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SUBJECT: Forwards License Amend Request 92-05 to Licenses DPR-80 & DPR-82,revising TS 2.2.1,3/4.3.1 & 3/4.3.2 & bases to reflect Eagle 21 process protection sys upgrade & RTD bypass elimination.

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September 21, 1992

PG&E Letter No. DCL-92-203

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Re: Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
License Amendment Request 92-05
Eagle 21 Process Protection System Upgrade and Resistance Temperature Detector Bypass Elimination

Gentlemen:

Enclosed is an application for amendment to Facility Operating License Nos. DPR-80 and DPR-82. The enclosed license amendment request (LAR) proposes to revise Technical Specifications (TS) 2.2.1, 3/4.3.1, 3/4.3.2, and their associated Bases to reflect the Eagle 21 process protection system upgrade, elimination of the bypass manifolds for the reactor coolant system (RCS) resistance temperature detectors (RTDs), and associated enhancements. Because the NRC Staff considers an analog to digital conversion of a safety system to be an unreviewed safety question, NRC approval is required for both the proposed TS changes and the Eagle 21 upgrade. Equipment is scheduled to be installed during the sixth refueling outages (Spring of 1994 for Unit 1 and Fall of 1994 for Unit 2), and placed in service during Cycle 7 for each unit.

The Westinghouse Eagle 21 upgrade replaces the Westinghouse 7100 analog process protection equipment with digital equipment that will improve the reliability and availability of the Reactor Protection System. The Eagle 21 equipment is also designed to permit maintenance and testing of individual protection channels in the bypass mode at power. Other enhancements provided as part of the Eagle 21 upgrade include (1) a trip time delay feature designed to reduce the potential for unnecessary Steam Generator Water Level Low-Low reactor trips below 50 percent power, (2) a new steam line break logic designed to reduce the potential for spurious safety injections at low power, and (3) an increased Steam Generator Water Level High-High Turbine Trip setpoint to reduce the likelihood of spurious trips due to normal operating transients. To support the Eagle 21 load demands, PG&E will also replace the existing vital instrument power inverters with larger inverters. NRC approval of the larger inverters will be requested in a separate LAR.

The RTD bypass elimination modification involves removal of all RCS hot and cold leg bypass manifolds and associated piping and valves. Dual element RTDs will be installed in thermowells in the hot and cold legs to provide the necessary reactor coolant temperature information. This

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modification will result in reduced personnel radiation exposure, improved availability, and reduced maintenance.

PG&E plans to begin installation of equipment in March of 1994 during the Unit 1 sixth refueling outage. The installation and modification process will require significant time and effort during the outage. To ensure adequate time is available for detailed planning and coordination with other outage activities, PG&E requests that the NRC issue a license amendment authorizing the proposed changes by April 1993.

Sincerely,

Gregory M. Rueger

cc: Edgar Bailey, DHS
Ann P. Hodgdon
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CPUC (w/o enc.)
Diablo Distribution (w/o enc.)

Enclosures

5800S/85K/RLJ/220

ATTACHMENT A

EAGLE 21 PROCESS PROTECTION SYSTEM UPGRADE AND
RESISTANCE TEMPERATURE DETECTOR BYPASS ELIMINATION
DIABLO CANYON POWER PLANT UNITS 1 AND 2

A. DESCRIPTION OF AMENDMENT REQUEST

This License Amendment Request (LAR) proposes to revise Technical Specifications (TS) 2.2.1, 3/4.3.1, 3/4.3.2, and their associated Bases to reflect the Eagle 21 process protection system upgrade, Reactor Coolant System (RCS) Resistance Temperature Detector Bypass Elimination (RTDBE), and associated enhancements to be implemented during the sixth refueling outage for each unit (Spring of 1994 for Unit 1 and Fall of 1994 for Unit 2). Specifically, the following TS changes are proposed:

1. A definition for a digital CHANNEL FUNCTIONAL TEST would be added and ANALOG CHANNEL OPERATIONAL TEST would become CHANNEL OPERATIONAL TEST and apply to both analog and digital channels.

2. The allowable values of TS Tables 2.2-1 and 3.3-4 would be revised to reflect rack drift allowances associated with the removal of the Westinghouse 7100 analog process protection system and installation of the Eagle 21 digital process protection system.

3. The Low-Low Steam Generator Water Level entries of TS Tables 2.2-1, 3.3-1, 3.3-2, 4.3-1, 3.3-3, 3.3-4, 3.3-5, and 4.3-2 would be revised to reflect incorporation of the Trip Time Delay (TTD) feature.

4. The Overtemperature and Overpower ΔT entries of TS Tables 2.2-1, 4.3-1, and 3.3-2 would be revised to reflect RTDBE.

5. A new Steam Line Break (SLB) protection logic would be implemented that results in deletion of the Safety Injection (SI) and Steam Line Isolation on High Steam Line Flow coincident with P-12 Low-Low T_{avg} and Steam Line Flow coincident with Low Steam Line Pressure. SI on High Differential Pressure Between Steam Lines also would be deleted. SI and Steam Line Isolation on Low Steam Line Pressure and Steam Line Isolation on High Negative Steam Line Pressure Rate Coincident with P-11 Pressurizer Pressure would be added in place of the deleted functions (TS Tables 3.3-3, 3.3-4, 3.3-5, and 4.3-2).

6. Testing and Maintenance in the bypass condition would be permitted for those functions for which the Eagle 21 system has an installed bypass testing capability.

7. Reactor Trip and Engineered Safety Features Actuation System (ESFAS) allowable values would be implemented based on the Westinghouse Statistical Setpoint Methodology.

8. The Steam Generator Water Level High-High trip setpoint for Turbine Trip and Feedwater Isolation, TS Table 3.3-4, would be revised to increase the setpoint from $\leq$67 to $\leq$75 percent of narrow range instrument span.

Changes to the TS are shown in the marked-up pages in Attachment B.

Rec'd w/Ltr Dtd 9/21/92 # 9209300045

The NRC Staff has taken the position that an analog to digital conversion of a safety system is an unreviewed safety question, as defined in 10 CFR 50.59. Therefore, in addition to approval of the proposed TS changes, NRC approval is also required before the Eagle 21 microprocessor-based process protection system can be installed to replace the existing analog equipment. The Eagle 21 upgrade for Diablo Canyon is described and evaluated in WCAP-13423, "Topical Report, Diablo Canyon Units 1 and 2 Eagle 21 Microprocessor-Based Process Protection System," and WCAP-12813, Revision 1, "Summary Report, Eagle 21 Process Protection System Upgrade for Diablo Canyon Units 1 and 2."

B. BACKGROUND

The proposed TS changes reflect modifications and enhancements to the Reactor Protection System (RPS) that will improve that system's reliability and availability. The Eagle 21 upgrade replaces the Westinghouse 7100 analog process protection racks with digital technology equipment as a direct form, fit, and functional replacement. In addition to providing identical process protection features, microprocessor capabilities, including automatic surveillance testing, self calibration, and self diagnostics, are included in the Eagle 21 system. The capability to perform maintenance and testing in the bypass mode is included in the Eagle 21 upgrade.

The protection system setpoints processed through the Eagle 21 system have been revised to reflect the different rack accuracies and elimination of the analog comparator. The setpoint changes are listed in WCAP-11082, Revision 1, "Westinghouse Setpoint Methodology for Protection Systems."

The TTD feature is being implemented to reduce the potential for unnecessary Steam Generator Water Level Low-Low reactor trips below 50 percent power. This is accomplished by delaying the trip based upon the safety analysis acceptance criteria at the power level at which the Steam Generator Water Level Low-Low setpoint is reached, rather than initiating the trip at the time the setpoint is reached. The TTD concept was developed by the Westinghouse Owners Group (WOG) Trip Reduction Assessment Program (TRAP) and is documented in WCAP-11325-P-A, Revision 1, "Steam Generator Low Water Level Protection System Modifications to Reduce Feedwater-Related Trips." The WCAP concept was approved in a Safety Evaluation Report (SER) issued by the NRC Staff in January 1988. In the conceptual design, the TTD varies with power level and on whether one steam generator or multiple (more than one) steam generators are at the low-low setpoint.

RCS RTDBE provides benefits in three primary areas: reduced radiation exposure, improved availability, and reduced maintenance. The system piping within the RCS loop compartment creates a significant source of radiation exposure during maintenance. As with all piping systems, there is associated operability testing, periodic maintenance, and unexpected outages. The installation of fast response RTDs in the hot and cold legs of the RCS and the processing of the corresponding signals by the Eagle 21 digital system provide the necessary process signals for the RPS.

The new SLB protection logic is implemented to accommodate the removal of the steam flow signals and the comparison of steam line pressures. These Engineered Safety Feature (ESF) signals have historically been the source of inadvertent SI actuations. The new protection logic utilizes low pressure and high negative pressure rates of change setpoints in each steam line, without comparison between steam lines, to initiate mitigating actions for SLB scenarios. The Negative Steam Line Pressure Rate-High is also added to provide protection when Steam Line Pressure-Low SI is blocked in MODE 3. This new SLB logic has been used on all later vintage Westinghouse plants.

The RTDBE modification has been successfully implemented in approximately 15 Westinghouse plants to date. The Eagle 21 upgrade has been retrofitted in three Westinghouse plants and is the original RPS hardware in two recent plants.

The increase in the Steam Generator Water Level High-High Turbine Trip setpoint will increase the margin between the normal water level and the trip setpoint, which in turn will reduce the likelihood of spurious turbine trips due to normal operating transients.

C. HARDWARE MODIFICATIONS

This section describes the hardware and associated RPS modifications that are included in this LAR. The Westinghouse 7100 analog process protection racks are replaced with digital equipment (Eagle 21), the RTD bypass manifold piping is replaced with thermowell mounted RTDs, and a time delay feature is added to the steam generator low-low level reactor trip function. In addition to the Eagle 21 RPS upgrade, a number of Reactor Trip System (RTS) and ESFAS trip functions are replaced or modified.

1. Eagle 21 Process Protection System

The existing Westinghouse 7100 analog process protection equipment is being replaced with Westinghouse Eagle 21 digital equipment. The Eagle 21 equipment is installed in the existing process racks and interfaces with other plant systems in a manner identical to the existing analog equipment. The design maintains the existing field terminals so new cable pulls and splices external to the racks are minimized. All rack subassemblies are fully tested in a factory mock-up to assure proper fit and operation. All internal rack cabling is prefabricated and tested prior to installation.

The Eagle 21 microprocessor-based process protection system is a functional replacement for the existing analog process protection system, but includes additional channels and functions including the TTD, new SLB logic, and RTDBE.

The Eagle 21 process protection equipment is designed to permit any one channel to be tested and maintained at power in a bypassed mode. If a channel has been bypassed for any purpose, the bypass is continuously indicated in the control room, as required by applicable codes and standards. There is one bypass annunciator

with four inputs and reflash capability. The annunciator typewriter is used to determine which set has the bypass condition. The design includes multiple levels of security for bypassing a protection channel and lifted leads and jumpers are not required.

2. Resistance Temperature Detector Bypass Elimination

The RTDBE upgrade modification affects the measurement of the RCS hot leg and cold leg temperatures. Prior to the modification, the RCS hot leg coolant was sampled by three scoops in the reactor coolant piping and an average hot leg temperature for each loop was obtained by a single RTD mounted in the loop hot leg bypass manifold. The RCS cold leg temperature was measured by a single RTD mounted in the cold leg bypass manifold. This modification removes the hot and cold leg manifolds and all associated piping and valves. With the elimination of the hot leg bypass manifold, three hot leg dual element RTDs are installed in thermowells mounted in what was previously the bypass manifold scoops. One of the elements is active and the other is an installed spare. The RTDs are in a single plane, 120 degrees apart. For each loop, the three temperatures are electronically averaged in the Eagle 21 process protection system to produce an average hot leg temperature (T_{hot}) that accounts for the temperature streaming effects. The cold leg measurement on each loop is measured by a dual element RTD installed in a thermowell mounted in a new penetration nozzle at the discharge of the reactor coolant pump. The Eagle 21 process protection system averages the two RTD elements to represent the cold leg temperature (T_{cold}).

Two control room annunciators are provided to inform the operator of an RTD malfunction. An input to the system level "PPS Trouble" annunciator indicates that the Eagle 21 process protection system has determined that the T_{avg} group value for a coolant loop is set to POOR and that there are therefore only two good narrow range T_{hot} signals for the loop in question. A "PPS RTD Failure" annunciator indicates that the Eagle 21 process protection system has detected a cold leg or hot leg RTD failure. The annunciator typewriter indicates to the operator which protection set generated the alarm.

3. New Steam Line Break Protection

The new SLB logic is incorporated with the installation of the Eagle 21 digital system and modifies the Solid State Protection System (SSPS) for the ESFAS logic. This upgrade requires the deletion, retention, and addition of several functions. These changes are:

Functions Deleted:

SI and Steam Line Isolation on High Steam Line Flow coincident with P-12 Low-Low T_{avg}

SI and Steam Line Isolation on High Steam Line Flow coincident with Low Steam Line Pressure

SI on High Steam Line Differential Pressure

Functions Retained:

Low Pressurizer Pressure SI

All High Containment Pressure signals

Functions Added:

SI and Steam Line Isolation on Low Steam Line Pressure

Steam Line Isolation on Negative Steam Line Pressure Rate High coincident with P-11 Pressurizer Pressure

Four reactor trip annunciators are removed as a result of the deletion of the high steam line differential pressure logic and addition of the low steam line pressure logic. Annunciators and status lights are provided for the new SLB logic as follows:

a. A common reflashed annunciator and an individual trip status light are provided for each High Pressure Rate Comparator and for each Low Steam Line Pressure Comparator.

b. Annunciators (1 each) are provided for Negative Steam Line Pressure Rate High and Low Steam Line Pressure. These inform the operator that 2 out of 3 coincidence logic for a loop has been satisfied and that a Steam Line Isolation (High Steam Line Pressure Rate interlocked with Permissive P-11) or SI and Steam Line Isolation (Low Steam Line Pressure without Permissive P-11) has been actuated.

4. Trip Time Delay

The TTD functional upgrade is incorporated as part of the Eagle 21 process protection system Steam Generator Level Low-Low reactor trip.

The implementation of this function at DCPP differs in several ways from that of the conceptual design documented in WCAP-11325-P-A that received generic NRC approval. Specific differences are:

a. The design and all logic decisions are implemented in the Eagle 21 process protection system instead of the SSPS.

b. Only 2 steam generator level channels are represented in Protection Sets I and II, while 4 steam generator level channels are represented in Protection Sets III and IV. Therefore, the multiple steam generator affected time delays are programmed into the TTD logic for all Protection Sets, as

it is desirable to have all steam generator level channels operate with the same time delays. Consequently, the less restrictive (longer) time delays associated with the conceptual design for a single affected steam generator are not used at DCPP.

c. The conceptual design used Power Range Nuclear Flux as the power measurement into the TTD calculation. This input is replaced by RCS loop ΔT to eliminate the effect of the increased uncertainties associated with the nuclear flux channels at lower power levels.

d. The discrete analog timers of WCAP-11325-P-A are replaced by microprocessor-generated continuous time delays.

e. No new status lights are provided as part of the TTD upgrade, but a Steam Generator TTD Timer Actuated annunciator is provided to signify that the water level in at least one channel has dropped below the low-low Level setpoint and that the associated TTD time delay(s) has (have) started. The design is such that above 50 percent reactor power, when the TTD time delay is zero, the alarm will not be actuated.

f. The Eagle 21 system has been designed to allow the Narrow Range T_{hot} and T_{cold} RTD channels for Thermal Overpower and Overtemperature ΔT protection to be tested without disturbing the TTD channel. Thus, there is no need for the associated Steam Generator Level Low-Low channels to default to a zero time delay setpoint when the Thermal Overpower and Overtemperature ΔT channels are in test.

5. Steam Generator Water Level High-High Turbine Trip Setpoint

The revised Steam Generator High-High Level Turbine Trip setpoint is within the range of the Eagle 21 RPS. Therefore, no specific hardware modifications are required to achieve the increased setpoint.

D. JUSTIFICATION

The changes to the allowable values in TS Tables 2.2-1 and 3.3-4 are supported by Revision 1 of WCAP-11082, "Westinghouse Setpoint Methodology for Protection Systems." The methodology used for determining the allowable values for Eagle 21 is the same as that used by other Westinghouse plants which use the Westinghouse Setpoint Methodology. Specific terms in the methodology are hardware dependent and vary depending on plant specific hardware configurations. The previous allowable values were based on bounding generic limits and were not dependent on the hardware configuration of the plant. The improved allowable values associated with the Eagle 21 hardware are the result of changes in rack calibration, elimination of the analog rack comparator, rack drift, and measurement and test equipment accuracies.

The TTD modification is designed to impose a predetermined delay upon the reactor trip and auxiliary feedwater system actuation during less-than-limiting steam generator water level transients. Restoration of steam generator water level to above the low-low level trip setpoint, during the trip delay period, will avoid an unnecessary reactor trip. A series of applicable accident analyses are used to confirm the acceptability of the trip delays with respect to Standard Review Plan criteria. NRC review and approval of the conceptual design of the TTD enhancement are documented in Westinghouse WCAP-11325-P-A (Revision 1), "Steam Generator Low Water Level Protection System Modifications to Reduce Feedwater-Related Trips." The DCPP implementation of the TTD is functionally equivalent to the TVA Sequoyah implementation, which was reviewed and approved in a Safety Evaluation Report (Docket No. 50-327) dated May 16, 1990. The Sequoyah application and evaluation includes an Environmental Allowance Modifier (EAM). DCPP does not propose to include an EAM.

The elimination of the RCS RTD bypass manifold at DCPP is consistent with the RTDBE performed on numerous Westinghouse-designed plants. The ability to obtain narrow range RCS temperature measurements is maintained by installing fast response RTDs in thermowells in the hot leg penetrations where the bypass manifolds and scoops are currently attached. A new RTD is located in each cold leg at the discharge of the reactor coolant pump. The existing cold leg RTD bypass penetration nozzles are capped and new penetrations for Loops 1, 2, 3, and 4 are installed for the RTD thermowells. The cold leg temperature is used directly as an average of the two cold leg RTDs, while the three hot leg RTDs are electronically averaged by the Eagle 21 system to account for temperature streaming. This averaged value is used as the RCS hot leg temperature. The Overtemperature and Overpower ΔT changes made are consistent with the revised Eagle 21 setpoint methodology (Westinghouse WCAP-11082, Revision 1), and supported by the FSAR Update accident reanalyses to accommodate the increase in Overtemperature and Overpower ΔT channel response time from 6 to 7 seconds.

The new SLB protection is supported by the non-loss-of-coolant accident (LOCA) analyses that model the protection system logic that leads to SI, Feedwater Isolation, and Steam Line Isolation when analyzing excessive cooldown events. The old and new SLB protection differ in the logic that leads to the actuation of these safety functions. In order to support the upgrade of the SLB protection from old to new, Westinghouse analyzed and evaluated the impact of this change on affected licensing basis non-LOCA transients.

PG&E has previously incorporated Surveillance Testing Interval (STI) and Allowed Outage Time (AOT) enhancements documented in Westinghouse WCAP-10271-P-A, Supplements 1 and 2, "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Reactor Protection Instrumentation System," and "Evaluation of Surveillance Frequencies and Out-of-Service Times for the Engineered Safety Features Actuation System." The evaluation presented in these WCAPs indicates that RPS reliability remains high with the proposed changes. Additionally, plant safety is maintained or improved, plant availability is improved, and the burden to the plant caused by TS-required surveillance tests is significantly reduced. Testing in bypass, which was generically approved by the NRC, was not incorporated in the previous amendments as the capability did not

exist in the Westinghouse 7100 system as configured at DCPP. This capability is being included in the Eagle 21 process protection system.

PG&E recognizes that the WCAP-10271 evaluations were based on analog process protection systems. PG&E has determined that replacement of the Westinghouse 7100 analog process protection equipment with Eagle 21 digital process protection equipment, which is at least as reliable as the analog equipment, does not invalidate the conclusions drawn in WCAP-10271 and its supplements.

Reliability studies have been performed on both the Eagle 21 process protection system and the Houston Lighting and Power Company (HL&P) (Docket Nos. 50-498 and 50-499) Qualified Display Processing System (QDPS) used at the South Texas Project, which has a high degree of component commonality with Eagle 21. In addition, actual operating mean time between failure (MTBF) data from the QDPS has shown that microprocessor-based equipment is exceeding design goals. The following information on the Eagle 21 system features and the reliability studies and actual operating history provides more details regarding channel and system reliability.

From the results of the reliability/availability assessment of the Eagle 21 and equivalent process protection systems, it has been determined that the Eagle 21 digital system availability is equivalent to the analog system availability even when no credit is taken for the fail-safe design principles, redundancy, automatic surveillance testing, self-calibration, and self-diagnostic features of the Eagle 21 process protection system. If full credit were to be given to the capabilities that exist for the Eagle 21, such as the self-diagnostic features including the electrically programmable read-only memory (EPROM) checksums, random access memory (RAM) checks, math coprocessor checks, and loop cycle time checks, they would further improve system availability. Furthermore, if credit were to be given to the redundancy, automatic surveillance testing, and self-calibration capabilities, there would be an additional improvement in system availability. Items such as decreasing the impact on system accuracies because of drifting signal loops being corrected by the Eagle 21 self-calibration feature or decreasing system downtime because of the automatic surveillance/self-diagnostic features will also have a positive impact on system availability. The Man-Machine Interface (MMI) provided with Eagle 21 will significantly reduce the amount of technician time required for maintenance and troubleshooting of the system. By using the MMI, instrument technician and engineering time needed to perform and review the quarterly functional tests will be significantly reduced over that required for the present equipment.

To permit a reliability comparison between the analog and digital systems, actual plant operating data was obtained from the South Texas Project QDPS. Prior to beginning evaluation of the data, an evaluation of the design similarities between the Eagle 21 and the QDPS systems was performed. This review determined that the Eagle 21 system is very similar in design to the South Texas Project QDPS. (Many of the Eagle 21 components are identical to those used in the QDPS.) A review of the South Texas Project QDPS reliability study was conducted for NRC by the Idaho National Engineering Laboratory. No methodology errors were noted as part of the review. In this study, expected MTBFs were postulated for the digital instrumentation channels using data obtained from the Printed

Circuit board vendors and compared with expected analog channel MTBFs. The South Texas Project QDPS data verified that the actual MTBF for the key components in the system far exceeds the postulated expected MTBF for the components. These results support the higher availability estimate of the implemented digital channel compared with a hypothetical analog counterpart. Additionally, the NRC staff concluded "... the QDPS provides a highly reliable system for its application at the South Texas Project and that its assessed reliability is acceptable." Based on these assessments, it was determined that because of the similarity in design between the QDPS and the Eagle 21 process systems, the conclusions reached for the QDPS may be applied to the Eagle 21 system.

Taking into account the information presented regarding the system design features and the QDPS digital process system data evaluated, the following conclusions can be reached:

1. The results of the availability assessment of the Eagle 21 and the equivalent analog process protection system demonstrate that the Eagle 21 digital system is at least as reliable as the present analog technologies.

2. If a more detailed analysis were to be performed incorporating the automatic surveillance test, redundancy, and self-test, self-calibration, and self-diagnostics features of the Eagle 21 system, predicted system availability would be further improved.

3. With the incorporation of the self-test, self-calibration, self-diagnostic, and automatic surveillance testing features, operator interface with the system is minimized, resulting in decreased system downtime and improved system accuracy.

4. Actual system MTBFs for a digital system far exceed the expected MTBFs derived from system design data.

Based on the results of these reliability studies, it is concluded that the quarterly STIs, the 6-hour time limit for an inoperable channel to be maintained in an untripped condition, and the extended AOTs for testing and maintenance that are currently contained in the DCPP TS can be maintained.

A Verification and Validation (V&V) program based on ANSI/IEEE-ANS-7-4.3.2, 1982, "Application Criteria for Programmable Digital Computer Systems in Safety Systems of Nuclear Power Generating Stations," was established for the Eagle 21 upgrade as defined in WCAP-13423, "Topical Report, Diablo Canyon Units 1 and 2 Eagle 21 Microprocessor-Based Process Protection System." The V&V program results are provided in WCAP-12934, "Diablo Canyon Eagle 21 Process Protection System Replacement Hardware Verification and Validation Report."

An evaluation of the impact of increasing the Steam Generator High-High Water Level Trip setpoint has been performed. The current setpoint value is 67 percent narrow range span (NRS). This evaluation shows that a safety analysis setpoint limit as high as 100 percent NRS is acceptable. However, Westinghouse engineering evaluations have determined that 82 percent NRS is the highest trip setpoint (excluding instrument errors) that is acceptable for Model 51 steam generators. Level measurement

above 82 percent at rated steam flow is unreliable and could result in excessive moisture carryover to the turbine. When instrument uncertainty is included, the nominal high level trip setpoint is therefore required to be less than or equal to 75 percent NRS. By increasing the margin between the normal steam generator water level and the trip setpoint, the likelihood of spurious trips due to transient deviations from the normal programmed water level is reduced and plant safety is maintained.

E. SAFETY EVALUATION

This section documents the basis for concluding that the changes to DCPP Units 1 and 2 described in this LAR do not constitute an unreviewed safety question based on the requirements and definitions delineated in 10 CFR 50.59(a)(2). The section organization follows that previously used in Section C, "Hardware Modifications."

1. Eagle 21 Process Protection System

The Eagle 21 process protection system has been designed and tested to satisfy all regulatory requirements specified in applicable criteria documents. The most significant Instrumentation and Control system regulatory criteria are evaluated and summarized below.

a. Single Failure Criterion

The Eagle 21 process protection system is designed to provide two, three or four instrumentation channels and outputs to two logic actuation trains for the RTS and ESFAS. Each rack set contains multiple processors (Set 1 and 2 - four processors; Set 3 and 4 - two processors). These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent a required protective system action. This implementation is consistent with the Westinghouse 7100 system that is being replaced.

b. Channel Independence

Within the Eagle 21 process protection system, there are four separate and independent rack sets. Channels that provide signals for the same protective function are each located in different rack sets ensuring that they will be independent and physically separated. Since all equipment within any rack is associated with a single Protection Channel Set, there is no requirement for separation of wiring and components within the rack. This implementation is consistent with the design of the analog system that is being replaced.

c. Equipment Qualification

The Westinghouse Equipment Qualification (EQ) test program demonstrated the Eagle 21 process protection equipment is capable of performing its designated safety-related functions

under all environmental and seismic conditions applicable to DCPP. The EQ test program is documented in WCAPs-8587 (Non-Proprietary) and -8687 (Proprietary), "Environmental and Seismic Qualification."

d. Noise, Fault, Surge Withstand Capability, and Radio Frequency Interference

The Noise, Fault, Surge Withstand Capability, and Radio Frequency Interference test program performed by Westinghouse demonstrated that the Eagle 21 process protection equipment is capable of performing its designated safety-related functions when subjected to these specified conditions. The Radio Frequency Interference test program is documented in WCAPs-11733 (Proprietary) and -11896 (Non-Proprietary), "Noise, Fault, Surge, and Radio Frequency Interference Test Report."

e. Control and Protection System Interaction

The Eagle 21 process protection system functions completely independently from the control systems. Its operation in protecting the plant from unsafe conditions is not affected by any fault or malfunction in the control system.

The transmission of signals from the Eagle 21 process protection system to the control systems is through isolation devices that are classified as part of the protection system. No credible fault at the output of an isolation device can prevent the associated Eagle 21 protection system from meeting the minimum performance requirements specified in the design bases.

Consideration must be given to possible protection channel failures that can both prevent a particular trip signal from that channel and cause the control system to drive the plant toward the unsafe condition for which the particular trip signal is needed. In each case where this is possible, either four protection channels have been provided and a 2 out of 4 logic is used to ensure the plant remains fully protected even when degraded by a second random failure, or a diverse means for providing a reactor trip is available. The exception to this is the Steam Generator Water Level Low-Low protective function, which relies on 2-out-of-3 logic and a control system Median Signal Selector (MSS). The MSS was previously approved by the NRC for use at DCPP in License Amendments 56 and 55, dated July 12, 1990. The use of a control system MSS prevents any protection system failure from causing a control system reaction resulting in a need for subsequent protective action. The reliability of the MSS is commensurate with that of the process protection system. The use of the MSS with the Eagle 21 digital system is identical to its use with the analog system that is being replaced.

f. Capability for Test and Calibration

The Eagle 21 process protection system performs automatic surveillance testing of the digital process protection racks through an MMI. Each channel is fully testable via the MMI. Interruption of the bistable output to the logic circuitry for any reason causes that portion of the logic to be actuated and gives a channel trip alarm and channel status light in the control room.

The Eagle 21 process protection system provides for continuous on-line self-calibration of analog input signals. If necessary, the system automatically compensates gain and offset coefficients to eliminate any errors that have been introduced.

g. Channel Bypass

The Eagle 21 process protection system equipment is designed to permit any one channel to be tested and maintained during power operation without initiating a protective action at the system level. Each channel has the capability to be tested and maintained in the bypass condition. During such operation, the process protection system does not satisfy the single failure criterion.

If a channel has been bypassed for any purpose, the condition is continuously indicated in the control room. There is one bypass annunciator with four inputs and reflash capability. The annunciator typewriter is used to indicate to the operator which channel set has the bypass condition. The design provides multiple levels of security, including password protection, for bypassing a protection channel.

In the SERs for Topical Report WCAP-10271 and its Supplements, testing in bypass was approved for all of the functions implemented in the Eagle 21 process protection system upgrade at DCPP, subject to verification that there was an installed hardware capability for testing in bypass. As stated by the NRC in the safety evaluation:

> Testing of the RPS analog channels in the bypassed condition by use of temporary jumpers or by lifting leads is not acceptable. The chance of personnel errors leaving a number of channels in the bypassed condition would be too large for the routine use of such methods. Therefore, licensees choosing this option to perform routine channel testing in the bypass mode should ensure that the plant design allows testing in bypass without lifting leads or installing temporary jumpers. The staff's acceptance of this option is contingent on confirmation of this capability.

The Eagle 21 design does provide the necessary capability to test without lifting leads or installing temporary jumpers and provides the "Indication of Bypasses" in the control room that

is required by IEEE 279-1971, paragraph 4.13. PG&E therefore intends to implement routine testing in bypass on all channels in the Eagle 21 digital system upgrade. However, the capability and acceptability of testing in trip will be maintained.

h. Access to Setpoint Adjustments

The Eagle 21 design provides for multiple levels of security for access to setpoint and tuning constant adjustments.

i. Time Response

The Eagle 21 digital electronics has a signal processing delay that is generally longer than the analog electronics it replaces. For the RTS and ESFAS, the time response of the Eagle 21 process protection system is less than the value assumed in the safety analyses for the analog system.

The increase in Wide Range RCS Pressure time response from 0.4 seconds to 0.65 seconds has an impact on the Low Temperature Overpressure Protection System (LTOPS) setpoints and/or Power Operated Relief Valve (PORV) maximum allowable stroke time. The additional delay will cause RCS pressure to rise an additional 5 psi in the limiting transient case (an inadvertent full throttle start of one centrifugal charging pump into a water solid RCS with letdown isolated) prior to LTOPS actuation. The current pressure setpoint in the DCPP LTOPS TS 3.4.9.3 is $\leq$ 450 psig. It is not proposed to change this setpoint and the impact of the Eagle 21 additional 0.25 second delay, based on a Westinghouse sensitivity study, is to reduce the maximum allowable PORV stroke time from 6.0 to 5.5 seconds. DCPP procedures currently limit the maximum PORV stroke time to 3.5 seconds. There is therefore no adverse impact on the protection provided by the LTOPS due to the increased Eagle 21 system time response.

The above demonstrates that the Eagle 21 process protection system meets all regulatory and design basis requirements and is acceptable for use at DCPP as a replacement for the existing Westinghouse 7100 Analog process protection system.

2. Resistance Temperature Detector Bypass Elimination

Removal of the RTD bypass piping and installation of a modified temperature measurement system (fast response RTDs mounted in thermowells) does not affect the integrity of the RCS. This is due to the reactor coolant piping (pressure boundary component) modifications adhering to the ASME Code [Sections III (Class 1) and XI] and to the NRC General Design Criteria.

3. New Steam Line Break Protection

The new SLB protection modification to the SSPS is described in Section C.3. The evaluation of the changes to the safety analysis as a result of the new SLB protection functions is presented in Section E.6.

4. Trip Time Delay

The TTD modification in DCPP Units 1 and 2 is incorporated entirely within the Eagle 21 process protection system and is described in Section C.4 and the Safety Evaluation justifying this change is provided in Section E.6.

5. Steam Generator Level High-High Turbine Trip Setpoint

The Steam Generator High-High Level Trip setpoint change is incorporated entirely within the Eagle 21 Process Protection System and is described in Section C.5 and the Safety Evaluation justifying this change is provided in Section E.6.

6. Non-LOCA Safety Analyses and Evaluations

The functional upgrades to be included with the Eagle 21 process protection system upgrade are:

- Elimination of the RTD Bypass System
- New Steam Line Break Protection
- Trip Time Delay

The digital electronics feature of the Eagle 21 system does not impact the non-LOCA safety analyses because the time delays and uncertainties are not greater than those previously assumed for the analog system. However, the functional upgrades associated with implementation of Eagle 21 affect the protection system modeling, which was used in some of the non-LOCA safety analyses.

a. Elimination of the RTD Bypass System

The two potential impacts of the new reactor coolant temperature measurement system on the non-LOCA safety analyses are a result of the RTD uncertainty and the RTD system overall time response.

<u>RTD Uncertainty</u>

The safety analyses make explicit allowance for instrumentation errors in the reactor protection system setpoints. In addition, allowances are made for uncertainty in the initial conditions of RCS average temperature, pressure, and power. These allowances are applied explicitly for the non-DNB related events, and for the DNB events, the allowances are statistically combined into the design limit DNBR values,

consistent with the use of the Improved Thermal Design Procedure (ITDP). The ITDP methodology is documented in WCAP-8567.

The protection and control system parameters affected by the change from one hot leg RTD installed in a bypass manifold to three RTDs installed in thermowells in the reactor coolant loops are: the Overtemperature ΔT (OTDT), Overpower ΔT (OPDT), low RCS flow reactor trip functions, RCS average temperature measurements used for control board indication input to the rod control system, and the calculated value of RCS flow uncertainty. System uncertainty calculations were performed for these parameters to determine the impact of the RTD system change. The results indicated that sufficient allowance has been made in the reactor protection system setpoints and initial condition uncertainties in the current licensing basis safety analyses.

RTD Response Time

Currently, the overall response time assumed in the safety analyses is 6.0 seconds. Following the RTDBE at DCPP, the overall response time is not expected to increase above this value. However, for conservatism, the overall response time is assumed to increase to 7.0 seconds. The increased RTD response time assumption results in longer delays from the time when fluid conditions in the RCS require an OTDT or OPDT reactor trip until a trip signal is actually generated.

The safety analyses for which an OTDT and OPDT trip occurred in the current analyses are RCCA Bank Withdrawal at Power (FSAR Update 15.2.2), Loss of External Electrical Load and/or Turbine Trip (FSAR Update 15.2.7), Steam Line Break Core Response at Power [documented in the Boron Injection Tank (BIT) elimination study report, WCAP-11938, Volumes 1 and 2, "BIT Elimination Study for Diablo Canyon Units 1 and 2"] and Steam Line Break Mass/Energy Releases for Outside Containment EQ (documented in the BIT elimination LAR submitted to the NRC in PG&E Letter DCL-89-132, dated May 15, 1989). Each of these safety analyses was re-evaluated for the increased response time.

For the RCCA Bank Withdrawal at Power, the safety analyses DNBR limit is met. For the Loss of External Electrical Load and/or Turbine Trip, for the various power levels analyzed, the DNBR did not decrease below the safety analysis limit value. However, by delaying the OTDT trip, the Beginning of Life (BOL) case with automatic pressure control now results in a reactor trip from High Pressurizer Pressure instead of OTDT. Peak pressure is acceptable for this case. For Steam Line Break Core Response at Power, a specific analysis for a range of break sizes was performed. The results of the intermediate size breaks were affected by the assumed OPDT response time. The limiting case, in terms of DNBR, occurred for a break size of 2.1 square feet and resulted in a reactor trip on OPDT. Break sizes larger than 2.1 square feet resulted in a reactor trip on Low Steam Line Pressure Safety Injection. The DNBR

remained above the safety analysis limit value. For Steam Line Break Mass/Energy Releases Outside Containment, the impact of an increase of one second in the overall response time of the OPDT reactor trip was evaluated. For all cases that trip on OPDT, the reactor trip occurs early in the transient, before the tube bundle is uncovered and superheated steam releases occur. The evaluation in Westinghouse SECL-90-369, Revision 1, concluded that a small delay in the time of reactor trip has an insignificant effect on the calculated mass and energy release data for outside containment EQ evaluation.

The results of the safety evaluation for the RTDBE at DCPP have verified that the impact of the small assumed increase in OTDT and OPDT response times is acceptable. (see Westinghouse SECL-90-369, Revision 1)

b. New Steam Line Break Protection

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

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

The DCPP safety analyses that are affected by the SLB protection logic are Steam Line Break Core Response (FSAR Update 15.4.2.1), Steam Line Break Mass and Energy Releases for Containment Response (documented in the Boron Injection Tank (BIT) elimination study report, WCAP-11938, Volumes 1 and 2, "BIT Elimination Study for Diablo Canyon Units 1 and 2"), Steam Line Break for Outside Containment EQ evaluation (documented in the BIT elimination LAR submitted to the NRC in PG&E Letter DCL-89-132, dated May 15, 1989), and Feedline Break (FSAR Update 15.4.2.2). Each of these has been re-evaluated for impact of the New Steam Line Break Protection implementation.

For the SLB Core Response, analyses for SLB Mass and Energy Releases for Containment Response, and SLB Mass and Energy Release Outside Containment were completed as part of the BIT deletion study with both old and new SLB protection logic cases. These analyses are the currently applicable safety analyses for DCPP and remain valid and are not affected by the change to new SLB protection. The currently applicable analysis for Major Rupture of a Main Feedwater Pipe (FSAR Update 15.4.2.2) was performed assuming the new SLB protection logic even though SI does not significantly affect the results of the feedline break analysis on DCPP, as the analysis credits

the steam line check valves. Therefore, the current analysis remains valid and is not affected by the change to new SLB protection.

The results of the safety evaluation for the new SLB protection logic at DCPP has verified that there is no impact on the current safety analyses.

c. Trip Time Delay

Consistent with the approved analysis methodology of WCAP-11325-P-A, DCPP-specific Loss of Normal Feedwater analyses have been performed to provide the safety analysis limits for 1-of-4 and 2-of-4 logic time delay curves. Cases analyzed were Loss of Normal Feedwater to one steam generator and four steam generators at 0, 10, 20, 30, 40, and 50 percent power with Steam Generator Water Level Low-Low Trip Setpoint of 0 percent span.

The time delays were determined by permitting the results of the analysis to approach the acceptance criteria without permitting the part-power loss of normal feedwater analyses to be more limiting than the currently applicable Full Power Loss of Normal Feedwater analysis (FSAR Update 15.2.8). A maximum acceptable time delay on reactor trip and auxiliary feedwater actuation was calculated for each case. In each case, the auxiliary feedwater heat removal capability is sufficient to remove the decay heat such that the pressurizer does not fill. This ensures that all applicable Condition II safety analysis acceptance criteria are met.

The analyses described establish Safety Analysis Limits for the Steam Generator Water Level Low-Low signal delay times and trip setpoints. A number of other events credit the Steam Generator Water Level Low-Low reactor trip. These events were evaluated to ensure that with the time delays calculated above, the current licensing basis events presented in the FSAR Update remain as the limiting transients.

The transients evaluated were: Full Power Loss of Normal Feedwater (FSAR Update 15.2.8), Loss of Offsite Power to the Station Auxiliaries (Station Blackout) (FSAR Update 15.2.9), Major Rupture of a Main Feedwater Pipe (FSAR Update 15.4.2.2), and Steam Line Break Mass/Energy Releases Outside Containment. For the Full Power Loss of Normal Feedwater, the results were more limiting than those of the part-power analyses performed in support of the TTD implementation. (The TTD is only applicable to power levels below 50 percent; above 50 percent the delay is set to zero.) The Station Blackout analyses demonstrate the adequacy of the RPS, the engineered safeguards systems, and natural circulation to limit the RCS heatup by tripping the reactor and removing long-term decay heat. Since the blackout/loss of power signals would directly trip the reactor and initiate the motor and turbine driven auxiliary feedwater pumps for this event, the TTD does not apply. Therefore, the Loss of Offsite Power to the Station Auxiliaries

was not reanalyzed for TTD implementation. The Major Rupture of a Main Feedwater Pipe leading to an RCS heatup is an ANS Condition IV accident. The FSAR Update transients are analyzed assuming full power initial conditions. This assumption maximizes the heatup. In all the feedwater line rupture cases analyzed, the RPS initiated the reactor trip in time to ensure that the ANS Condition IV acceptance criteria are met. (The worst case combination of feedline break area and power level is the 40 percent power, double-ended rupture with offsite power available.) The SLB Mass/Energy Releases Outside Containment EQ evaluation uses data from 70 and 100 percent power. Analyses of lower power levels was not performed, as for the same protection system assumptions, lower initial power levels yield less limiting mass/energy releases. As implementation of the TTD in the DCPP units introduces no time delays at indicated power levels greater than 50 percent, it is concluded that implementation of the TTD does not invalidate the cases in the design basis documentation.

The DCPP Units have ATWS Mitigation System Actuation Circuitry (AMSAC) which is armed whenever reactor power is above 40 percent. Since the TTD circuitry is armed whenever reactor power is less than 50 percent, any condition which results in steam generator water levels that are below the trip setpoints for these functions will actuate both TTD and AMSAC. Since DCPP is equipped with the P-9 permissive, which blocks reactor trip on turbine trip when below the permissive setpoint (which could be as high as 50 percent), a reactor trip from an AMSAC-initiated turbine trip might not occur in the 40 to 50 percent power range. However, analysis of the TTD in the 40 to 50 percent range did not assume simultaneous AMSAC actuation. The analyses would not be affected by the AMSAC-initiated turbine trip since, at these power levels, there is adequate steam relief capability via the steam generator safety valves, steam generator PORVs, and steam dumps to accommodate the load rejection.

Level channels for only two steam generators are represented in Protection Sets I and II at DCPP, while level channels for four steam generators are represented in Protection Sets III and IV. Therefore, the multiple steam generator affected time delays are programmed into the TTD logic for all Protection Sets. Consequently, the less restrictive (longer) time delays associated with a single affected steam generator are not used at DCPP.

d. The safety function of the Steam Generator High-High Level Trip is to protect the core from the consequences of a loss of feedwater control accident. The trip function also provides the non-safety function of turbine protection against excessive moisture carryover. The proposed increase in high-high level trip setpoint from 67 to 75 percent has been evaluated for both the safety and non-safety protection functions and it has been demonstrated that both protective functions will be preserved with the increased setpoint. In addition, safety is enhanced by increasing the margin between the normal level and the

setpoint so that the likelihood of spurious trips due to operational transients is reduced.

e. Unaffected Non-LOCA Accidents

Specific non-LOCA accidents that are unaffected by the system upgrades described in Section C include:

- Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition - FSAR Update 15.2.1
- Rod Cluster Control Assembly Misoperation - FSAR Update 15.2.3
- Uncontrolled Boron Dilution - FSAR Update 15.2.4
- Partial Loss of Forced Reactor Coolant Flow - FSAR Update 15.2.5
- Startup of an Inactive Reactor Coolant Loop - FSAR Update 15.2.6
- Excessive Heat Removal Due to Feedwater System Malfunctions - FSAR Update 15.2.10
- Sudden Feedwater Temperature Reduction - FSAR Update 15.2.10A
- Excessive Load Increase Incident - FSAR Update 15.2.11
- Accidental Depressurization of the Reactor Coolant System - FSAR Update 15.2.12
- Spurious Operation of the Safety Injection System at Power - FSAR Update 15.2.14
- Complete Loss of Forced Reactor Coolant Flow - FSAR Update 15.3.4
- Single Reactor Coolant Pump Locked Rotor - FSAR Update 15.4.4
- Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection) - FSAR Update 15.4.6

f. Conclusions for Non-LOCA Safety Analyses and Evaluations

It has been demonstrated above that the functional upgrades associated with the Eagle 21 process protection system upgrades, including RTDBE, new SLB protection, TTD, and steam generator water level high-high turbine trip setpoint are acceptable with respect to the non-LOCA safety analyses. The analysis results meet all applicable safety criteria.

7. LOCA and Steam Generator Tube Rupture Safety Analyses and Evaluations

The DCPP LOCA and Steam Generator Tube Rupture (SGTR) Safety Analyses previously performed and reported in the FSAR Update have been evaluated to assess the effect of the hardware and software modifications described in Section C of this LAR. The only modification with potential impact on the LOCA and SGTR analyses is the RTDBE modification. This evaluation included large break LOCA, small break LOCA, post-LOCA long-term core cooling subcriticality, hot leg switchover to prevent boron precipitation, and post-LOCA long-term core cooling minimum flow requirement. The potential effect of the revised parameters on the FSAR Update analysis results for each of the above LOCA-related accidents was evaluated and in each case it was shown that these modifications did not result in any design or regulatory limit being exceeded. The LOCA evaluation is documented in Westinghouse SECL-90-369, Revision 1.

F. NO SIGNIFICANT HAZARDS EVALUATION

PG&E has evaluated the no significant hazards considerations involved with the proposed amendment, focusing on the three standards set forth in 10 CFR 50.92(c) as quoted below:

> The commission may make a final determination, pursuant to the procedures in paragraph 50.91, that a proposed amendment to an operating license for a facility licensed under paragraph 50.21(b) or paragraph 50.22 or a testing facility involves no significant hazards considerations, if operation of the facility in accordance with the proposed amendment would not:
>
> 1. Involve a significant increase in the probability or consequences of an accident previously evaluated; or
>
> 2. Create the possibility of a new or different kind of accident from any accident previously evaluated; or
>
> 3. Involve a significant reduction in a margin of safety.

The following evaluation is provided for the no significant hazards consideration standards:

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

   The proposed changes to TS 2.2.1, 3/4.3.1, and 3/4.3.2 reflect upgrades and enhancements to the RPS to be made during the sixth refueling outage for each unit. The significant upgrade to the RPS consists of replacing the Westinghouse 7100 analog process protection equipment with the Eagle 21 digital system. The new system meets all applicable codes and standards for protection grade systems used in nuclear power plants. The use of the digital system avoids most of the drift problems associated with the analog process instrumentation. The Eagle 21 system also has improved test features that include automatic surveillance testing,

self-calibration of analog circuits, and self-diagnosis of system troubles. The general revision of RPS setpoint allowable values is primarily the result of differences in rack drift and measurement and test equipment errors between the analog and digital systems. The new allowable values are calculated in Revision 1 of WCAP-11082, "Westinghouse Setpoint Methodology for Protection Systems," using accepted setpoint methodologies.

The RPS enhancements to be incorporated with the Eagle 21 upgrade are the Steam Generator Level TTD trip reduction feature, elimination of the RCS RTD bypass manifold, and incorporation of the new SLB protection logic. These enhancements are represented as specific revisions to RPS functional units in the proposed change package and are supported by reanalysis of the accidents in the corresponding FSAR Update sections.

Removal of the bypass manifolds and their replacement with RTDs mounted in thermowells installed into the reactor coolant loop piping is the only impact on the RCS boundary. All pressure boundary components will be procured and/or fabricated and installed in accordance with applicable ASME codes and standards. The remaining change is the change to process channel testing in bypass described and evaluated in WCAP-10271 and its supplements.

None of the above changes will increase the probability of an accident previously evaluated.

The proposed changes that incorporate new RPS setpoints, response times, or protection logic have been evaluated by the reanalysis of the corresponding FSAR Update Chapter 15 events. These reanalyses demonstrate that the overall conclusions drawn concerning the plant's ability to cope with design basis events remain unchanged. Therefore, these changes do not increase the consequences of any previously evaluated accident. The proposed changes reflecting new allowable values do not impose any new safety analysis limits or alter the plant's ability to detect and mitigate events. As such, these changes will not increase the consequences of a previously analyzed event. Because the ability of the RPS to detect faults and initiate protective action is not reduced, the FSAR Update analyses remain bounding and the consequences of accidents previously analyzed are not increased.

The change to increase the Steam Generator Water Level High-High Turbine Trip setpoint is based on a reanalysis of the safety analysis limit for turbine trip and feedwater isolation. This analysis demonstrates that the RPS effectiveness in mitigating any design basis event that assumes turbine trip or feedwater isolation from the Steam Generator High-High Water Level Trip is unchanged.

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

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

The RPS monitors selected plant parameters and initiates protective action as required. The proposed changes to the RPS TS reflect new setpoint allowable values, enhanced protection feature setpoints and logic to reduce unnecessary trips, and enhanced RPS testing. The proposed changes that incorporate new RPS setpoints, response times, or protection logic have been evaluated by the reanalysis of the corresponding FSAR Update Chapter 15 events. These reanalyses demonstrate that overall conclusions drawn concerning the ability of the plant to cope with design basis events remain unchanged. The proposed changes do not include any change to previously approved plant parameters, control schemes, or power level. The procurement and installation of the thermowell mounted RTDs is in accordance with all ASME code requirements; however, should any newly installed component fail, the resulting accident is within the envelope of existing accident analyses and does not represent a new or different kind of accident from any previously evaluated.

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

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

The RPS is fundamental to plant safety. The reactor trip system acts to limit the consequences of Condition II events (faults of moderate frequency) by, at most, a shutdown of the reactor and turbine. This imposes a limiting boundary region to plant operation that ensures that the reactor safety limits analyzed in FSAR Update Chapter 15 are not exceeded during Condition II events and that these events can be accommodated without developing into more severe events.

Similarly, the RPS acts to limit the consequences of Condition III events (infrequent faults) and mitigate Condition IV events (limiting faults). This is accomplished by sensing selected plant parameters and determining whether or not predetermined safety limits are being exceeded. If they are exceeded, the system sends actuation signals to those components whose aggregate function best serves to mitigate the severity of the accident.

As previously discussed, the proposed TS changes reflect RPS upgrades and enhancements that are supported by FSAR Update reanalyses, accepted setpoint methodology, and reliability studies reviewed by the NRC Staff. The supporting information demonstrates that the reliability and availability of the RPS are maintained, if not improved, and that the RPS will effectively perform its function of sensing plant parameters to initiate protective actions to limit/mitigate faults.

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

G. NO SIGNIFICANT HAZARDS DETERMINATION

Based on the above evaluation, PG&E concludes that the activities associated with this LAR satisfy the no significant hazards consideration standards of 10 CFR 50.92(c) and, accordingly, a no significant hazards consideration finding is justified.

H. ENVIRONMENTAL EVALUATION

PG&E has evaluated the proposed changes and determined that the changes do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed changes meet the eligibility criterion for categorical exclusion set forth in 10 CFR 52.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), an environmental assessment of the proposed changes is not required.