. CONTROL ROOM ISOLATION (CRIS)				
a. Manual CRIS (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Manual SIAS (Trip Buttons)	N.A.	N.A.	R	N.A.
c. Airborne Radiation				
i. Particulate/Iodine	S	R	M	All
ii. Gaseous	S	R	M	All
d. Automatic Actuation Logic	N.A.	N.A.	R(3)	All
10. TOXIC GAS ISOLATION (TGIS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Chlorine - High	S	R	M	All
c. Ammonia - High	S	R	M	All
d. Butane/Propane - High	S	R	M	All
e. Automatic Actuation Logic	N.A.	N.A.	R (3)	All

TABLE [illegible] 9
REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	CHANNEL RANGE	MINIMUM CHANNELS OPERABLE
1. Log Power Level	*	10^{-8} - 200%	1
2. Reactor Coolant Cold Leg Temperature	#	0-700°F(a)	1
3. Pressurizer Pressure	*	0-3000 psia	1
4. Pressurizer Level	*	0-100%	1
5. Steam Generator Pressure	*	0-1200 psia	1/steam generator
6. Steam Generator Level	*	0-100%	1/steam generator
7. Source Range Neutron Flux	*	10^{-1}-10^{5} cps	1
8. Condenser Vacuum	*	0-5" Hg	1
9. Volume Control Tank Level	*	0-100%	1
10. Letdown Heat Exchanger Pressure	*	0-600 psig	1
11. Letdown Heat Exchanger Temperature	*	0-200°F	1
12. Boric Acid Makeup Tank Level	*	0-100%	1
13. Condensate Storage Tank Level	*	0-100%	1
14. Reactor Coolant Hot Leg Temperature	#	0-700°F(b)	1
15. Pressurizer Pressure - Low Range	#	0-1600 psia	1
16. Pressurizer Pressure - High Range	#	1500-2500 psia	1
17. Pressurizer Level	#	0-100%	1
18. Steam Generator Pressure	#	0-1050 psia	1/steam generator
19. Steam Generator Level	#	0-100%	1/steam generator

*Panel L042
#Panel L411

(a) 0-600°F until completion of DCP 6604
(b) 190-625°F until completion of DCP 6604

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Log Power Level	M	(1)
2. Reactor Coolant Cold Leg Temperature	M	(1)
3. Pressurizer Pressure	M	(1)
4. Pressurizer Level	M	(1)
5. Steam Generator Level	M	(1)
6. Steam Generator Pressure	M	(1)
7. Source Range Neutron Flux	M	(1)
8. Condenser Vacuum	M	(1)
9. Volume Control Tank Level	M	(1)
10. Letdown Heat Exchanger Pressure	M	(1)
11. Letdown Heat Exchanger Temperature	M	(1)
12. Boric Acid Makeup Tank Level	M	(1)
13. Condensate Storage Tank Level	M	(1)
14. Reactor Coolant Hot Leg Temperature	M	(1)
15. Pressurizer Pressure - Low Range	M	(1)
16. Pressurizer Pressure - High Range	M	(1)
17. Pressurizer Level	M	(1)
18. Steam Generator Pressure	M	(1)
19. Steam Generator Level	M	(1)

TABLE NOTATION

(1) At least once per Refueling Interval.

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

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

THE CITY OF ANAHEIM, CALIFORNIA

DOCKET NO. 50-362

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT NO. 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 78
License No. NPF-15

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

   A. The applications for amendment to the license for San Onofre Nuclear Generating Station, Unit 3 (the facility) filed by Southern California Edison Company (SCE) on behalf of itself and San Diego Gas and Electric Company, the City of Riverside, California and the City of Anaheim, California (licensees) dated January 8, 1990, as supplemented by letters dated March 12, March 19, and May 2, 1990, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C(2) of Facility Operating License No. NPF-15 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A, and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 78 , are hereby incorporated in the license. SCE shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and must be fully implemented no later than 45 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Robert B. Samworth for

John T. Larkins, Acting Director
Project Directorate V
Division of Reactor Projects - III,
IV, V and Special Projects
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: June 8, 1990

ATTACHMENT TO LICENSE AMENDMENT NO. 78

FACILITY OPERATING LICENSE NO. NPF-15

DOCKET NO. 50-362

Revise Appendix A Technical Specifications by removing the pages identified below and inserting the enclosed pages. The revised pages are identified by amendment number and contain marginal lines indicating the area of change. Also enclosed are the following overleaf pages to the amended pages.

AMENDMENT PAGE	OVERLEAF PAGE
2-3	2-4
B 2-3	--
B 2-4	--
3/4 3-8	3/4 3-9
3/4 3-10	--
3/4 3-11	--
3/4 3-12	--
3/4 3-12a	--
3/4 3-22	3/4 3-21
3/4 3-23	3/4 3-24
3/4 3-31	--
3/4 3-32	--
3/4 3-50	3/4 3-49

TABLE 2.2-1

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Linear Power Level - High -		
Four Reactor Coolant Pumps Operating	≤ 110.0% of RATED THERMAL POWER	≤ 111.0% of RATED THERMAL POWER
3. Logarithmic Power Level - High (1)	≤ 0.83% of RATED THERMAL POWER	≤ 0.93% of RATED THERMAL POWER
4. Pressurizer Pressure - High	≤ 2375 psia	≤ 2385 psia
5. Pressurizer Pressure - Low (2)	≥ 1740 psia	≥ 1700 psia
6. Containment Pressure - High	≤ 3.1 psig	≤ 3.4 psig
7. Steam Generator Pressure - Low (3)	≥ 741 psia	≥ 729 psia
8. Steam Generator Level - Low	≥ 21.0% (4)	≥ 20.0% (4)
9. Local Power Density - High (5)	≤ 21.0 kw/ft	≤ 21.0 kw/ft
10. DNBR - Low	≥ 1.31 (5)	≥ 1.31 (5)
11. Reactor Coolant Flow - Low		
a) DN Rate	≤ 0.22 psid/sec (6)(8)	≤ 0.231 psid/sec (6)(8)
b) Floor	≥ 13.2 psid (6)(8)	≤ 12.1 psid (6)(8)
c) Step	≤ 6.82 psid (6)(8)	≤ 7.25 psid (6)(8)
12. Steam Generator Level - High	≤ 89% (4)	≤ 89.7% (4)
13. Seismic - High	≤ 0.48/0.60 (7)	≤ 0.48/0.60 (7)
14. Loss of Load	Turbine stop valve closed	Turbine stop valve closed

TABLE 2.2-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

TABLE NOTATION

(1) Trip may be manually bypassed above 10-4% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is less than or equal to 10-4% of RATED THERMAL POWER.

(2) Value may be decreased manually, to a minimum value of 300 psia, as pressurizer pressure is reduced, provided the margin between the pressurizer pressure and this value is maintained at less than or equal to 400 psi; the setpoint shall be increased automatically as pressurizer pressure is increased until the trip setpoint is reached. Trip may be manually bypassed below 400 psia; bypass shall be automatically removed whenever pressurizer pressure is greater than or equal to 500 psia.

(3) Value may be decreased manually as steam generator pressure is reduced, provided the margin between the steam generator pressure and this value is maintained at less than or equal to 200 psi; the setpoint shall be increased automatically as steam generator pressure is increased until the trip setpoint is reached.

(4) % of the distance between steam generator upper and low level instrument nozzles.

(5) As stored within the Core Protection Calculator (CPC). Calculation of the trip setpoint includes measurement, calculational and processor uncertainties, and dynamic allowances. Trip may be manually bypassed below 10-4% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is greater than or equal to 10-4% of RATED THERMAL POWER. The approved DNBR limit accounting for use of HID-2 grid is 1.31. The bypass setpoint may be changed during testing pursuant to Special Test Exception 3.10.2.

(6) DN RATE is the maximum decrease rate of the trip setpoint.

FLOOR is the minimum value of the trip setpoint.

STEP is the amount by which the trip setpoint is below the input signal unless limited by DN Rate or Floor.

(7) Acceleration, horizontal/vertical, g.

(8) Setpoint may be altered to disable trip function during testing pursuant to Specification 3.10.3.

Linear Power Level-High

The Linear Power Level-High trip provides reactor core protection against rapid reactivity excursions which might occur as the result of an ejected CEA, or certain intermediate steam line breaks. This trip initiates a reactor trip at a linear power level of less than or equal to 111.0% of RATED THERMAL POWER.

Logarithmic Power Level-High

The Logarithmic Power Level - High trip is provided to protect the integrity of fuel cladding and the Reactor Coolant System pressure boundary in the event of an unplanned criticality from a shutdown condition. A reactor trip is initiated by the Logarithmic Power Level - High trip at a THERMAL POWER level of less than or equal to 0.93% of RATED THERMAL POWER unless this trip is manually bypassed by the operator. The operator may manually bypass this trip when the THERMAL POWER level is above 10^{-4}% of RATED THERMAL POWER; this bypass is automatically removed when the THERMAL POWER level decreases to 10^{-4}% of RATED THERMAL POWER.

Pressurizer Pressure-High

The Pressurizer Pressure-High trip, in conjunction with the pressurizer safety valves and main steam safety valves, provides reactor coolant system protection against overpressurization in the event of loss of load without reactor trip. This trip's setpoint is at less than or equal to 2385 psia which is below the nominal lift setting 2500 psia of the pressurizer safety valves and its operation avoids the undesirable operation of the pressurizer safety valves.

Pressurizer Pressure-Low

The Pressurizer Pressure-Low trip is provided to trip the reactor and to assist the Engineered Safety Features System in the event of a Loss of Coolant Accident. During normal operation, this trip's setpoint is set at greater than or equal to 1700 psia. This trip's setpoint may be manually decreased, to a minimum value of 300 psia, as pressurizer pressure is reduced during plant shutdowns, provided the margin between the pressurizer pressure and this trip's setpoint is maintained at less than or equal to 400 psi; this setpoint increases automatically as pressurizer pressure increases until the trip setpoint is reached.

Containment Pressure-High

The Containment Pressure-High trip provides assurance that a reactor trip is initiated prior to safety injection actuation.

Steam Generator Pressure-Low

The Steam Generator Pressure-Low trip provides protection against an excessive rate of heat extraction from the steam generators and subsequent cooldown of the reactor coolant. The setpoint is sufficiently below the full load operating point of approximately 900 psia so as not to interfere with normal operation, but still high enough to provide the required protection in the event of excessively high steam flow. This trip's setpoint may be manually decreased as steam generator pressure is reduced during plant shutdowns, provided the margin between the steam generator pressure and this trip's setpoint is maintained at less than or equal to 200 psi; this setpoint increases automatically as steam generator pressure increases until the trip setpoint is reached.

Steam Generator Level-Low

The Steam Generator Level-Low trip provides protection against a loss of feedwater flow incident and assures that the design pressure of the Reactor Coolant System will not be exceeded due to loss of the steam generator heat sink. This specified setpoint provides allowance that there will be sufficient water inventory in the steam generator at the time of the trip to provide a margin of at least 10 minutes before emergency feedwater is required.

Local Power Density-High

The Local Power Density-High trip is provided to prevent the linear heat rate (kw/ft) in the limiting fuel rod in the core from exceeding the fuel design limit in the event of any anticipated operational occurrence. The local power density is calculated in the reactor protective system utilizing the following information:

a. Nuclear flux power and axial power distribution from the excore flux monitoring system;

b. Radial peaking factors from the position measurement for the CEAs;

c. Delta T power from reactor coolant temperatures and coolant flow measurements.

TABLE 3.3-2

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	Not Applicable
2. Linear Power Level - High	≤ 0.40 seconds*
3. Logarithmic Power Level - High	≤ 0.40 seconds*
4. Pressurizer Pressure - High	≤ 0.90 seconds
5. Pressurizer Pressure - Low	≤ 0.90 seconds
6. Containment Pressure - High	≤ 0.90 seconds
7. Steam Generator Pressure - Low	≤ 0.90 seconds
8. Steam Generator Level - Low	≤ 0.90 seconds
9. Local Power Density - High	
a. Neutron Flux Power from Excore Neutron Detectors	≤ 0.68 seconds*
b. CEA Positions	≤ 0.68 seconds**
c. CEA Positions: CEAC Penalty Factor	≤ 0.53 seconds
10. DNBR - Low	
a. Neutron Flux Power from Excore Neutron Detectors	≤ 0.68 seconds*
b. CEA Positions	≤ 0.68 seconds**
c. Cold Leg Temperature	≤ 0.68 seconds##
d. Hot Leg Temperature	≤ 0.68 seconds##
e. Primary Coolant Pump Shaft Speed	≤ 0.68 seconds#
f. Reactor Coolant Pressure from Pressurizer	≤ 0.68 seconds
g. CEA positions: CEAC Penalty Factor	≤ 0.53 seconds

TABLE 3.3-2 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
11. Steam Generator Level - High	Not Applicable
12. Reactor Protection System Logic	Not Applicable
13. Reactor Trip Breakers	Not Applicable
14. Core Protection Calculators	Not Applicable
15. CEA Calculators	Not Applicable
16. Reactor Coolant Flow-Low	0.9 sec
17. Seismic-High	Not Applicable
18. Loss of Load	Not Applicable

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

** Response time shall be measured from the onset of a single CEA drop.

Response time shall be measured using a simulated Reactor Coolant Pump coastdown.

Based on a resistance temperature detector (RTD) response time of less than or equal to 8 seconds where the RTD response time is equivalent to the time interval required for the RTD output to achieve 63.2% of its total change when subjected to a step change in RTD temperature.

TABLE 4.3-1

REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	#	1, 2, 3*, 4*, 5*
2. Linear Power Level - High	S	D(2,4),M(3,4), Q(4), #(4)	M	1, 2
3. Logarithmic Power Level - High	S	#(4)	M and S/U(1)	1, 2, 3, 4, 5
4. Pressurizer Pressure - High	S	#	M	1, 2
5. Pressurizer Pressure - Low	S	#	M	1, 2
6. Containment Pressure - High	S	#	M	1, 2
7. Steam Generator Pressure - Low	S	#	M	1, 2
8. Steam Generator Level - Low	S	#	M	1, 2
9. Local Power Density - High	S	D(2,4), #(4,5)	M, #(6)	1, 2
10. DNBR - Low	S	S(7), D(2,4), M(8), #(4,5)	M, #(6)	1, 2
11. Steam Generator Level - High	S	#	M	1, 2
12. Reactor Protection System Logic	N.A.	N.A.	M	1, 2, 3*, 4*, 5*

TABLE 4.3-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
13. Reactor Trip Breakers	N.A.	N.A.	M,(12)	1, 2, 3*, 4*, 5*
14. Core Protection Calculators	S	D(2,4), S(7), #(4,5), M(8)	M(11),#(6)	1, 2
15. CEA Calculators	S	#	M,#(6)	1, 2
16. Reactor Coolant Flow-Low	S	#	M	1, 2
17. Seismic-High	S	#	M	1, 2
18. Loss of Load	S	N.A.	M	1 (9)

TABLE 4.3-1 (Continued)

TABLE NOTATION

* - With reactor trip breakers in the closed position and the CEA drive system capable of CEA withdrawal.

- At least once per Refueling Interval.

(1) - Each startup or when required with the reactor trip breakers closed and the CEA drive system capable of rod withdrawal, if not performed in the previous 7 days.

(2) - Heat balance only (CHANNEL FUNCTIONAL TEST not included), above 15% of RATED THERMAL POWER; adjust the Linear Power Level signals and the CPC addressable constant multipliers to make the CPC delta T power and CPC nuclear power calculations agree with the calorimetric calculation if absolute difference is greater than 2%. During PHYSICS TESTS, these daily calibrations may be suspended provided these calibrations are performed upon reaching each major test power plateau and prior to proceeding to the next major test power plateau.

(3) - Above 15% of RATED THERMAL POWER, verify that the linear power subchannel gains of the excore detectors are consistent with the values used to establish the shape annealing matrix elements in the Core Protection Calculators.

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

(5) - After each fuel loading and prior to exceeding 70% of RATED THERMAL POWER, the incore detectors shall be used to determine the shape annealing matrix elements and the Core Protection Calculators shall use these elements.

(6) - This CHANNEL FUNCTIONAL TEST shall include the injection of simulated process signals into the channel as close to the sensors as practicable to verify OPERABILITY including alarm and/or trip functions.

(7) - Above 70% of RATED THERMAL POWER, verify that the total RCS flow rate as indicated by each CPC is less than or equal to the actual RCS total flow rate determined by either using the reactor coolant pump differential pressure instrumentation (conservatively compensated for measurement uncertainties) or by calorimetric calculations (conservatively compensated for measurement uncertainties) and if necessary, adjust the CPC addressable constant flow coefficients such that each CPC indicated flow is less than or equal to the actual flow rate. The flow measurement uncertainty may be included in the BERR1 term in the CPC and is equal to or greater than 4%.

(8) - Above 70% of RATED THERMAL POWER, verify that the total RCS flow rate as indicated by each CPC is less than or equal to the actual RCS total flow rate determined by calorimetric calculations (conservatively compensated for measurement uncertainties).

(9) - Above 55% of RATED THERMAL POWER.

(10) - Deleted.

TABLE 4.3-1 (Continued)

TABLE NOTATION

(11) - The monthly CHANNEL FUNCTIONAL TEST shall include verification that the correct values of addressable constants are installed in each OPERABLE CPC.

(12) - At least once per 18 months and following maintenance or adjustment of the reactor trip breakers, the CHANNEL FUNCTIONAL TEST shall include independent verification of the undervoltage and shunt trips.

Table 3.3-3 (Continued)

TABLE NOTATION

ACTION 13 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, within 1 hour initiate and maintain operation of the control room emergency air cleanup system in the emergency (except as required by ACTIONS 14, 15) mode of operation.

ACTION 14 - With the number of channels OPERABLE one less than the total number of channels, restore the inoperable channel to OPERABLE status within 7 days or within the next 6 hours initiate and maintain operation of the control room emergency air cleanup system in the isolation mode of operation.

ACTION 15 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, within 1 hour initiate and maintain operation of the control room emergency air cleanup system in the isolation mode of operation.

ACTION 16 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.9.12.

ACTION 17 - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, operation may continue provided that the purge valves are maintained closed.

ACTION 17a - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.4.5.1. (MODE 1, 2, 3,4 only)

ACTION 17b - With the number of channels OPERABLE less than required by the minimum channels OPERABLE requirement, close each of the containment purge penetrations providing direct access from the containment atmosphere to the outside atmosphere.

TABLE 3.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT			TRIP VALUE	ALLOWABLE VALUES
1.	SAFETY INJECTION (SIAS)			
	a.	Manual (Trip Buttons)	Not Applicable	Not Applicable
	b.	Containment Pressure - High	≤ 3.4 psig	≤ 3.7 psig
	c.	Pressurizer Pressure - Low	≥ 1740 psia (1)	≥ 1700 psia (1)
	d.	Automatic Actuation Logic	Not Applicable	Not Applicable
2.	CONTAINMENT SPRAY (CSAS)			
	a.	Manual (Trip Buttons)	Not Applicable	Not Applicable
	b.	Containment Pressure -- High-High	≤ 14.0 psig	≤ 15.0 psig
	c.	Automatic Actuation Logic	Not Applicable	Not Applicable
3.	CONTAINMENT ISOLATION (CIAS)			
	a.	Manual CIAS (Trip Buttons)	Not Applicable	Not Applicable
	b.	Manual SIAS (Trip Buttons)(5)	Not Applicable	Not Applicable
	c.	Containment Pressure - High	≤ 3.4 psig	≤ 3.7 psig
	d.	Automatic Actuation Logic	Not Applicable	Not Applicable
4.	MAIN STEAM ISOLATION (MSIS)			
	a.	Manual (Trip Buttons)	Not Applicable	Not Applicable
	b.	Steam Generator Pressure - Low	≥ 741 psia (2)	≥ 729 psia (2)
	c.	Automatic Actuation Logic	Not Applicable	Not Applicable
5.	RECIRCULATION (RAS)			
	a.	Refueling Water Storage Tank	18.5% of tap span	19.27% ≥ tap span ≥ 17.73%
	b.	Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
6. CONTAINMENT COOLING (CCAS)		
a. Manual CCAS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons)	Not Applicable	Not Applicable
c. Automatic Actuation Logic	Not Applicable	Not Applicable
7. LOSS OF POWER (LOV)		
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage and Degraded Voltage)	See Fig. 3.3-1 (4)	See Fig. 3.3-1 (4)
8. EMERGENCY FEEDWATER (EFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator (A&B) Level-Low	$\geq$ 21% (3)	$\geq$ 20% (3)
c. Steam Generator ΔP-High (SG-A > SG-B)	$\leq$ 125 psi	$\leq$ 140 psi
d. Steam Generator ΔP-High (SG-B > SG-A)	$\leq$ 125 psi	$\leq$ 140 psi
e. Steam Generator (A&B) Pressure - Low	$\geq$ 741 psia (2)	$\geq$ 729 psia (2)
f. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
9. CONTROL ROOM ISOLATION (CRIS)		
a. Manual CRIS (Trip Buttons)	Not Applicable	Not Applicable
b. Manual SIAS (Trip Buttons)	Not Applicable	Not Applicable
c. Airborne Radiation		
i. Particulate/Iodine	$\leq 5.7 \times 10^4$ cpm**	$\leq 6.0 \times 10^4$ cpm**
ii. Gaseous	$\leq 3.8 \times 10^2$ cpm**	$\leq 4.0 \times 10^2$ cpm**
d. Automatic Actuation Logic	Not Applicable	Not Applicable
10. TOXIC GAS ISOLATION (TGIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Chlorine - High	$\leq$ 14.3 ppm	$\leq$ 15.0 ppm
c. Ammonia - High	$\leq$ 97 ppm	$\leq$ 100 ppm
d. Butane/Propane - High	$\leq$ 193 ppm	$\leq$ 200 ppm
e. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. SAFETY INJECTION (SIAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3, 4
b. Containment Pressure - High	S	(6)	M	1, 2, 3
c. Pressurizer Pressure - Low	S	(6)	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3, 4
2. CONTAINMENT SPRAY (CSAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3
b. Containment Pressure -- High - High	S	(6)	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3
3. CONTAINMENT ISOLATION (CIAS)				
a. Manual CIAS (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3, 4
b. Manual SIAS (Trip Buttons)(5)	N.A.	N.A.	(6)	1, 2, 3, 4
c. Containment Pressure - High	S	(6)	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3, 4
4. MAIN STEAM ISOLATION (MSIS)				
a. Manual (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3
b. Steam Generator Pressure - Low	S	(6)	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3
5. RECIRCULATION (RAS)				
a. Refueling Water Storage Tank - Low	S	R	M	1, 2, 3, 4
b. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3, 4
6. CONTAINMENT COOLING (CCAS)				
a. Manual CCAS (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3, 4
b. Manual SIAS (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3, 4
c. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3, 4

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
7. LOSS OF POWER (LOV)				
a. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage and Degraded Voltage)	S	(6)	(6)	1, 2, 3, 4
8. EMERGENCY FEEDWATER (EFAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	(6)	1, 2, 3
b. SG Level (A/B)-Low and ΔP (A/B) - High	S	(6)	M	1, 2, 3
c. SG Level (A/B) - Low and No Pressure - Low Trip (A/B)	S	(6)	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)(3), SA(4)	1, 2, 3
9. CONTROL ROOM ISOLATION (CRIS)				
a. Manual CRIS (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Manual SIAS (Trip Buttons)	N.A.	N.A.	R	N.A.
c. Airborne Radiation				
i. Particulate/Iodine	S	R	M	All
ii. Gaseous	S	R	M	All
d. Automatic Actuation Logic	N.A.	N.A.	R(3)	All
10. TOXIC GAS ISOLATION (TGIS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Chlorine - High	S	R	M	All
c. Ammonia - High	S	R	M	All
d. Butane/Propane - High	S	R	M	All
e. Automatic Actuation Logic	N.A.	N.A.	R (3)	All

TABLE 3.3-9

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	CHANNEL RANGE	MINIMUM CHANNELS OPERABLE
1. Log Power Level	*	10^{-8} - 200%	1
2. Reactor Coolant Cold Leg Temperature	#	0-700°F(a)	1
3. Pressurizer Pressure	*	0-3000 psia	1
4. Pressurizer Level	*	0-100%	1
5. Steam Generator Pressure	*	0-1200 psia	1/steam generator
6. Steam Generator Level	*	0-100%	1/steam generator
7. Source Range Neutron Flux	*	10^{-1}-10^{5} cps	1
8. Condenser Vacuum	*	0-5" Hg	1
9. Volume Control Tank Level	*	0-100%	1
10. Letdown Heat Exchanger Pressure	*	0-600 psig	1
11. Letdown Heat Exchanger Temperature	*	0-200°F	1
12. Boric Acid Makeup Tank Level	*	0-100%	1
13. Condensate Storage Tank Level	*	0-100%	1
14. Reactor Coolant Hot Leg Temperature	#	0-700°F(b)	1
15. Pressurizer Pressure - Low Range	#	0-1600 psia	1
16. Pressurizer Pressure - High Range	#	1500-2500 psia	1
17. Pressurizer Level	#	0-100%	1
18. Steam Generator Pressure	#	0-1050 psia	1/steam generator
19. Steam Generator Level	#	0-100%	1/steam generator

*Panel L042
#Panel L411

(a) 0-600°F until completion of DCP 6604
(b) 190-625°F until completion of DCP 6604

Revised

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Log Power Level	M	(1)
2. Reactor Coolant Cold Leg Temperature	M	(1)
3. Pressurizer Pressure	M	(1)
4. Pressurizer Level	M	(1)
5. Steam Generator Level	M	(1)
6. Steam Generator Pressure	M	(1)
7. Source Range Neutron Flux	M	(1)
8. Condenser Vacuum	M	(1)
9. Volume Control Tank Level	M	(1)
10. Letdown Heat Exchanger Pressure	M	(1)
11. Letdown Heat Exchanger Temperature	M	(1)
12. Boric Acid Makeup Tank Level	M	(1)
13. Condensate Storage Tank Level	M	(1)
14. Reactor Coolant Hot Leg Temperature	M	(1)
15. Pressurizer Pressure - Low Range	M	(1)
16. Pressurizer Pressure - High Range	M	(1)
17. Pressurizer Level	M	(1)
18. Steam Generator Pressure	M	(1)
19. Steam Generator Level	M	(1)

TABLE NOTATION

(1) At least once per Refueling Interval.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 88 TO FACILITY OPERATING LICENSE NO. NPF-10

AND AMENDMENT NO. 78 TO FACILITY OPERATING LICENSE NO. NPF-15

SOUTHERN CALIFORNIA EDISON COMPANY

SAN DIEGO GAS AND ELECTRIC COMPANY

THE CITY OF RIVERSIDE, CALIFORNIA

THE CITY OF ANAHEIM, CALIFORNIA

SAN ONOFRE NUCLEAR GENERATING STATION, UNIT NOS. 2 AND 3

DOCKET NOS. 50-361 AND 50-362

1.0 INTRODUCTION

By letter dated January 8, 1990, Southern California Edison Company, et al. (the licensee), requested changes to the Technical Specifications for Facility Operating License Nos. NPF-10 and NPF-15 that authorize operation of San Onofre Nuclear Generating Station Unit Nos. 2 and 3 in San Diego County, California. These requests were designated in PCN 275, PCN 276, and PCN 280.

At present San Onofre Units 2 and 3 are operating on a 24-month fuel cycle. To avoid an 18-month refueling surveillance "outage" and support a 24-month fuel cycle, Technical Specification changes PCN 275, PCN 276, and PCN 280 propose to extend the refueling surveillance test interval from 18 months to 24 months for Reactor Protection (RPS), Engineered Safety Features Actuation (ESFAS) and Remote Shutdown Monitoring Instrumentation (RSI). The proposed changes cover the 18-month surveillances which cannot be performed while either unit is at power. Both Units 2 and 3 will have to shut down to perform an 18-month surveillance outage unless the current Technical Specifications are extended.

The licensee responded to the staff's verbal request to provide additional information. This information was provided by letters dated March 12, March 19, and May 2, 1990. Additionally, the licensee met with the staff on March 6, 1990 to discuss the proposed amendments and to address any staff concerns. This information did not change the proposed no significant hazards consideration determination that was previously noticed.

2.0 EVALUATION

2.1 PCN 275 - Reactor Protection System (RPS)

2.1.1 Discussion

The proposed change would revise the San Onofre Unit 2 and 3 Technical Specifications 3/4.3.10 "Reactor Protective Instrumentation" surveillance requirements to increase the interval for surveillance tests, currently scheduled every 18 months to each refueling outage (nominally 24 months to a maximum of 30 months (25%)). The RPS instrumentation provides the means of monitoring plant safety parameters and ensuring that these limits are not exceeded during anticipated operational occurrences. The Technical Specification defines the limits as Departure From Nucleate Boiling, Peak Linear Heat Rate and Reactor Coolant System Pressure. The first two limits protect the cladding boundary and the last limit protects the RCS boundary. In addition, the RPS aids the ESFAS in the mitigation of accidents by ensuring the reactor is shutdown.

The licensee provided a methodology to evaluate the extension of the RPS functional units surveillance interval. Essentially, this involved a review of surveillance testing and surveillance/maintenance history data. The evaluation provided a data base of "as found" and "as left" values. This data was utilized in a plant-specific instrument drift study for the various instrument types used at San Onofre Units 2 and 3. Instrument setpoints were then recalculated for the extended interval using historical drift values and compared with the present San Onofre Unit 2 and 3 setpoint calculations.

A comparison between on-line and refueling interval surveillances was performed for RPS instruments. The on-line surveillances were reviewed to determine to what extent this data might overlap the surveillances performed during refueling. The on-line surveillance review was also performed to ensure that all operability problems with RPS instrumentation were being identified in a timely manner, and to determine the significance of 18-month surveillances in maintaining instrument operability. Also, a review of the refueling surveillance test data and corrective maintenance history was performed by the licensee on instruments affected by the proposed extended surveillance interval.

Several factors were involved during the review of the surveillance history and maintenance programs. First, it must be determined if the existing surveillances are identifying equipment problems that affect operability of the instrument. Also, a corrective maintenance review needs to confirm that problems affecting operability are being identified prior to the performance of the instrument surveillances. A surveillance interval might be increased if corrective maintenance identifies operability problems and the surveillance calibration history does not include failures that affect instrument operability.

The surveillances performed on the RPS instrumentation included 18-month, quarterly, monthly, daily and per-shift calibrations. The 18-month, monthly channel functional tests and per-shift channel checks are also performed. The channel functional test confirms the operability of the instrument loop, except for the transmitter. The per-shift channel check provides a means to establish loop and transmitter operability.

Channel checks and channel functional tests may not reveal minor changes in transmitter calibration while the unit is on line. To confirm that instrument drift would be acceptable over a 24-month fuel cycle, the licensee performed an analysis of the drift characteristics of pressure, differential pressure, and temperature transmitters. A plant-specific review of the long term drift experienced over an 18-(maximum 22.5) month fuel cycle was statistically adjusted to reflect the maximum drift expected over a 24-month fuel cycle at a 95% probability and at a 95% confidence level. These values were then compared to the values utilized in the plant protection system setpoint and core protection calculator uncertainty calculations for an 18-month fuel cycle.

The transmitter drift was determined by subtracting the "as left" calibration data from the "as found" calibration data. Although each instrument is calculated at five separate calibration points, only the maximum drift value of the five points was selected. This value was converted to percent of span and divided by the interval between each calibration. After the drift for each transmitter was determined, the data was grouped by model and by process. Only the data with intervals of less than 22.5 months but greater than 100 days were evaluated. This was done to eliminate data points that were greater than the allowable fuel cycle, indicating that surveillance data was missing from the raw data, or calibration data that was most likely a result of instrument repair and not instrument drift. Any data point that differed significantly from the sample was evaluated and removed from the data base as appropriate. When the instrument data for a particular instrument population was large, the data was evaluated to ensure that the data could be represented by a normal distribution.

Once the maximum drift was known, comparisons to the drift values used in the San Onofre Unit 2 and 3 setpoint calculations were made. The values of long term drift referenced in the setpoint calculations are a result of statistically combining the drift value with other uncertainties to arrive at a value that ensures actuation of equipment in accordance with the trip setpoint and allowable values. The values referenced in the setpoint calculations are based on a maximum 22.5-month surveillance interval (18 months +25%). If the as-found drift values are less than these values when extrapolated to a 30-month interval, no revision to the Reactor Protection System setpoint calculations would be required. However, the experienced 95/95 30-month drift intervals for the RPS instrumentation were not bounded by the existing drift allowables. The RPS setpoints include assumptions for transmitter drift which are a function of the calibration interval. A review of the RPS setpoint calculations was required. The licensee determined that to extend the surveillance interval to 30-months, the RPS setpoints would have to be revised to account for the larger drift associated with a 30-month surveillance interval.

The larger values for instrument drift when incorporated into the setpoint calculations resulted in more restrictive values for plant operations. Since more restrictive setpoints may result in unnecessary reactor trips, a review of the setpoint calculations and safety analysis setpoints was performed. This resulted in the safety analysis setpoints being revised for the following:

High pressurizer pressure
High Containment Pressure
Low Steam Generator Water Level

Trip setpoints were also revised for the following functional units (numbered as shown below from TS Table 2.2.1):

2. Linear Power High
3. Logarithmic Power Level-High
4. Pressurizer Pressure High
5. Pressurizer Pressure Low
6. Containment Pressure High
7. Steam Generator Pressure Low
8. Steam Generator Level Low
11. Reactor Coolant Flow Low
12. Steam Generator Level High

Although safety analyses and trip setpoints were revised, no changes to the safety limits were made, nor were the conclusions of the UFSAR changed.

The licensee submittal also revised the calibration tolerance of the RPS bistable trip units. This change was not a result of extending surveillance intervals but a result of the setpoint/calibration procedure review and a discrepancy found between the surveillance procedure and the setpoint calculations. The revision to the bistable trip units calibration tolerance was included in all setpoint calculations. Additionally, trip setpoint calculations for low pressurizer trip were revised to reflect more realistic containment environmental conditions (5 PSIG and 250 degrees F). Another change not related to surveillance interval extension discovered during the evaluation of surveillance records was that the response time for high logarithmic power should be .400 seconds instead of .450. The response time of .450 seconds includes the response time of the detector which is not included in the periodic response time surveillance performed by the licensee. To improve the operating margin for High Linear Power, the nuclear calorimetric calibration tolerance will be administratively controlled at 1% by the licensee.

2.1.2 PCN 275 RPS Summary

Extending the surveillance interval for RPS instrumentation from 18 to 24 months (maximum 30) results in instrument drift outside the current allowables as shown in TS table 2.2-1. The licensee performed an evaluation of all RPS instrumentation for which an outage calibration interval was requested. The evaluation consisted of an analysis of all Preventive Maintenance (PM) surveillances, a PM history review of all affected instruments (including, in some cases, the same model instrument but used in a different system or process), a statistical review of instruments impacted by drift, a review of the safety analysis and a review of the setpoint calculations. The results of the review found that the experienced values of drift for RPS instrumentation exceeded the existing RPS allowables when extrapolated to a 30-month calibration interval. As a result, trip and safety analysis setpoints were revised based on the licensee's long term drift data for RPS transmitters. These revisions to the trip setpoint calculations preserve the margin of safety while maintaining an adequate operating margin. No safety limits were revised to support the extension of surveillance intervals. Additionally, the licensee determined, based on a review of PM history, that instrument problems associated with operability were detectable by plant personnel during shift channel checks or routine monitoring of plant parameters. The PM history review did not identify any correlation between the number of failures and the interval of calibration.

2.2 PCN 280 Engineered Safety Features Actuation (ESFAS)

2.2.1 Discussion

The proposed change would revise the San Onofre Unit 2 and 3 TS Section 3/4.3.2 "ESFAS Instrumentation" to increase the interval for surveillance tests from 18 months to nominally 24 months (maximum 30 months). TS 3/4.3.2 provides instrumentation operability and surveillance requirements for ESFAS systems. The TS also ensure that the ESFAS senses accident-related parameters and actuates equipment that mitigates the consequences of accidents.

The methodology used by the licensee to evaluate the extension of ESFAS surveillances is essentially the same as that used for the RPS instrumentation (as described above). A comparative review of surveillance testing was performed to determine to what extent on-line testing encompassed that which is done during refueling outages. A review of surveillance test results and corrective maintenance history was performed on instruments being considered for surveillance interval extension. This review was done to determine what role 18-month surveillance testing played in maintaining instrument operability. A plant-specific instrument drift study was performed to determine the drift characteristics of pressure, differential pressure and temperature transmitters affected by a surveillance interval extension. Finally, a setpoint analysis was performed using the long term drift values determined by the drift study.

Technical Specification 3/4.3.2 Table 4.3-2 lists the following functional units (numbered as shown below) for ESFAS instrumentation:

1. Safety Injection
2. Containment Spray

3. Containment Isolation
4. Main Steam Isolation
5. Recirculation
6. Containment Cooling
7. Loss of Power
8. Emergency Feedwater
9. Control Room Isolation
10. Toxic Gas Isolation
11. Fuel Handling Isolation
12. Containment Purge Isolation

Table 4.3-2 lists the required surveillance frequency interval for the above functional units. No interval extension has been proposed for any part of functional unit 5. Functional units 1, 2, 3, 4, 6, and 8 have no 18-month channel check or channel calibration requirement for the automatic actuation logic surveillance and therefore that part of the TS functional unit is not being revised. Functional units 9, 10 and 11 can be tested at any time during the fuel cycle without plant shutdown and therefore no extension was requested. Finally, PCN 268 and 266 (which are not reviewed in this SE) address functional unit 12. (PCN 266 was approved on January 2, 1990 and PCN 268 was approved on February 26, 1990.)

Similar to the RPS evaluation, an analysis of the surveillances performed on ESFAS instrumentation was conducted by the licensee. This review was done to ensure that all instruments being considered for an interval extension are being monitored and that all operability problems are being identified. Also, the importance of the 18-month surveillance interval in maintaining operability was assessed. The surveillances performed on ESFAS instrumentation include 18-month calibration. The 18-month, bi-annual and monthly channel functional test and per-shift channel checks are also performed. The channel functional test demonstrates the operability of the loop except for the transmitter. The shift channel checks provide reasonable assurance of loop and transmitter operability.

The ESFAS instrumentation was also included in the drift study done by the licensee. The methodology was the same as that used for the RPS instrumentation. The experienced long-term drift was statistically adjusted to reflect the maximum drift expected over a fuel cycle (24 months +25%) at a 95% probability and a 95% confidence level. As with the RPS, the drift allowables derived from the instrument drift study were incorporated into the setpoint calculations. If the revised trip setpoint resulted in a reduced operating margin, the trip setpoint calculations and safety analysis setpoints were reviewed.

The following Safety Analysis Setpoints were revised:

High Containment Pressure
Low Steam Generator Water Level
High Steam Generator Delta Pressure

The following trip/actuation setpoints were also revised:

Low Pressurizer Pressure
Low Steam Generator Level
High Containment Pressure
High Steam Generator Delta Pressure
Low Steam Generator Pressure
High-High Containment Pressure

As with the RPS, safety analysis and trip setpoints were revised. However, no changes to the safety limits were made, nor were the conclusions of the UFSAR changed.

The methodology used for the instrument setpoint calculations is consistent with ANSI/ISA-67.04-1988, "Setpoints for Nuclear Safety Related Instrumentation in Nuclear Power Plants." The setpoint reanalysis for experienced 95/95 drift values included a revised trip bistable calibration tolerance from 5mv to 25mv. The low pressurizer trip setpoint was recalculated using revised values for containment environmental conditions for a small or large break LOCA in addition to increased values for transmitter drift and PPS bistable tolerances. This evaluation resulted in ESFAS trip and allowable value changes for the following functional units (numbered as shown) on TS 3/4.3-22 Table 3.3-4:

1. Safety Injection
2. Containment Spray
3. Containment Isolation
4. Main Steam Isolation
8. Emergency Feedwater

2.2.2 PCN 280 ESFAS Summary

The proposed changes increase the surveillance interval from 18 months to a refueling interval of nominally 24 months (maximum 30). The evaluation of ESFAS instrumentation consisted of a comparative analysis of all PM surveillances impacted by drift, a review of the safety analysis and setpoint calculations.

The PM history identified that instrument problems associated with operability are detectable by plant personnel during shift channel checks or monthly channel functional tests. The licensee stated that no instances involving repetitive failures have occurred, or instances involving redundant channels during the same time period. The licensee also stated that no surveillance problems were identified for the manual actuation circuits. The revised trip setpoints are based on experienced long term drift 95/95 values for ESFAS transmitters, revised assumptions and bistable tolerances. The referenced TS change verifies that the revised setpoints and response times will maintain the safety limits and maintain an adequate operating margin.

2.3 PCN 276 Remote Shutdown Instrumentation (RSI)

2.3.1 Discussion

The proposed change would revise TS 3/4.3.3.5, "RSI," to increase the current 18-month surveillance interval to each refueling, which has been defined as nominally 24 months (maximum 30 months). The RSI system provides operators the means to monitor the status of systems required to achieve either hot or cold shutdown. Table 4.3-6 specifies the mode and required frequency for the channel check and channel calibration of each RSI channel.

The channel check is performed at monthly intervals and the channel calibrations are performed every 18 months. As with ESFAS and RPS, the RSI TS include requirements to calibrate transmitters that are not readily accessible during power operations. To avoid a plant shutdown solely to perform instrument calibrations, an evaluation was performed by the licensee to determine if the surveillance intervals for the RSI could be extended. The evaluation performed by the licensee included a review of surveillance testing, an evaluation of surveillance and corrective maintenance history. The RSI was also included in the San Onofre instrument drift study. Unlike the ESFAS and RPS instrumentation, the RSI did not require a setpoint analysis. However, the RSI is used by the operator to implement the Abnormal Operating Instructions. A functional analysis was done to assess the effects of the experienced drift values on those instructions.

The analysis of the surveillance testing results of RSI was handled the same as that for RPS and ESFAS. A review was performed to ensure that any operability problems are being identified by the monthly channel checks and 18-month surveillances. Another purpose of the review was to determine to what extent the 18-month surveillances contribute to maintaining RSI operability. Next, the surveillance and maintenance history for the RSI was reviewed by the licensee to determine if failures affecting operability were identified and corrected before performing the surveillance. The surveillance results indicate that the monthly channel check is the primary method providing assurance of loop operability. The monthly check consists of a control room to shutdown panel instrumentation indication check. Analysis of the drift characteristics of the RSI was included in the San Onofre instrumentation drift study. As with RPS and ESFAS, the drift of pressure, differential pressure, and temperature transmitters was determined.

The plant-specific values of drift determined by the drift study were utilized for the RSI drift instead of generic data. The licensee stated that plant-specific drift data provides more conservative results.

Unlike the RPS and ESFAS systems (where Regulatory Guide 1.105 provides a basis for the use of 95/95 drift values) the RSI drift values are based on a best-estimate approach. The licensee stated that, because setpoints are not provided for the RSI and that RSI is used in conjunction with operator actions and the Abnormal Operating Instructions, a best-estimate value in this application is acceptable. The best estimate of instrument drift used the maximum value of drift for the five calibration points that was determined for each calibration interval. This value was then adjusted to arrive at an annual drift rate. The best-estimate calculation of drift was then found by dividing the absolute value of the "with" data point by the number of data points.

The revised drift allowances for the RSI were chosen to be consistent with the allowances used for similar instrumentation in the plant protection system (RSI, ESFAS). Although a best-estimate value was calculated for RSI, allowable values originally derived for similar instruments in ESFAS and RPS were used except for the following, which utilized a best estimate value:

RCS Cold Leg Temperature
Condenser Vacuum
BAMU Tank Level RCS
RCS Hot Leg Temperature
Pressurizer Level

A functional analysis was performed for the RSI to determine the impact of the revised drift allowances on the San Onofre Units 2 and 3 Abnormal Operating Instructions. The drift values for most of the RSI instrumentation were based on 95/95 values rather than best-estimate values. The drift allowables that were calculated for the RSI are more conservative than generic vendor data.

The experienced drift values were then used to calculate a total uncertainty value. This new uncertainty value was compared to the values given in the Abnormal Operating Instructions, and the impact of the new value on the ability of an operator to comply with the instructions given in the Abnormal Operating Instruction (SO23-13.2) was assessed. The allowable error given in each step of the Abnormal Operating Instruction was compared to the revised 30-month value. This comparison indicated that the RSI instrumentation would still perform its intended function as outlined in the Abnormal Operating Instruction.

2.3.2 PCN 276 RSI Summary

A functional analysis was performed for all RSI surveillances. To impart additional conservatism, 95/95 values rather than best-estimate values were used for most RSI instrument allowables. The 30-month drift values were incorporated into the RSI instrument uncertainty calculations. These were then compared to the allowable values referenced in procedure SO23-13.2. The licensee stated these comparisons confirmed that the operator has adequate information to maintain the unit in a hot shutdown condition, or to achieve cold shutdown. The licensee stated that the other surveillances (monthly channel checks) provide a high degree of assurance that the instruments are performing properly and the Abnormal Operating Instruction can be successfully implemented in post-accident situations.

The review of the surveillance testing confirmed that performance of the monthly checks provides a reasonable level of assurance of instrument operability. The results also support the conclusion that the importance of the calibration surveillance is generally to correct instrument drift. Surveillance and corrective maintenance history reviews verified that most instrumentation problems with the RSI instrumentation are being identified by the monthly channel checks. The information presented by the licensee did not indicate any correlation between the number of failures and the calibration intervals.

It should be noted that some RSI instrumentation was not subject to drift, and the surveillance and corrective maintenance history in conjunction with the functional analysis provided adequate basis for a surveillance extension.

2.4 Conclusion

The analyses performed by the licensee for each application (PCNs 275, 280 and 276) were all similar.

The proposed changes increase the surveillance intervals for RPS, ESFAS and RSI instrumentation from 18 months to 24 months with a maximum interval of 30 months (as allowed by the San Onofre Technical Specification 4.0.2). This extension has been proposed so that instrument surveillances calibration intervals will coincide with the San Onofre Unit 2 and 3 fuel cycle of 24 months (and would allow additional time through TS 4.0.2 for scheduling purposes as necessary).

To justify the surveillance extension to 24 months, all the PCNs provided results of a comparative analysis of PM surveillances, PM history review, and a statistical evaluation of drift. For both RPS and ESFAS a review of the trip setpoint calculations was conducted; for the RSI a functional analysis of the abnormal operating instructions was performed.

The PM history review performed by the licensee has verified to the staff that instrument problems associated with operability were detectable by plant personnel during either shift channel checks or monthly channel functional tests. The RPS, ESFAS and RSI instrumentation reviews found no repetitive failures or failures involving redundant channels during the same time period. The licensee documentation of the PM history/surveillance testing did not identify any correlation between the number of failures and the interval of calibration. The licensee stated that the analysis indicated that the 18-month surveillances were in most cases correcting instrument drift only and that instrument operability was being verified by the shift channel check and the monthly channel checks or functional tests. The staff believes that the findings of the surveillance and corrective maintenance analysis and history review supports the surveillance extension proposed by PCNs 275, 280 and 276.

Transmitter calibration was also investigated by the licensee for San Onofre Units 2 and 3. The drift characteristics of all RPS, ESFAS and RSI pressure, differential pressure and temperature transmitters were evaluated to determine if a surveillance interval extension was justified. The licensee chose to perform a plant-specific drift study instead of incorporating generic vendor data. The staff agrees with the licensee that this approach provides a more conservative value of instrument drift. This approach is consistent with earlier staff evaluations (CEOG Topical Report CEN-327 RPS/ESFAS "Extended Test Interval Evaluation" Supplement 1) and is consistent with a proposed amendment to ANSI/ISA-67.04-1988.

The licensee reviewed calibration test results for instruments affected by drift. In some cases, similar instrumentation in other systems was evaluated to increase the number of data points available for analysis. The experienced long term drift was statistically adjusted to reflect the maximum drift expected over a fuel cycle at a 95% probability and at a 95% confidence level for each model of transmitter referenced by PCNs 275, 276 and 280. The resulting values were then compared to the amount of long term drift incorporated into the analog setpoint and core protection calculator setpoint calculations. The drift study also included instrumentation related to the remote shutdown instrumentation system. The drift for these particular instruments was determined using a best-estimate methodology.

The licensee's calculations for setpoint drift for PCNs 275, 276 and 280 are carried separately for each type of transmitter and in some cases by process. For each transmitter type, calibration data from RPS, ESFAS and RSI instrumentation was gathered. From each transmitter, zero, one or several calibration periods are recorded. For each recorded calibration period, five calibration points are available. The drift was determined for each calibration period by taking the difference between the "as left" and the "as found" value for each of the five calibration points. The maximum of the absolute value of the five differences is identified, converted to a percent of span, and annualized to produce a single data point that represents the drift during that calibration period. A data base of the resulting drift valves were then used for a statistical analysis of the data.

Prior to the analysis, the data underwent editing in two stages. In the first stage, data points were removed from the data base if the time between calibrations was less that 100 days or longer than 22.5 months. The licensee stated that intervals of less than 100 represented a short-term problem (instrument failure) which was most likely discovered by operators during shift channel checks or by some other means. Also, data that had an interval greater than 22.5 months was eliminated from the data base. These points were eliminated by the licensee due to the fact that these intervals were beyond the maximum allowed by the Technical Specifications and indicates that a calibration data sheet was not recovered. In the second stage, data may be excluded from the data base if so suggested by the data rejection criterion. However, whereas a probability level of a =.01 is generally recommended for rejection of an outline, the licensee elected to use a value of a =.05, which the staff feels is not an appropriate value. Using a =.05 could lead to a rejection of valid points that would make the data spread smaller and lower the tolerance limit of the drift for instruments that require a 95/95 estimation. It should also be noted that the reference utilized by the utility suggests that a value of equal to a=.01 or less should be used.

Although the licensee treatment of outlines is not as conservative as would normally be accepted by the staff, the licensee's approach has several layers of conservatism which compensates for the lack of conservatism in the treatment of outlines. This conservatism is shown by:

A. The drift is taken as the maximum of five calculated values from the "as left," "as found" differences. The staff feels that the maximum drift clearly overstates the actual drift.

B. The licensee always recorded the drift in absolute value. This biases the calculated drift regardless of whether it is overstated or understated.

C. The 95/95 tolerance limit used by the licensee is two sided, where as a one-sided tolerance would have sufficed. The K factor from the table of coefficients for tolerance limits is larger than needed.

D. In the construction of least square fit to the drift data, the methodology assumes a linear relationship between time and drift. The licensee's experience, on the other hand, indicates this to be a conservative approach.

When the number of data points was sufficient, the data was tested for normality using the chi-square goodness of fit test. In the licensee's analysis all the data tested were shown to be normally distributed. In some cases, the number of data points available for a particular instrument were insufficient to confirm a normal distribution. The licensee stated that for these cases the data did not indicate a departure from a normal distribution. The staff agreed with this assessment.

Two methods were used to estimate the overall instrument drift. The first was a two-sided 95/95 tolerance limit for the proportion of population of transmitter drift data. For this estimate, the licensee elected to use a 95% two-sided tolerance limit, as referenced in the licensee's documentation, Appendix G. This approach assumes a linear relation between drift and time. The second measure of drift is the average of the absolute value of the drift, termed the best estimate of drift. The 95/95 tolerance limit was used by San Onofre for instruments related to the plant protection system (RPS,ESFAS). The best estimate of drift was utilized for remote shutdown instrumentation. This is consistent with Reg Guide 1.105 and is acceptable to the staff. The staff, after considering all aspects of the licensee's approach, finds the methodology used to determine instrument drift for the RPS, ESFAS and RSI to be acceptable.

Once the long-term drift characteristics were known, these values were incorporated into the San Onofre Unit 2 and 3 setpoint calculations. The RPS and ESFAS setpoints include assumptions for transmitter drift. The setpoint calculations for San Onofre were recalculated using the new 30-month experience drift values. In addition to the new values of drift incorporated into the setpoint calculations, revised containment environmental conditions were included in some calculations. The plant protection system bistable trip unit calibration tolerance was also revised from 5 to 25mv. This change corrected a discrepancy between the setpoint calculation and the calibration procedures. All Technical Specifications for response time were found to be acceptable except for high logarithmic power. Again this change was not a result of a surveillance extension but an administrative change to correct a discrepancy between the setpoint calculations and calibration procedures. Although trip setpoints were revised along with safety analysis setpoints, no changes to the safety analysis limits were made. The setpoint methodology used by the licensee is consistent with ANSI/ISA-67.04-1988, Regulatory Guide 1.105 and the core reload analysis calculation and is acceptable to the staff. The operating margin for the core protection calculators remain unchanged. The UFSAR Chapter 15 accident analysis conclusions were not revised as a result of these setpoint changes. The staff finds the change to the revised setpoint calculations, response times and calibration tolerances to be acceptable, and to support an increased calibration interval of 24 months.

For the Remote Shutdown Monitoring system, the impact of extending calibration intervals resulted in the licensee performing a functional analysis of the Abnormal Operating Instructions. The functional analysis was comprised of three parts: 1) assessment of instruments used to comply with remote shutdown monitoring system Technical Specifications; 2) review of plant procedures in regards to Technical Specifications; and 3) assessment of drift error on each step of the Abnormal Operating Instruction. Although the drift study utilized the best-estimate values for the remote shutdown monitoring instrumentation, the licensee elected to incorporate 95/95 values for most drift values used in the evaluation of the Abnormal Operating Instructions. The licensee stated that comparisons of the calculated uncertainties to the allowable uncertainties demonstrated that the operator has sufficiently accurate information to maintain the unit in a hot shutdown condition or to achieve cold shutdown from outside the control room. Based on staff review of the functional analysis, the staff agrees with the licensee conclusion that the functional analysis supports a calibration interval extension to 24 months for the RSI instrumentation.

Based on the above evaluation, the staff finds the proposed technical specification changes to the Reactor Protection System, Engineered Safety Features Actuation System and Remote Shutdown Monitoring System as referenced in PCN 275, 276 and 280 to be acceptable. However, the bases for the calibration extensions for RPS, ESFAS and RSI are based in part on the ability of the shift channel checks and monthly channel functional test to identify instrument operability problems in a timely manner. Any future SONGS submittal requesting an extension of the RPS, ESFAS and RSI monthly channel functional test must confirm that the bases for the above referenced 24-month calibration interval extension is not compromised.

Therefore, based upon the licensee's applications and supporting documentation, and the information presented above, the staff approves the proposed amendments as outlined in PCN 275, PCN 276, and PCN 280 to the San Onofre Nuclear Generating Station, Unit Nos. 2 and 3, Technical Specifications.

3.0 CONTACT WITH STATE OFFICIAL

The staff has advised the State of California of the proposed determination of no significant hazards consideration. No comments were received.

4.0 ENVIRONMENTAL CONSIDERATION

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

5.0 CONCLUSION

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

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