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PG&E Letter DCL-04-089

U.S. Nuclear Regulatory Commission
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Docket No. 50-275, OL-DPR-80
Docket No. 50-323, OL-DPR-82
Diablo Canyon Units 1 and 2
Response to June 14 and July 6, 2004, NRC Request for Additional Information Regarding License Amendment Request 03-18, "Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair"

Dear Commissioners and Staff:

PG&E Letter DCL-03-183, dated January 7, 2004, submitted License Amendment Request (LAR) 03-18, "Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair." LAR 03-18 proposes to revise the DCPP Technical Specifications (TS) to allow application of 4-volt alternate repair criteria at intersections of SG tube hot-legs with the four lowest SG tube support plates.

On June 14 and July 6, 2004, the NRC staff requested additional information required to complete the review of LAR 03-18. PG&E's responses to the staff's questions are provided in Enclosure 1.

The TS changes originally proposed in PG&E Letter DCL-03-183 need to be supplemented to address the staff's questions. New TS 3.7.19 is proposed which requires a main steam line leakage detection instrumentation system, and new TS 3.7.20 is proposed which provides a main steam line leakage limit. The main steam line leakage detection instrumentation system and main steam line leakage limit are required to support application of leak-before-break methodology to the main steam line piping inside containment. Approval to apply leak-before-break methodology to the main steam line piping inside containment was requested in PG&E Letter DCL-03-183. Enclosure 2 provides marked-up TS pages and Enclosure 3 provides retyped TS pages. Enclosure 4 provides marked-up TS Bases pages for information only.

A001

This information does not affect the results of the technical evaluation or the no significant hazards consideration determination previously transmitted in PG&E Letter DCL-03-183.

A typographical error has been identified in Table 4-12 on page 4-18 of Structural Integrity Associates, Inc., Report No. SIR-03-146, Revision 1, "Leak-Before-Break Evaluation Main Steam Piping Inside Containment Diablo Canyon Power Plant Units 1 and 2," dated December 2003, which was contained in Enclosure 7 of PG&E Letter DCL-03-183. Some rows of the data were inadvertently one row off from their proper location. The error is typographical only and there is no change in the results of the analyses. A revised page 4-18 of Report No. SIR-03-146, Revision 1, is contained in Enclosure 5.

If you have any questions, or require additional information, please contact Stan Ketelsen at (805) 545-4720.

Sincerely,

David H. Oatley
Vice President and General Manager – Diablo Canyon

kjse/4328
Enclosures
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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of PACIFIC GAS AND ELECTRIC COMPANY	))))	Docket No. 50-275 Facility Operating License No. DPR-80
Diablo Canyon Power Plant Units 1 and 2	)))	Docket No. 50-323 Facility Operating License No. DPR-82

AFFIDAVIT

David H. Oatley, of lawful age, first being duly sworn upon oath says that he is Vice President and General Manager – Diablo Canyon of Pacific Gas and Electric Company; that he has executed this response to the NRC request for additional information on License Amendment Request 03-18 on behalf of said company with full power and authority to do so; that he is familiar with the content thereof; and that the facts stated therein are true and correct to the best of his knowledge, information, and belief.

David H. Oatley
Vice President and General Manager – Diablo Canyon

Subscribed and sworn to before me this 30th day of July 2004.

Karen T. Mason
Notary Public
County of San Luis Obispo
State of California

KAREN T. MASON
Commission # 1428454
Notary Public - California
San Luis Obispo County
My Comm. Expires Jul 31, 2007

ENCLOSURE 1

PG&E Response to the June 14 and July 6, 2004, NRC Requests for Additional Information Regarding License Amendment Request 03-18, "Revision to Technical Specifications 5.5.9, 'Steam Generator (SG) Tube Surveillance Program,' and 5.6.10, 'Steam Generator (SG) Tube Inspection Report,' for 4-volt Alternate Repair Criteria for Steam Generator Tube Repair"

NRC Question 1:

By letter dated January 7, 2004, Pacific Gas and Electric Company submitted for staff review and approval a proposed change to the Technical Specifications for the Diablo Canyon Power Plant (DCPP), Units 1 and 2. The requested change is to allow application of 4-volt alternate repair criteria at intersections of steam generator tube hot-legs with the four lowest tube support plates. As a part of the license amendment request, the licensee requested staff approval of using leak-before-break (LBB) methodology to the main steam lines inside of the containment. To complete the review, the staff requests for additional information on the topic of LBB in the submittal.

Question on the Cover Letter dated January 7, 2004

Page 2. The licensee stated that the LBB application to the main steam lines will only be applied until the DCPP steam generators are replaced. (a) Discuss whether this implies that the LBB application will not be applicable to the main steam lines after the replacement steam generators are installed and that the design of the replacement steam generators will consider the full non-LBB dynamic effect of a postulated main steam line break. (b) The licensee stated that LBB is requested only for the segment of the main steam lines inside the containment. If a main steam line break occurs outside the containment, discuss how would the blowdown load be considered in the design of the steam generator tube support plates for the 4-volt alternate repair criteria, assuming that the main steam isolation valve is not closed. (c) Identify when will the steam generators be replaced.

PG&E Response to Question 1a:

Application of LBB will not be applicable to the main steam lines after the replacement SGs are installed. As stated in page 1 of letter DCL-03-183 dated January 7, 2004, the proposed application of LBB to the main steam lines will only be applied until the DCPP steam generators (SGs) are replaced. The current specification for the design of the replacement SGs considers the full dynamic effect of a postulated main steam line break and does not assume that LBB will be applied to reduce the dynamic effect of a steam line break.

PG&E Response to Question 1b:

The steam line flow restrictor is located downstream of the SG outlet nozzle inside containment. The flow restrictor is located near the SG outlet nozzle in order to reduce the probability of occurrence of a large main steam line break between the SG nozzle and the flow restrictor. LBB was requested to be applied to the main steam lines inside containment in order to exclude large main steam line breaks upstream of the flow restrictor from consideration for determining the loads on the SG tube support plates (TSPs) following a main steam line break. The analysis to determine the thermal hydraulic loads on the SG TSPs assumed the steam line break occurred just downstream of the flow restrictor (referred to as a small main steam line break), based on application of LBB to preclude larger breaks in the steam line upstream of the flow restrictor. Since any steam line break outside containment is downstream of the steam line flow restrictor, the SG TSP loads due to a steam line break outside containment would be less than or equal to the SG TSP loads considered for the TSP displacement analysis supporting the 4-volt alternate repair criteria.

PG&E Response to Question 1c:

The replacement of the DCPP Unit 1 and 2 SGs requires funding approval by the California Public Utilities Commission (CPUC). PG&E has filed a ratemaking application with the CPUC to recover the costs of replacing the DCPP Unit 1 and 2 SGs. PG&E's ratemaking application provides technical and cost justification and a strong recommendation to perform a Unit 2 SG replacement in refueling outage 14 (2R14) starting in February 2008, and a Unit 1 SG replacement in refueling outage 15 (1R15) starting in January 2009. PG&E has requested CPUC approval of the ratemaking application by the end of 2004.

NRC Question 2:

Questions on Enclosure 1 to the January 7, 2004, Letter

Page 14. The LBB analysis showed that DCPP needs to detect a leak rate of 0.2 gallons per minute (gpm) from a postulated main steam line flaw. The licensee stated that DCPP's leakage detection system is capable of detecting a leak rate of 0.2 gpm; however, the staff has following concerns regarding such capability:

The licensee stated that it has a containment condensation measuring system which measures moisture condensed from the containment atmosphere via the cooling coils of the fan cooler air circulation units. However, a good estimate of condensate can be measured when equilibrium is been reached, which implies that there will be a delay in detection. In addition, this system has a wide range of detection capability (0.1 gpm to 30 gpm) which leads to a question of accuracy and reliability because the lower end of the detection capability, 0.1 gpm, is close to the required detection of 0.2 gpm.

The licensee stated that various air temperature and pressure sensors are used to supplement indications of leakage into containment. It seems that these sensors detect occurrence of leakage rather than quantity of leakage which is required for the LBB application.

The licensee described the two containment sumps' capability; however, it seems that a leakage will not be noticed until an hour from leakage. The licensee stated that a change of 5 gallons in the sump is equivalent to a 0.3 inch level change in the sump which is discernible with the level indicator; however the licensee did not provide much supporting data. Also, if there is an indication of water level increase in the sump, the staff is not clear how would the operator know whether the source is from the main steam lines. There is an inherent time delay for the leaking steam to condense to liquid so as to be measured by the sump.

The licensee referenced staff's approval of LBB for certain Class 1 piping at Kewaunee. Kewaunee has four leakage detection systems which provide redundancy and diversity. Two of which detect radiological emissions which provides faster response than the containment sump. The Kewaunee LBB pipes are a part of reactor coolant system whose leakage would be detected readily due to radiological emission. The main steam lines contain no radioactive coolant. The staff is not certain whether DCPP's detection system has redundancy and diversity.

The licensee discussed an upcoming design change to allow the plant process computer to monitor the structure sump levels continuously and to provide appropriate indication to the operators in the event of a 0.2 gpm leakage. However, the staff is not clear whether the design change would be completed before the LBB application becomes effective.

Considering above concerns, the licensee needs to provide rigorous assessment and data to demonstrate that its leakage detection system can detect a leak rate of 0.2 gpm in main steam lines. As a minimum, the licensee needs to provide the following:

(a). Demonstrate that the leakage detection system meets USNRC Regulatory Guide 1.45 and address the reliability, diversity, redundancy, and sensitivity of the leakage detection system.

(b). When a leak occurs in the containment, discuss how would the detection system identify the leak is from the main steam lines and how fast would the operator obtain such information.

(c). Clarify whether the design change on the plant process computer aforementioned has been completed. If the design change is a part of the technical basis for the LBB application, then the design change should be completed prior to the staff approval of LBB application. Discuss whether this design change would result in a new requirement to Technical Specification section 3.4.15 (Limiting

Condition for Operation 3.4.15). Discuss corrective actions if testing of the design change shows that the monitoring system does not function properly.

(d). Discuss the length of time for the condensation measuring system and containment sump to measure/detect 0.2 gpm of steam leakage

(e). It seems that only containment sump and condensation measuring system are the only two credible leakage detection systems. In light of defense-in-depth and redundancy, if one system is inoperable (e.g. containment sump fails), discuss how many detection system(s) need to be operable to be able to detect a leak rate of 0.2 gpm. An example of required operable detection systems with associated action statements should one detection system inoperable may be found in DCPP technical specification 3.4.15.

(f). Discuss in detail the capability of the air temperature and pressure sensors in detecting a leak rate of 0.2 gpm.

PG&E Response to Question 2a:

For DCPP, the primary main steam line leakage detection instrumentation system consists of two containment (structure) sump level monitor systems that are the normal means of detecting a main steam line break and are considered fully redundant and capable of detecting a 0.2-gpm steam leak inside containment. The two containment sump level monitor systems are redundant to each other. Each containment sump level monitor system consists of a containment sump, an operating containment fan cooler unit (CFCU) with the condensate drain aligned to the sump, a sump level indicator, and a sump level monitor computer that will provide a control room alarm. The operation of the containment sump level monitor system is based on the collection of water condensed from the containment atmosphere. The containment atmosphere is circulated through the CFCUs to remove heat and moisture from the containment. Cooling coils cool air passing through the CFCUs. Water vapor contained in the air will condense onto the cooling coils. This condensation, in turn, will accumulate in the CFCU drains and drain to the containment sumps where the levels will be continuously monitored for accumulation and accumulation rate by the plant process computer (PPC) or equivalent computer device.

As a substitute for one of the two sump level monitor systems, the CFCU condensate collection monitor system provides a separate detection method that is also capable of detecting a 0.2-gpm steam leak. The condensation from the CFCUs is directed to the containment structure sumps via a drain line. Individual drain lines may be closed via remote manual valves to determine the condensation rate from the associated CFCU (the time between the actuation of two level switches on a standpipe corresponds to the condensation rate). Only one CFCU condensate collection monitor can be placed in service at a time. During normal operation these valves are left open because the frequent alarms would constitute an operator distraction.

Only one of these three systems is necessary to detect a 0.2-gpm steam leak inside containment. A new proposed TS 3.7.19 provides TS requirements for the two containment sump level monitor systems. See the response to question 2e for a more detailed description of TS 3.7.19.

The main steam line leakage detection instrumentation meets the intent of the primary guidelines of Regulatory Guide (RG) 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," dated May 1973, in that it is redundant, diverse, reliable, sensitive, and controlled by the TS. The main steam line leakage detection instrumentation for the main steam line piping inside containment does not meet RG 1.45 because RG 1.45 was created for reactor coolant system piping leakage detection systems and provides guidelines for use of an airborne particulate radioactivity based monitor for leakage detection. Although DCPP has an airborne particulate radioactivity monitor, since radioactivity levels are very low or nonexistent in the secondary system, radioactivity based monitors cannot be relied upon to detect leakage in main steam line piping.

The DCPP main steam line leak detection instrumentation systems are similar in design to that used for the Combustion Engineering System 80+ and Westinghouse AP600 advanced reactor designs. The Combustion Engineering System 80+ design uses containment sump level and containment cooler condensate flow to detect main steam line leakage and was approved by the NRC in NUREG-1462, Volume 1, "Final Safety Evaluation Report Related to the Certification of the System 80+ Design, Docket No. 52-002," dated August 1994. The Westinghouse AP600 design uses a single containment sump with two level indicators and sump total flow sensors to detect main steam line leakage and was approved by the NRC in NUREG-1512, "Final Safety Evaluation Report Related to the Certification of the AP600 Standard Design, Docket No. 52-003," dated August 1998. The main steam line leak detection instrumentation systems approved by the NRC for use in the Combustion Engineering System 80+ and Westinghouse AP600 advanced reactor designs do not meet all the guidelines of RG 1.45.

Reliability

The availability of each of the containment sump level indicators during plant Modes 1 through 4 since January 2000 was reviewed. Each of the indicators was unavailable approximately 10 hours since January 2000. The worst performance was 99.97 percent available, or 12.6 hours unavailable. Thus, the containment sump level indicators are considered highly reliable and reliable enough to be credited by proposed Technical Specification 3.7.19.

The PPC was similarly reviewed for availability since January 2000. DCPP Unit 1 has had an availability of 99.24 percent (271 hours unavailable) and DCPP Unit 2 has had an availability of 99.77 percent (88 hours unavailable). Although the unavailable time appears large, it is comprised of events typically less than an hour in duration. The longest event was 14 hours and only one other event was over 10 hours. During such times of computer unavailability, the proposed TS 3.7.19 will require a CFCU condensation collection system to be placed in service by plant operators and a containment sump inventory calculation to be performed every four hours to assure timely detection and to provide redundant monitoring of sump inflow.

Diversity

The main steam line leakage detection instrumentation system contains two containment sump level monitor systems that are the primary means of detecting a steam leak inside containment. The CFCU condensate collection monitor provides a diverse and redundant means of measuring the leakage of steam into the containment atmosphere if one or both of the containment sump systems are unavailable.

In addition to the level indication system described above, each containment sump has three level switches. On increasing level, the first switch automatically starts the sump pump, lighting a pump run indication light at the normally manned auxiliary control board. The second and third are set at the same level and start the backup sump pump and initiate a control room alarm respectively. A flow totalizer at the auxiliary control board indicates total pumped volume. The flow totalizer makes an audible clicking noise, at the auxiliary control board, while the sump is being pumped down. Thus, the level switch system also provides a diverse method of identifying leakage inside containment.

Recording of the containment sump levels and sump pumped flow for the containment sumps and reactor cavity sumps by the operators is required on a surveillance interval of once per 12 hours in plant Mode 1 through 4. The net total leakage into the sumps since the previous surveillance is calculated, the identified RCS leakage is subtracted, and diagnostic action is initiated if the leakage change is above the specified limit. This limit is currently specified as 0.75 gpm as a result of the existing TS 3.4.13.b limit of 1.0 gpm unidentified leakage. This leakage limit will be reduced to below 0.2 gpm to support the application of LBB to the main steam lines. Additionally, the auxiliary building senior operator checks the sump level and totalizer indications every two hours. Thus, the operators provide a reliable, redundant, and diverse check for low leak rates and are capable of detecting developing conditions inside containment within an operating shift.

A summary of the containment main steam line detection systems is provided in Table 1.

Redundancy

The two containment sump level monitoring systems are redundant to each other in that a 0.2-gpm steam line leak would be detected and alarmed in each. Each containment sump level monitor system consists of a containment sump, an operating CFCU aligned to the sump, a sump level indicator, and a sump level monitor computer. The computer provides sump monitoring, control room alarming, and data quality monitor. If one or both of the containment sump level monitoring systems are not operable, new TS 3.7.19 will require a CFCU condensate collection monitor to be placed in service. Each CFCU has an associated condensate collection monitor, any one of which can be placed in service to detect leakage inside containment.

Sensitivity

Position C.2 of RG 1.45 states that leakage to the primary reactor containment from unidentified sources should be collected and the flow rate monitored with an accuracy of 1 gpm or better. Position C.5 of RG 1.45 states that the sensitivity and response time of each leakage detection system employed for unidentified leakage should be adequate to detect a leakage rate, or its equivalent, of one gpm in less than one hour. The containment sump level monitor instrumentation sensitivity and response time meet the guidelines contained in RG 1.45 position C.2 and C.5 in that the containment sump level monitor instrumentation can detect a steam leak of 1.0 gpm within one hour. Accounting for the possible fan cooler alignments, the containment sump level monitor instrumentation is also capable of detecting a 0.2-gpm steam leak inside containment (see response to Question 2d for additional discussion). With the instrumentation currently installed, the minimum level change that can be reliably discerned is approximately 0.3 inches. This change corresponds to an inventory change of 4.41 gallons. This sensitivity was determined by digitally recording actual sump level monitor indication transmitter output over an eight-hour period and determining the best sensitivity achievable without creating nuisance alarms for operators.

TS Requirements for the Main Steam Line Leakage

New TS are provided to include limiting conditions for operation for the main steam leakage detection instrumentation and main steam line leakage. The new proposed TS 3.7.19, "Main Steam Line (MSL) Leakage Detection Instrumentation," provides TS requirements for the two containment sump level monitor systems during Modes 1 through 4. Actions are provided for one containment sump level monitor system inoperable, two containment sump level monitor systems inoperable with level indicators operable, and two containment sump level monitor systems inoperable with level indicator(s) inoperable. The new proposed TS 3.7.20, "Main Steam Line (MSL) Leakage," provides a TS requirement that limits the maximum main steam line leakage through the pipe walls inside containment. Proposed new

TSs 3.7.19 and 3.7.20 are contained in Enclosures 2 and 3 and the associated TS Bases are contained in Enclosure 4.

PG&E Response to Question 2b:

For the containment sump level monitor system, monitoring by the PPC or equivalent computer device of the change in level will be provided on a continuous basis. Once the alarm setpoint is reached, a control room annunciator alarm will be generated, alerting the operator that the water accumulation rate in the containment sumps has exceeded 0.2 gpm. With two CFCUs operating, a 0.2-gpm leakrate is expected to result in an identifiable change in sump level and associated alarm in approximately one hour (see response to Question 2d for additional details). Larger steam leaks will be detected more quickly.

To respond to the alarm, operators will follow annunciator response procedural guidance. The annunciator response procedural guidance provides guidance on how to identify the leakage source. The time to determine if the leak is due to a steam line leak depends on many factors including the size of the steam line leak, the location of the steam line leak, and the amount of leakage from other systems that may exist.

The source of leakage inside containment can be identified through use of diverse indications. The pressure, temperature, and radiation monitors would confirm the existence of a leak in the Reactor Coolant System (RCS)/charging/letdown systems. The absence of the radiation monitor signal would indicate to the operators that there is a possible leak on the feedwater/steam, component cooling water (CCW), or firewater systems. Leakage in the CCW system can be verified by monitoring the change in the CCW head tank level.

Table 1
Containment Main Steam Line Leak Detection Systems

Detection Process	Medium	Type	Sensitivity	Approximate Time to Detect 1.0 gpm Steam Leak	Seismic Category[f]	Control Room Alarm or Indication	Availability	Redundancy
Containment Sump Level Change Rate Monitoring	Liquid	Change in time required to accumulate specified volume	Approximately 0.3 inch minimum change	<1 hour	II	Both	>99%	Yes (two sumps with dedicated level indicators)
Containment Condensation (CFCU)[a]	Liquid	Change in time required to accumulate fixed volume[b]	See note b.	<1 hour[d,e]	II	Alarm	>99%	Yes (CFCUs can be individually selected)
Shiftly Operator Surveillance of sump inventory	Liquid	Volume change per time	±1 inch level (15 gallons) in each sump	12 hours	N/A	Yes[c]	100%	No
Level Switches	Liquid	Liquid level and pressure differential	±1 inch level	12 hours	II	Alarm on high-high Level / Backup Pump Start	>99%	Yes (two sumps)
Pressure / Temperature	Air	Containment Ambient Monitoring	N/A - Confirmatory trend only for small leaks	N/A - Confirmatory trend only for small leaks	I / I & II	Both	>99%	Yes

[a] Containment condensation measures moisture condensed by the fan cooler condensate collection system.
[b] Level Switches (Hi and Hi-Hi) are provided in each CFCU drain line. The level switches have a fixed location in each drain line providing a repeatable alarm. The time intervals between the receipt of the Hi and Hi-Hi alarms are monitored and logged by the operator. Alarm intervals less than a conservative pre-defined value directs the operator to perform an RCS water inventory balance and other diagnostic steps to identify the source of the leakage into containment.
[c] Requires operator communication to control room on determination of over-limit condition.
[d] Requires operator action (i.e. close valve, start-stop pump, etc. and operator monitoring and logging).
[e] Requires operator monitoring and logging to note changes in rate, level, flow, etc.
[f] Seismic Category I systems are designed to perform required safety functions following a Double Design Earthquake. Category II instrument systems were designed to function under conditions up to a Design Earthquake.

PG&E Response to Question 2c:

The design change to allow the PPC to monitor the containment sump levels continuously and to provide appropriate indication to the operators in the event of a 0.2-gpm leak has not been completed at this time and is currently scheduled to be installed in September of 2004. The design change is required to provide a control room alarm in the event of a 0.2-gpm leak using the containment sump level monitor system. Successful completion of the design change will occur prior to crediting the requested 4-volt alternate repair criteria. If testing shows the containment sump monitoring system does not meet the sensitivity requirements (0.2 gpm), then the design will be modified such that it meets design criteria, or a different leak detection monitoring system will be utilized. If a different leak detection monitoring system needs to be utilized, NRC approval may be required if TS changes are required or if the design changes are determined to require prior NRC review and approval by a 10 CFR 50.59 evaluation.

Crediting LBB for the main steam lines will result in new TS requirements for main steam line leakage detection instrumentation. These requirements will not be incorporated into the current TS 3.4.15 because TS 3.4.15 applies to reactor coolant system leakage instrumentation. Since the main steam line leakage detection instrumentation will only be required to support the LBB analysis for the 4-volt alternate repair criteria for the current SGs, a new TS 3.7.19 is proposed to provide requirements for the main steam line leakage detection instrumentation. The proposed new TS 3.7.19 is contained in Enclosures 2 and 3, and the associated TS Bases is contained in Enclosure 4. TS 3.7.19 relies on the redundant containment sump level monitor system required by the current TS 3.4.15.a as the primary main steam line leakage detection instrumentation. The diverse steam line leakage detection is provided by the CFCU condensate collection monitor.

PG&E Response to Question 2d:

Containment sump level monitor indications will provide the most rapid and direct means of identifying a small steam leak inside containment. The containment sumps collect leakage from many sources within containment, most notably the CFCU condenser coils.

The level of each sump will be continuously indicated in the control room and will alarm if it reaches the high-high level. Additionally, the rate of level change of each sump will be continuously monitored for a change in the rate of increase. The timeliest response is assured by monitoring the change in each sump level independently. This reduces the potential for the response to be biased by the steam line crack location with respect to the CFCUs that are operating. The monitoring system will initiate a control room alarm if either sump level changes by a specified amount. This amount will be set to assure the ability to detect a 1.0-gpm leak within one hour, and to detect a 0.2-gpm leak. It is expected that the system will be capable of detecting a 0.2-gpm leak in approximately one hour. Detection of slower developing leaks is accomplished in a similar manner by monitoring level trends over longer periods.

The expected time required to provide positive indication of leakage is estimated based on the following assumptions and typical parameters:

- Volume of containment is 2.55 x 10^6 cubic feet
- Containment ambient temperature is 91°F
- Containment pressure is at 0 pounds per square inch gage
- Relative humidity inside containment is approximately 43 percent
- Air temperature at the exit of the CFCU is 66°F
- Airflow is approximately 110,000 standard cubic feet per minute (scfm) per CFCU
- There are two or more CFCUs in operation in high speed
- The holdup time inside containment is negligible due to the high air turnover rate
- The relative humidity at the fan cooler discharge is 100 percent at the discharge conditions

Two CFCUs process 100 percent of the containment atmosphere approximately every 12 minutes (about 8 minutes for normal operation with three CFCUs). With this rapid turnover, the containment atmosphere is maintained at a humidity ratio equal to the dew point of the CCW temperature. Any moisture added to the containment environment via steam leakage is continuously removed to the sumps via the CFCU condensation system. This operation is evidenced when the CFCU condensate collection system is placed in service; typically, the measurement standpipe fills several times per 12-hour operating shift.

A steam leak inside containment will add moisture and energy to the containment atmosphere. The bulk containment humidity ratio (pound moisture to pound dry air) will rise until the CFCU condensation removal rate equals the steam leak rate. Containment temperature and pressure would rise a very small amount for small steam leaks, less than a degree change in bulk containment temperature and an insignificant change in pressure. Although available instrumentation is not of sufficient accuracy to reliably detect leakage based on such small changes, operators will check these parameters in the event of a sump alarm to confirm the existence of a leak.

In the base case, two CFCUs are assumed to be operating. This corresponds to a net airflow of approximately 220,000 scfm and a containment atmosphere turnover time of approximately 12 minutes. Under these conditions, the increase in water vapor due to a 0.2-gpm leakrate was determined to result in an identifiable change in sump level (0.3 inches) in approximately one hour. Larger steam leaks will be detected more quickly.

When more than two CFCUs are in operation, the response time is expected to be reduced slightly due to the higher recirculation rate inside containment (330,000 scfm vs 220,000 scfm). Similarly, when CFCUs are in operation in low speed, the response time is expected to be increased slightly due to the lower recirculation rate inside containment. Normal plant operation is with three CFCUs in operation in high speed.

If one or both containment sumps are unavailable, a CFCU condensate collection monitor will be used. A 0.2-gpm leak would take about 30 minutes to reach a new containment equilibrium humidity and another 30 minutes to fill the volume between the level switches on the condensate drain line. Thus, it is expected that the CFCU condensation collection monitor is also capable of detecting a 0.2-gpm steam leak in approximately one hour. This system is placed in service whenever the containment atmosphere gaseous radioactivity monitor is unavailable per current TS 3.4.15.c.

PG&E Response to Question 2e:

The two containment sump level monitor systems are considered redundant and capable of detecting a 0.2-gpm steam leak. As a substitute for one of the sumps, the CFCU condensate collection monitor utilizes a separate detection method that is also capable of detecting a 0.2-gpm steam leak. Only one of these three systems is necessary to detect a 0.2-gpm steam leak inside containment. Additional actions will be performed to address less than two operable detection systems in service.

New TS 3.7.19 requires two containment sump level monitor systems to be operable. This provides two redundant systems that can detect a steam line leak rate of 0.2 gpm. New TS 3.7.19 is structured to ensure two means of detecting a 0.2-gpm leak will be used at all times. Unit shutdown is required in the event that two means cannot be provided. If one containment sump level monitor system is inoperable, a CFCU condensate collection system must be placed in service within four hours. This provides a diverse system that can detect the existence of main steam line leakage. If two containment sump level monitor systems are inoperable with level indicators operable (e.g., loss of PPC, loss of control room alarm system), a CFCU condensate collection system must be placed in service within four hours and a containment sumps inventory must be performed once per four hours. The CFCU condensate collection system and containment sump inventory will provide a diverse method to detect main steam line leakage. If two containment sump level monitor systems are inoperable with level indicator(s) inoperable (e.g., loss of both level indicators due to loss of power supply), a CFCU condensate collection system must be placed in service within four hours and a visual inspection of the steam lines inside containment must be performed once per 72 hours. The visual inspection of the steam lines inside containment will provide a diverse method to detect main steam line leakage during the time when the containment sump level monitor system is not operable. During this time, the sump level switch system and sump pump operation will still be available and provide additional indications of a leak. Enclosures 2 and 3 provide the proposed TS 3.7.19.

PG&E Response to Question 2f:

Large steam leaks in containment would result in a notable increase in temperature and pressure. However, a 0.2-gpm steam leak would be a very small additional heat load on the CFCUs, and would result in less than a degree change in bulk containment temperature and an insignificant change in pressure. Daily fluctuations in these parameters are greater than the expected change for small steam leaks. Thus, detection of a 0.2-gpm steam leak based on these parameters is not considered reasonable – frequent alarms based on the containment pressure or temperature would result in desensitizing the operators to these parameters. However, the pressure and temperature trends provide a diverse means of confirming the existence of a small steam leak inside containment when an alarm is received.

NRC Question 3:

Page 14. The licensee stated that only limiting welds in the main steam lines will be inspected in terms of stress and leak detection. The licensee also stated that the limiting weld in each main steam line is the pipe-to-flued head weld at the containment penetration. The staff believes that this inspection scope may not be sufficient to assure integrity of the main steam lines in light of the concerns on the leakage detection capability. The licensee needs to (a) explore inspection scope expansion to show that the structural integrity of the main steam lines is adequate monitored. (b) Provide the total number of the welds in the main steam lines, and the total number of the main steam pipe welds that are covered by the LBB application. (c) Discuss the inspection method. (d) Discuss exactly when will the welds be inspected, other than the fact that the ASME Code inspection requirements will be followed. (e) Discuss the accessibility of welds for inspection. (f) Explain why the pipe-to-fluid head weld was selected for inspection based on leak detection, other than by stresses.

PG&E Response to Question 3a:

In view of the staff's concern over leak detection capability, and to provide additional confidence in the structural integrity of the main steam lines, PG&E will increase the scope of the weld inspections to include all of the circumferential welds where the leak rate is calculated to be less than 5 gpm (required leak detection capability less than 0.5 gpm). These are the locations of high normal operating plus dynamic stresses but low normal operating stress, as shown in Figures 5-11 and 5-12 of the report SIR-03-146, Revision 1. There are 15 circumferential welds that fall into this category: 9 that are in the Unit 1 main steam lines and 6 that are in the Unit 2 main steam lines. Additionally, each intersecting seam weld will be examined for a distance of 2.5 times the thickness from the edge of the scheduled circumferential weld. The 15 circumferential welds to be inspected are:

Main Steam Line 1-1: Welds WICG10-1/250, RB-228-1, WICG2-1, RB-228-3/251
Main Steam Line 1-2: Welds WICG10-2/277, RB-227-3/278
Main Steam Line 1-3: Weld WICG10-3/315
Main Steam Line 1-4: Welds WICG10-4/343, RB-225-3/344
Main Steam Line 2-1: Weld WICG9-1/343
Main Steam Line 2-2: Welds RB-227-12/360, RB-227-10
Main Steam Line 2-3: Weld RB-226-12/375
Main Steam Line 2-4: Welds RB-225-8/327, RB-225-12/325

The nine Unit 1 circumferential welds will be inspected according to the schedule contained in the following table:

Main Steam Line for Unit 1	Main Steam Line Weld Inspection Schedule			
	Outage # 1R13	Outage # 1R14	Outage # 1R15	Outage # 1R16
1-1	WICG10-1/250	WICG2-1 **	RB-228-1*	RB-228-3/251*
1-2	WICG10-2/277	-	RB-227-3/278*	-
1-3	WICG10-3/315	-	-	-
1-4	WICG10-4/343	RB-225-3/344	-	-

* This weld will not be inspected if the Steam Generators are replaced prior to or during the outage.
** This will include the adjacent pipe to nozzle weld (WICG1-1).

The six Unit 2 circumferential welds will be inspected according to the schedule contained in the following table:

Main Steam Line for Unit 2	Main Steam Line Weld Inspection Schedule		
	Outage # 2R12	Outage # 2R13	Outage # 2R14
2-1	WICG9-1/343	-	-
2-2	RB-227-12/360	RB-227-10	-
2-3	RB-226-12/375	-	-
2-4	RB-225-12/325	-	RB-225-8/327*

* This weld will not be inspected if the Steam Generators are replaced during the outage.

PG&E Response to Question 3b:

With the exception of DCPP Unit 1, Loop 3, each main steam line in each unit has 12 circumferential welds inside containment, including the pipe-to-nozzle weld at the SG and the pipe-to-flued head weld at the containment penetration. DCPP Unit 1, Loop 3, has only 11 welds. Additionally, the pipe and fittings are mostly seam welded. Although the application of LBB is only used to preclude larger breaks in the steam line upstream of the flow restrictor, all 47 welds in Unit 1, and 48 welds in Unit 2, are covered by the LBB analysis.

PG&E Response to Question 3c:

The main steam line welds inside containment will be inspected by the volumetric ultrasonic method using personnel, equipment, and procedures qualified in accordance with ASME Section XI, Appendix VII, and the Performance Demonstration Initiative (PDI) for conformance with ASME Section XI, Appendix VIII.

<u>PG&E Response to Question 3d:</u>

The penetration pipe-to-flued head welds will be inspected in the next refueling outage for each unit: Unit 1 refueling outage 13 (1R13) and Unit 2 refueling outage 12 (2R12). The SG replacements are currently scheduled in 1R15 and 2R14. The schedule for the inspection of the nine Unit 1 circumferential welds and the six Unit 2 circumferential welds (welds that required leak detection capability is less than 0.5 gpm) is provided in the response to Question 3a. The main steam line weld inspection schedule significantly exceeds the ASME Code requirements that would require four welds per unit to be examined, distributed over ten years.

<u>PG&E Response to Question 3e:</u>

All main steam line welds inside containment are accessible for examination with greater than 90 percent coverage. Insulation removal and scaffolding will be required. The pipe-to-flued head and pipe-to-nozzle welds can be covered from a single side normal to the weld using PDI-qualified personnel and procedures.

<u>PG&E Response to Question 3f:</u>

The pipe-to-flued head location was selected for inspection because it is the limiting location from the standpoint of having high normal operating plus dynamic stresses, but low normal operating stress, as shown in Figures 5-11 and 5-12 of Structural Integrity Associates, Inc., Report No. SIR-03-146, Revision 1, "Leak-Before-Break Evaluation Main Steam Piping Inside Containment Diablo Canyon Power Plant Units 1 and 2," dated December 2003. Consequently the pipe-to-flued head location requires the greatest leak detection capability. Referring to Figure 5-11, for example, for lead 1-1, node point 20, which is the pipe-to-flued head weld, the combination of high normal operating plus dynamic stresses but low normal operating stress results in a calculated leakage for the critical crack size at the lowest leakage rate, 2 gpm. This location will therefore require detection of a leak rate of 0.2 gpm, which is the lowest of any location.

NRC Questions on Structural Integrity Associates, Report No., SIR-03-146, Revision 1.

<u>NRC Question 4:</u>

Page 3-1. It is stated that the probability of water hammer in the main steam lines is low. Discuss the probability of a steam hammer in the main steam lines.

PG&E Response to Question 4:

The statements made on page 3-1 of report SIR-03-146, Revision 1, apply for both water and steam hammer. In addition to the sources cited in the SIR-03-146 report, NUREG/CR-2781 and EPRI report NP-6766 identified that only eight water hammer events were reported on the main steam system for the entire pressurized water reactor fleet. Out of these eight events, six were due to outboard isolation valve closures or openings, one occurred far away near the turbine, and one was in a relief valve discharge line. No water hammer or steam hammer event has occurred in the main steam piping system inside containment at DCPP. In addition, PG&E follows the guidelines recommended in EPRI Topical Report TR-106438, "Water Hammer Handbook for Nuclear Power Plants," Revision 1, to manage and prevent water hammer events at DCPP. Changes in operating procedure and/or system design are made, as necessary, to preclude these events from occurring. The pipe routing and valve selection in the main steam system are designed to reduce the effects of steam and water hammer. Therefore, water or steam hammer damage is unlikely to occur in the main steam piping system at DCPP. Loads due to main steam isolation valve (MSIV) rapid closure have been considered and are sometimes controlling in determining critical flaw sizes.

NRC Question 5:

Page 4-3. Section 4.3. It is stated that the maximum of either the safe shutdown earthquake (SSE) load or (MSIV) actuation load for a location is used. In NUREG-1061, Volume 3, page 5-3, and in draft SRP 3.6.3, it is stated that normal plus SSE loads are used in the critical flaw calculation, no other dynamic loads were discussed. Provide the basis and reference that allow the use of the higher of either SSE load or MSIV load as the dynamic loads.

PG&E Response to Question 5:

PG&E agrees that NUREG-1061, Volume 3, and SRP 3.6.3 do not require that dynamic loads other than SSE be considered when evaluating critical flaw sizes. PG&E has conservatively also considered the MSIV rapid actuation loads at the few locations where they are of higher magnitude than the SSE loads. Including the MSIV loads has resulted in smaller critical flaw sizes at these locations.

NRC Question 6:

Page 4-3. Section 4-3. For the critical flaw calculations, it is stated that the maximum of SSE and MSIV loads is added to the normal operating load. Clarify whether "the maximum of SSE and MSIV loads" means the higher of either the SSE load or the MSIV load.

PG&E Response to Question 6:

"The maximum of the SSE loads and MSIV loads" does mean the higher of either the SSE or the MSIV load.

NRC Question 7:

Pages 4-11 to 4-26. Tables 4-5 to 4-12. (a) Discuss why the dynamic loads in Unit 1 lines are much higher than the dynamic loads in Unit 2 lines. (b) In the footnote of Tables 4-5 to 4-12, the normal operating load is equal to dead weight and thermal expansion, but pressure was not mentioned. Discuss whether pressure is a part of the normal operating load.

PG&E Response to Question 7a:

The MSIV loads in Unit 1 are much higher than in Unit 2 because they were calculated using different methodologies. The Unit 1 loads were based on simplified but very conservative methods and assumptions. The Unit 2 loads were calculated using more sophisticated analytical tools. These loads were determined by force time history analysis of forcing functions developed for each pipe segment using the Bechtel computer code GAFT, which were verified against test data from Arkansas Nuclear One Unit 2. Use of more sophisticated analytical tools and methodologies enabled a reduction in loads while still remaining conservative.

The SSE loads are lower in Unit 2 because the four main steam lines contain an additional vertical pipe support that is not present in Unit 1.

PG&E Response to Question 7b:

Pressure is included in both the normal operating load and the normal operating plus dynamic load. This was stated at the beginning of Section 4.3 of report SIR-03-146, Revision 1.

NRC Question 8:

Page 5-7. Section 5.2.1 Clarify how the leakage was determined using Figures 5-2, 5-3, and 5-6

PG&E Response to Question 8:

In general, the following steps are taken in determining the leakage from Figures 5-2, 5-5, and 5-6 of report SIR-03-146, Revision 1:

- For a particular node, the normal operating procedure (NOP) moment and the normal operating procedure plus dynamic (NOP+DYN) moment are obtained from Tables 4-5 through 4-12.

- The leakage (circumferential) flaw size is determined from the generic relationship between the NOP+DYN moment and leakage flaw length shown in Figure 5-2. As discussed in Section 5.1.1, the leakage flaw length is the minimum of the values determined by two approaches as required by NUREG-1061, Volume 3. In the first approach, it is calculated as half the critical flaw length with a factor of unity on the NOP+DYN moment combination. In the second approach, it is determined as the critical flaw length with a factor of square root of two on the NOP+DYN moments. As shown in Figure 5-2, the first approach is controlling since it produces a smaller leakage flaw length.

- Knowing the leakage (circumferential) flaw size and the NOP moment, the leakage for a particular location can be determined from the generic relationship between leakage and flaw size for the particular NOP moment as shown in Figure 5-5.

The above steps involve calculating the leakage on a node-specific basis for over 300 nodes within the eight main steam lines. For simplicity of presentation in the report, Figures 5-2 and 5-5 were combined to determine combinations of NOP and NOP+DYN moments that produce a particular leakage. Figure 5-6 shows combinations of moments that produce leakages of 2, 3.5, 5, and 10 gpm. The actual NOP and NOP+DYN moments from Tables 4-5 through 4-12 are then plotted on these curves and are shown in Figure 5-11 for DCPP, Unit 1, and Figure 5-12 for DCPP, Unit 2. In these figures, a point above a particular leakage flow line indicates that the calculated leakage at that point exceeds the leak rate of that curve. Figure 5-11 and Figure 5-12 provide a convenient means for graphically plotting all the nodal locations to determine the range of required leakage detection.

<u>NRC Question 9:</u>

Pages 5-14 & 5-15. The critical crack size in the circumferential and axial direction are shown in Figures 5-3 and 5-4, respectively. The staff is not clear about the crack sizes. Identify the exact critical flaw size, crack orientation, and location. Identify the leakage flaw size, crack orientation, and location.

<u>PG&E Response to Question 9:</u>

Explicit critical flaw sizes were not determined for each node point location, as this would have required over 300 calculations. Instead, this was done on a generic basis for circumferential flaw size versus stress and axial flaw size versus stress, using the following methodology. Figure 5-3 and Figure 5-4 are presented to illustrate the J-T methodology for determining critical flaw size as a function of load. As stated in section 5.1.1, Figure 5-3 is a typical J-integral (J) / Tearing Modulus (T) curve for the determination of the circumferential through-wall crack length. In the example shown in this figure, the flaw length is increased incrementally, and at each increment, the applied J and T are calculated using the relationships shown in Equations 5-1 through 5-5. The critical flaw length corresponds to the point on the curve where the applied load J-T curve intersects the material capacity J-T curve. This particular figure corresponds to the determination of the half critical flaw length (a) under remote bending for a stress of 25 ksi shown in Table 5-1. All the critical flaw lengths in Table 5-1 and Table 5-2 were calculated in this manner.

Figure 5-4 shows the result of a J-T evaluation for determining the critical axial through-wall flaw for a straight pipe using Equations 5-7 through 5-13. Once again, the half flaw length is increased incrementally and the applied J and T are calculated at each increment. The intersection of the applied J-T curve is the half critical flaw length, which in this example was determined to be 11.5 inches.

NRC Question 10:

Page 6-1. It is stated that 400 cycles of operating basis earthquake and 500 cycles of MSIV actuation were assumed in the fatigue crack calculation. Clarify if these cycles are consistent with the design basis.

PG&E Response to Question 10:

400 cycles of operating basis earthquake (OBE) is consistent with the DCPP Updated Final Safety Analysis Report, which in Section 3.7.3.1 states that the design basis OBE consists of 20 events of 20 cycles each. The number of MSIV actuations is not defined in the DCPP design basis documents. However, 500 cycles bounds the number of expected actuations for each DCPP unit, and has been used in the Westinghouse Steam Systems Design Manual (WCAP-7451).

NRC Question 11:

Page 6-1. Section 6.0 It seems that the fatigue crack growth is calculated based on a postulated circumferential crack. The licensee should also consider flaw growth in an axial crack in light of the seam (longitudinal) welds in the main steam pipes. Explain why an axial crack was not considered in the fatigue crack growth calculation.

PG&E Response to Question 11:

The growth of a circumferential crack is a function of the stresses applied in the direction perpendicular to the crack, i.e., the axial stresses. The growth of an axial crack is a function of the circumferential stresses. The cyclic loads affecting this system consist of seismic or MSIV bending moments, which produce axial stresses and therefore primarily affect circumferential cracks. The only load affecting axial crack length is the pressure stress. Evaluations described in section 5.2.2 of report SIR-03-146, Revision 1, found that the critical flaw sizes in the axial direction were much larger than in the circumferential direction, and the resulting leakage was significantly larger and therefore easily detectable. Thus, the potential for axial crack growth is clearly enveloped by the evaluation of circumferential crack growth.

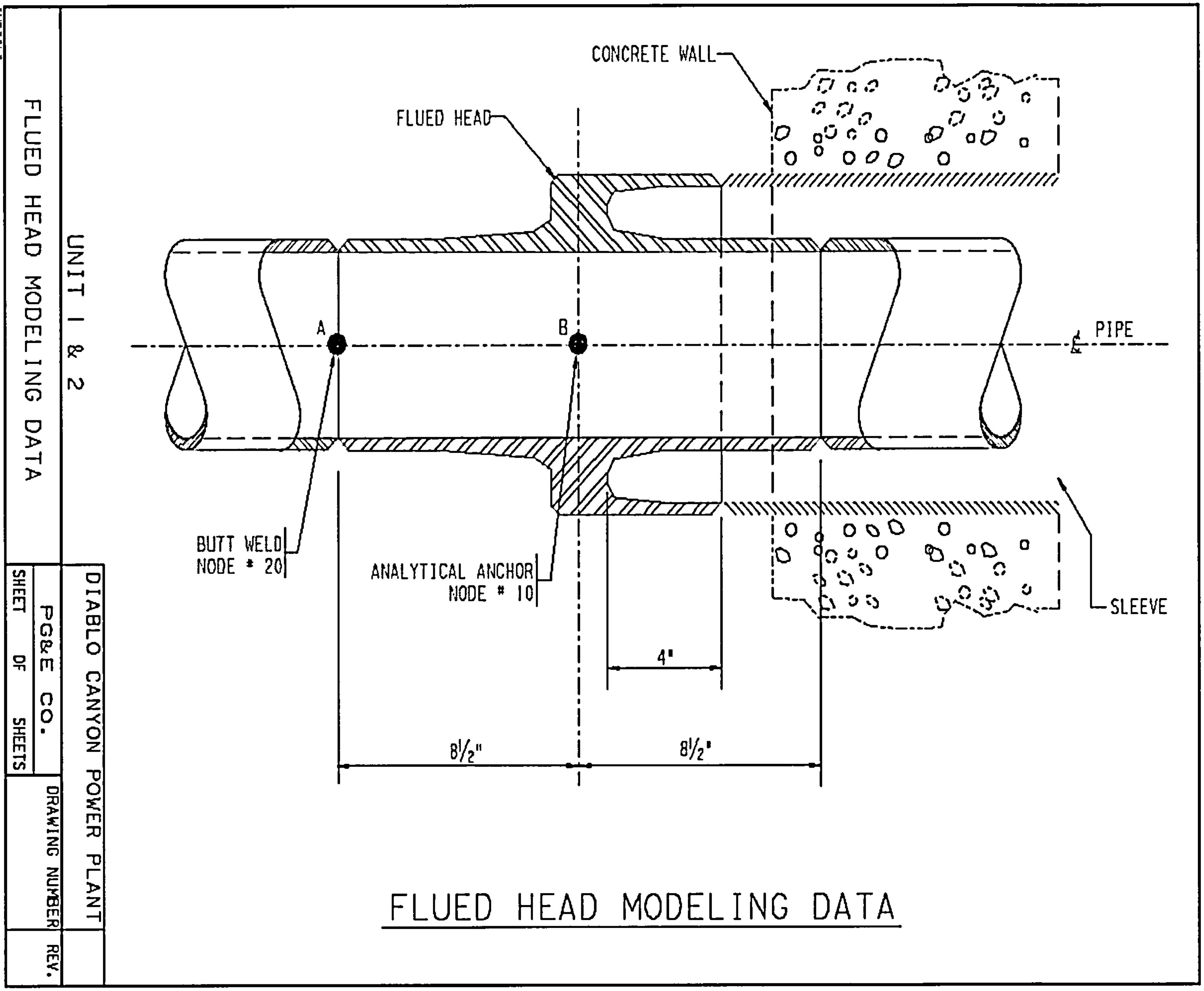
NRC Question 12:

Page 6-5. Last sentence. It is stated that the total NOP (normal operating) + SSE moment at location 10 of steam generator 1-2 is 9441 in-kips. However, location 10 and 9441 in-kips are not shown in Table 4-6, which lists all nodes and applied moments for the main steam line associated with steam generator 1-2. (a) Explain why location 10 is not included in Table 4-6 and whether the applied moment in node 10 was included in the critical crack size and leakage crack size calculations. (b) It seems that the type and magnitude of applied dynamic moments for node 10 and node 20 should be similar because node 10 is close to node 20. However, the data show that the applied moment at node 20 is dominated by the MSIV actuation loads not SSE loads whereas the applied moment at node 10 is dominated by the SSE load. Discuss the applied moments for node 10 and node 20.

PG&E Response to Question 12:

Node point 10 (and node point 130 in the Unit 2 analyses) was not included in the critical crack size and leakage calculations. The reason is that node point 10 is not a weld location, and is not even a point on the pipe – it is part of the containment penetration flued head, as shown in Figure 1. The flued head has a much larger outside diameter and is much thicker than the connecting main steam pipe. The larger cross section of the flued head indicates that any potential pipe break would preferentially occur in the main steam pipe and not in the flued head. Node point 20 is the location of the weld between the flued head and the main steam pipe, and is the last weld point on the pipe before the increased diameter of the flued head. Review of the applied moment data indicates that the moments at node points 10 and 20 are similar. Whether the MSIV or SSE loads govern varies by DCPP unit, line, and location. However, for each of the main steam lines, when the MSIV load governs at node point 10, it also governs at node point 20. On main steam lines 1-1, 1-2, and 1-4, the MSIV load governs at both node points 10 and 20. On main steam line 1-3, the SSE load governs at both points 10 and 20.

FIGURE 1


CONCRETE WALL
FLUED HEAD
A
B
PIPE
BUTT WELD
NODE # 20
ANALYTICAL ANCHOR
NODE # 10
SLEEVE
4"
8½"
8½"
FLUED HEAD MODELING DATA
UNIT 1 & 2
FLUED HEAD MODELING DATA
DIABLO CANYON POWER PLANT
PG&E CO.
SHEET OF SHEETS
DRAWING NUMBER
REV.

ENCLOSURE 2
MARKED-UP TECHNICAL SPECIFICATION PAGES

There are no changes to this page. Included for information only.

3.7 PLANT SYSTEMS

3.7.18 Secondary Specific Activity

LCO 3.7.18 The specific activity of the secondary coolant shall be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3. AND A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.18.1	Verify the specific activity of the secondary coolant is ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.	31 days

Insert new TS 3.7.19 "Main Steam Line (MSL) Leakage Detection Instrumentation" and new TS 3.7.20, "Main Steam Line (MSL) Leakage" after this page.

3.7 PLANT SYSTEMS

3.7.19 Main Steam Line (MSL) Leakage Detection Instrumentation

LCO 3.7.19 Two containment sump level monitor systems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4 when SGs are locked by expansion joints.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One containment sump level monitor system inoperable.	A.1 Place a containment fan cooler unit (CFCU) condensate collection monitor in service.	4 hours
	AND	
	A.2 Restore containment sump level monitor system to OPERABLE status.	30 days
B. Two containment sump level monitor systems inoperable with level indicators OPERABLE.	B.1 Place a CFCU condensate collection monitor in service.	4 hours
	AND	
	B.2 Perform containment sumps inventory calculation.	Once per 4 hours
	AND	
	B.3 Restore one containment sump level monitor system to OPERABLE status.	14 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two containment sump level monitor systems inoperable with level indicator(s) inoperable.	C.1 Place a CFCU condensate collection monitor in service.	4 hours
	AND	
	C.2 Perform a visual inspection of the steam lines inside containment.	Once per 72 hours
	AND	
	C.3.1 Restore one containment sump level monitor system to OPERABLE status.	7 days
	OR	
	C.3.2 Restore two containment sump level indicators to OPERABLE status.	7 days
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.19.1	Perform CHANNEL CALIBRATION of the containment sump level monitors.	24 months

3.7 PLANT SYSTEMS

3.7.20 Main Steam Line (MSL) Leakage

LCO 3.7.20 MSL leakage through the pipe walls inside containment shall be < 0.2 gpm.

APPLICABILITY: MODES 1, 2, 3, and 4 when SGs are locked by expansion joints.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. MSL leakage not within limit.	A.1 Be in MODE 3. <u>AND</u> A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.20.1	-----NOTE----- Not required to be performed until 12 hours after establishment of steady state operation. ---------- Verify MSL leakage into the containment sumps < 0.2 gpm.	72 hours

ENCLOSURE 3
RETYPED TECHNICAL SPECIFICATION PAGES

3.7 PLANT SYSTEMS

3.7.19 Main Steam Line (MSL) Leakage Detection Instrumentation

LCO 3.7.19 Two containment sump level monitor systems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4 when SGs are locked by expansion joints.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One containment sump level monitor system inoperable.	A.1	Place a containment fan cooler unit (CFCU) condensate collection monitor in service.	4 hours
	<u>AND</u>		
	A.2	Restore containment sump level monitor system to OPERABLE status.	30 days
B. Two containment sump level monitor systems inoperable with level indicators OPERABLE.	B.1	Place a CFCU condensate collection monitor in service.	4 hours
	<u>AND</u>		
	B.2	Perform containment sumps inventory calculation.	Once per 4 hours
	<u>AND</u>		
	B.3	Restore one containment sump level monitor system to OPERABLE status.	14 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Two containment sump level monitor systems inoperable with level indicator(s) inoperable.	C.1	Place a CFCU condensate collection monitor in service.	4 hours
	AND		
	C.2	Perform a visual inspection of the steam lines inside containment.	Once per 72 hours
	AND		
	C.3.1	Restore one containment sump level monitor system to OPERABLE status.	7 days
		OR	
	C.3.2	Restore two containment sump level indicators to OPERABLE status.	7 days
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.19.1	Perform CHANNEL CALIBRATION of the containment sump level monitors.	24 months

3.7 PLANT SYSTEMS

3.7.20 Main Steam Line (MSL) Leakage

LCO 3.7.20 MSL leakage through the pipe walls inside containment shall be < 0.2 gpm.

APPLICABILITY: MODES 1, 2, 3, and 4 when SGs are locked by expansion joints.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. MSL leakage not within limit.	A.1 Be in MODE 3. <u>AND</u> A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.20.1	----------NOTE---------- Not required to be performed until 12 hours after establishment of steady state operation. ------------------------------ Verify MSL leakage into the containment sumps < 0.2 gpm.	72 hours

ENCLOSURE 4
MARKED-UP TECHNICAL SPECIFICATION BASES PAGES
(for information only)

B 3.7 PLANT SYSTEMS

B 3.7.19 Main Steam Line (MSL) Leakage Detection Instrumentation

BASES

BACKGROUND

Leakage detection instrumentation to detect MSL leakage inside containment is required to detect the presence of main steam piping leakage. Detection of main steam piping leakage is required to support the MSL Leak-Before-Break (LBB) analysis discussed in Updated Final Safety Analysis report section 5.5.2.5.4 (Reference 1) which was assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. 10 CFR 50 Appendix A General Design Criteria 4 (Reference 2) allows the use of advanced technology to exclude from structural design consideration the dynamic effects of pipe ruptures in nuclear plants, provided it is demonstrated that the probability of pipe rupture is extremely low under conditions consistent with the design bases for the piping. The demonstration of low probability of pipe rupture utilizes a deterministic fracture mechanics analysis that evaluates the stability of postulated, small, through-wall flaws in piping and the ability to detect leakage through the flaw long before the flaw could grow to unstable sizes and rupture the pipe. The concept underlying these analyses is referred to as LBB. The limitations and acceptance criteria for LBB are discussed in NUREG-1061, Volume 3 (Reference 3). The NUREG-1061, Volume 3, guidelines specify that there is the capability to detect leakage from piping in which LBB has been applied and that there is a factor of 10 between the leakage detection capability and the leakage which would result from the LBB analysis leakage crack when the pipe is subjected to normal operational loads.

The MSL leakage detection instrumentation system must have the capability to detect significant main steam piping degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. To meet the NUREG-1061, Volume 3, guideline of a factor of 10 between the leakage detection capability and the leakage from the LBB analysis leakage crack, the MSL leakage detection instrumentation system must be capable of detecting 0.2 gpm.

The two containment sumps used to collect containment leakage, are instrumented to provide an alarm in the control room for increases of greater than or equal to 0.2 gpm in the normal leakage inside containment. Since there is no other TS required method to quantify steam piping leakage inside containment in a short time frame, two sump level monitor systems are required to be OPERABLE.

(continued)

BASES

BACKGROUND (continued)	The containment fan cooler unit (CFCU) condensate collection monitor, that may be OPERABLE to meet TS 3.4.15.c, provides a diverse system that can detect a 0.2 gpm leak inside containment. Any one of these three systems is capable of detecting a 0.2 gpm steam leak inside containment. The containment sump level indicators and plant process computer are highly reliable and are capable of detecting main steam line leakage. During times when the plant process computer is unavailable, the CFCU condensate collection monitor can be placed in service to assure timely detection and a sump inventory balance can be performed to provide redundant monitoring of containment sump inflow. The sensitivity of the sump level measurement instrumentation is sufficient to detect the level change associated with a 0.2 gpm leak, accounting for all possible fan cooler alignments. The CFCU condensate collection monitor is also capable of detecting a 0.2 gpm steam leak. The leakage detection instrumentation to detect MSL leakage inside containment is only required while LBB is applied to the MSL piping to support the TS 5.5.9.d.1.j(i) SG 4-volt lower voltage repair limit.
APPLICABLE SAFETY ANALYSES	The TS 5.5.9.d.1.j(i) SG 4-volt lower voltage repair limit is based on limited SG tube support plate displacement following a MSL break downstream of the flow restrictor in the MSL (small MSL break). The flow restrictor is located in the SG steam line downstream of the SG nozzle. The area of the MSL pipe on either side of the flow restrictor is the same, however if a MSL break occurs downstream of the flow restrictor the dynamic effects of the break are limited since the break size is limited to the area of the flow restrictor. A MSL break upstream of the flow restrictor (large MSL break) is not impacted by the flow restrictor and the MSL break size is the area of the MSL pipe. Large MSL breaks were not considered due to application of LBB to the MSL piping. The SG alternate repair criteria based on limited tube support plate displacement is described in Westinghouse Report WCAP-16170-P, Revision 0 (Reference 4). The limited tube support displacement is based on SG tube expansion joints that are applied at the tube support plate locations. The SG tube expansion joints mechanically lock the tube support plates in place. SGs which have tube expansion joints mechanically locking the tube support plates in place are referred to as locked SGs. The number of SG tube expansion joints which are required to limit the tube support plate displacement following a MSL break depends on the fluid loads on the tube support plate following

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	the break, which in turn depends on the size of the break. The analyses in WCAP-16170-P, Revision 0, are based on a small MSL break downstream of the flow restrictor in the MSL. Large MSL breaks upstream of the flow restrictor were precluded by application of LBB to the MSL piping. MSL leakage detection instrumentation satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii) since it is required as part of the analysis basis for the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit, in which large MSL breaks upstream of the flow restrictor were precluded by application of LBB to the MSL piping.

LCO

To protect against a main steam pipe flaw growing to an unstable size resulting in rupture of the pipe, MSL leakage detection instrumentation is required. This LCO requires two redundant containment sump level monitor systems to be OPERABLE to provide a high degree of confidence that small MSL leaks are detected in time to allow action to place the plant in a safe condition when MSL leakage exists.

Each OPERABLE containment sump level monitor system consists of a containment sump, an operating CFCU aligned to the sump, a level indicator, and a level monitoring computer that provides a control room alarm. The table below identifies the required equipment for each OPERABLE containment sump level monitor system.

Sump	1	2
Operating CFCU	1, 2, or 3	4 or 5
Level Indicator	LI-60	LI-61
Level monitoring computer with control room alarm capability	plant process computer or equivalent	plant process computer or equivalent

APPLICABILITY

In MODES 1, 2, 3, and 4 when the SGs are locked by expansion joints, the MSL leakage detection instrumentation is required to be OPERABLE in the event that a small MSL pipe flaw occurs. The MSL leakage detection instrumentation is only required to support application of LBB to the MSL piping for a unit which has SGs locked by expansion joints as described in TS 5.5.9.b.4. Leakage detection instrumentation to detect MSL leakage inside containment is required to support the MSL Leak-Before-Break (LBB) analysis assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. The SGs are required to be OPERABLE as part of an OPERABLE RCP loop in MODES 1 and 2 per TS 3.4.4, MODE 3 per TS 3.4.5, and MODE 4 per TS 3.4.6. In MODE 5, the SGs cannot produce steam.

(continued)

BASES

ACTIONS

A.1 and A.2

With one of the two required containment sump level monitor systems inoperable, the one remaining OPERABLE containment sump level monitor system is sufficient for MSL leakage detection. To provide a diverse method to identify and quantify MSL leakage, a CFCU condensate collection monitor OPERABLE per TS 3.4.15.c must be placed in service within 4 hours per ACTION A.1. Four hours provides time to place a CFCU condensate collection monitor in service and restricts the time of operation with only one OPERABLE MSL leakage detection system.

Restoration of the containment sump level monitor system to OPERABLE status is required to regain the function in a Completion Time of 30 days. This time is acceptable, considering the diverse method to quantify MSL leakage provided by the associated CFCU condensate collection monitor that is placed in service.

B.1, B.2, and B.3

With two of the two required containment sump level monitor systems inoperable with level indicators OPERABLE, the redundant capability of the containment sump level monitor system is lost. However, a CFCU condensate collection monitor can be placed in service to provide MSL leakage detection capability. To provide two diverse methods of identifying MSL leakage, a CFCU condensate collection monitor must be placed in service and a containment sumps inventory calculation must be performed every four hours. Four hours provides time to place the CFCU condensate collection monitor in service, to perform the containment sumps inventory calculation, and restricts operation with no redundant MSL leakage detection systems. The containment sumps inventory calculation is performed by performing the Containment Sumps' Inventory and Discharge Evaluation contained of surveillance test procedure STP I-1A (Reference 5).

Restoration of one containment sump level monitor system to OPERABLE status is required in a Completion Time of 14 days. This time is acceptable, when considering the diverse method to detect MSL leakage provided by the CFCU condensate collection monitor that is placed in service and the containment sumps inventory calculation that is performed every 4 hours.

(continued)

BASES

ACTIONS (continued)

C.1, C.2, C.3.1, and C.3.2

With two of the two required containment sump level monitor systems inoperable with level indicator(s) inoperable, the capability to detect leakage through containment sump level instrumentation is lost. To provide a diverse method to identify MSL leakage, the associated CFCU condensate collection monitor must be placed in service within four hours and a visual inspection of the steam lines inside containment must be performed once every 72 hours. Four hours provides time to place the CFCU condensate collection monitor in service.

The 72 hour interval for the visual inspection of the steam lines inside containment provides a diverse method to detect MSL leakage from the CFCU condensate collection monitor and provides periodic information that is adequate to detect MSL leakage. The 72 hour interval is acceptable based on the diverse method to detect MSL leakage from the CFCU condensate collection monitor which is placed in service. With a CFCU condensate collection monitor placed in service within four hours and a visual inspection of the steam lines inside containment performed once every 72 hours, one containment sump level monitor system must be restored to OPERABLE status within 7 days or two containment sump level indicators must be restored to OPERABLE status within 7 days.

The 7 day Completion Time is acceptable considering the diverse method to detect MSL leakage from the CFCU condensate collection monitor and the additional visual inspection of the steam lines inside containment performed every 72 hours.

D.1 and D.2

If a REQUIRED ACTION of CONDITION A, B, or C cannot be met within the required Completion Time, the reactor must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.19.1 Performing a CHANNEL CALIBRATION of the two containment sump level monitor system channels verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 24 months is consistent with the refueling cycle and considers channel reliability. Operating experience has proven that this Frequency is acceptable.
REFERENCES	1. FSAR, Section 5.5.2.5.4, Voltage-based Alternate Repair Criteria. 2. 10 CFR 50 Appendix A General Design Criterion 4, 52 FR 41288; October 27, 1987. 3. NUREG-1061, Volume 3, "Evaluation of Potential for Pipe Breks, Report of the U.U. Nuclear Regulatory Commission Piping Review Committee," dated November 1984. 4. WCAP-16170-P, Revision 0, "Diablo Canyon SG Alternate Repair Criteria Based On Limited Tube Support Plate Displacement," dated November 2003. 5. Surveillance Test Procedure STP I-1A, "Routine Shift Checks Required by Licenses".

B 3.7 PLANT SYSTEMS

B 3.7.20 Main Steam Line (MSL) Leakage

BASES

BACKGROUND

A limit on leakage from the main steam line (MSL) inside containment is required to limit system operation in the presence of excessive leakage. Leakage is limited to an amount which would not compromise safety consistent with the MSL Leak-Before-Break (LBB) analysis discussed in Updated Final Safety Analysis report section 5.5.2.5.4 (Reference 1) which was assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. This leakage limit ensures appropriate action can be taken before the integrity of the lines is impaired.

10 CFR 50 Appendix A General Design Criteria 4 (Reference 2) allows the use of advanced technology to exclude from structural design consideration the dynamic effects of pipe ruptures in nuclear plants, provided it is demonstrated that the probability of pipe rupture is extremely low under conditions consistent with the design bases for the piping. The demonstration of low probability of pipe rupture utilizes a deterministic fracture mechanics analysis that evaluates the stability of postulated, small, through-wall flaws in piping and the ability to detect leakage through the flaw long before the flaw could grow to unstable sizes and rupture the pipe. The concept underlying these analyses is referred to as LBB. The limitations and acceptance criteria for LBB are discussed in NUREG-1061, Volume 3 (Reference 3). The NUREG-1061, Volume 3, guidelines specify that there is the capability to detect leakage from piping in which LBB has been applied and that there is a factor of 10 between the leakage detection capability and the leakage which would result from the LBB analysis leakage crack when the pipe is subjected to normal operational loads.

LBB has been applied to the MSL pipes inside containment as part of the analysis basis for the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. The potential safety significance of large MSL breaks inside containment require detection and monitoring of leakage inside containment. This LCO protects the MSLs inside containment against degradation, and helps assure that large MSL breaks inside containment will not develop. The consequences of violating this LCO include the possibility of further degradation of the main steam lines, which may lead to a large MSL break, and invalidation of the analysis basis for the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The safety significance of plant leakage inside containment varies depending on its source, rate, and duration. Therefore, detection and monitoring of plant leakage inside containment are necessary. This is accomplished by instrumentation required by TS LCO 3.4.15, "RCS Leakage Detection Instrumentation," for the reactor coolant system (RCS) and TS LCO 3.7.19, "Main Steam Line (MSL) Leakage Detection Instrumentation," for the MSLs. The two containment sumps used to collect containment leakage, are instrumented to provide an alarm in the control room for increases of greater than or equal to 0.2 gpm in the normal leakage inside containment. Use of the RCS Leakage detection instrumentation information, and any other available information, provides qualitative information to the operators regarding possible main steam line leakage. This allows the operators to take corrective action should leakage occur which is detrimental to the safety of the facility and/or the public.

The TS 5.5.9.d.1.j(i) SG 4-volt lower voltage repair limit is based on limited SG tube support plate displacement following a MSL break downstream of the flow restrictor in the MSL (small MSL break). The flow restrictor is located in the SG steam line downstream of the SG nozzle. The area of the MSL pipe on either side of the flow restrictor is the same, however if a MSL break occurs downstream of the flow restrictor the dynamic effects of the break are limited since the break size is limited to the area of the flow restrictor. A MSL break upstream of the flow restrictor (large MSL break) is not impacted by the flow restrictor and the MSL break size is the area of the MSL pipe. Large MSL breaks were not considered due to application of LBB to the MSL piping.

The SG alternate repair criteria based on limited tube support plate displacement is described in Westinghouse Report WCAP-16170-P, Revision 0 (Reference 4). The limited tube support displacement is based on SG tube expansion joints that are applied at the tube support plate locations. The SG tube expansion joints mechanically lock the tube support plates in place. SGs which have tube expansion joints mechanically locking the tube support plates in place are referred to as locked SGs. The number of SG tube expansion joints which are required to limit the tube support plate displacement following a MSL break depends on the fluid loads on the tube support plate following the break, which in turn depends on the size of the break. The analyses in WCAP-16170-P, Revision 0, are based on a small MSL break downstream of the flow restrictor in the MSL. Large MSL breaks upstream of the flow restrictor were precluded by application of LBB to the MSL piping.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The MSL leakage limit satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii) since it is required as part of the analysis basis for the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit, in which large MSL breaks upstream of the flow restrictor were precluded by application of LBB to the MSL piping.
LCO	Main steam line leakage is defined as leakage inside containment from any portion of the four main steam line pipe walls. Fluid loss from components in or connected to the main steam line is not main steam line leakage. Less than 0.2 gpm of leakage is allowable because it is less than one tenth (0.1) of the calculated leakage from the LBB analysis leakage crack. The NUREG-1061, Volume 3, guideline specifies a factor of 10 between the leakage detection capability and the leakage from the LBB analysis leakage crack. Violation of this LCO constitutes an unacceptable reduction in safety margin.
APPLICABILITY	In MODES 1, 2, 3, and 4 when the SGs are locked by expansion joints, the MSL leakage limit is APPLICABLE. The MSL leakage limit is only required to support application of LBB to the MSL piping for a unit which has SGs locked by expansion joints as described in TS 5.5.9.b.4. The MSL leakage limit inside containment is required to support the MSL Leak-Before-Break (LBB) analysis assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit. The SGs are required to be OPERABLE as part of an OPERABLE RCP loop in MODES 1 and 2 per TS 3.4.4, MODE 3 per TS 3.4.5, and MODE 4 per TS 3.4.6. In MODE 5, the SGs cannot produce steam.
ACTIONS	A.1 and A.2 With the MSL leakage in excess of the LCO limit, the reactor must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.7.20.1 Verifying that MSL leakage is within the LCO limit assures the integrity of those lines inside containment is maintained. Information from the Containment Sumps' Inventory and Discharge Evaluation performed per surveillance test procedure STP I-1A (Reference 5) is used to verify the MSL leakage is less than 0.2 gpm. When the total change in sump inventory is greater than 0.2 gpm, MSL leakage must be confirmed to be less than 0.2 gpm by use of other containment leak detection methods. Information from the Containment Sumps' Inventory and Discharge Evaluation, the RCS water inventory balance performed per SR 3.4.13.1, and the RCS leakage detection

BASES

SURVEILLANCE REQUIREMENTS (continued)	instrumentation required by TS 3.4.15, is used to determine whether the main steam line is a potential source of leakage inside containment. An early warning of main steam line leakage is provided by the two containment sumps used to collect containment leakage, which are instrumented to provide an alarm in the control room for increases of greater than or equal to 0.2 gpm in the normal leakage inside containment. The alarm could be due to leakage from any system or component which can leak into containment, and leakage due to the MSL is most likely positively identified by inspection. For the RCS water inventory balance performed per SR 3.4.13.1, the reactor must be at steady state operating conditions (stable temperature, power level, pressurizer level, makeup and letdown, and reactor coolant pump seal injection flows). Therefore, consistent with SR 3.4.13.1, a Note is added allowing that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established. Steady state operation is required to perform a proper RCS inventory balance since calculations during maneuvering are not useful. The Frequency of 72 hours is a reasonable interval to trend leakage and recognizes the importance of early leakage detection to support the MSL LBB analysis assumed as part of the TS 5.5.9.d.1.j(i) steam generator (SG) 4-volt lower voltage repair limit.

REFERENCES

1. FSAR, Section 5.5.2.5.4, Voltage-based Alternate Repair Criteria.
2. 10 CFR 50 Appendix A General Design Criterion 4, 52 FR 41288; October 27, 1987.
3. NUREG-1061, Volume 3, "Evaluation of Potential for Pipe Breaks, Report of the U.U. Nuclear Regulatory Commission Piping Review Committee," dated November 1984.
4. WCAP-16170-P, Revision 0, "Diablo Canyon SG Alternate Repair Criteria Based On Limited Tube Support Plate Displacement," dated November 2003.
5. Surveillance Test Procedure STP I-1A, "Routine Shift Checks Required by Licenses".

ENCLOSURE 5
REVISED TABLE 4-12 PAGE 4-18
OF STRUCTURAL INTEGRITY ASSOCIATES, INC.,
REPORT NO. SIR-03-146, REVISION 1,
"LEAK-BEFORE-BREAK EVALUATION MAIN STEAM PIPING INSIDE CONTAINMENT DIABLO CANYON POWER PLANT UNITS 1 AND 2,"
DATED DECEMBER 2003

Table 4-12

Moments for DCPP Unit 2 Main Steam 2-4

Node #	NOP (in-kips)	NOP+DYN (in-kips)
5	1104.7	4651.8
7 M	1099.9	4440.9
8	1095.3	3958.5
9 B	1095.3	3956.4
9 M	1101.7	3321.4
19	1117.3	3041.9
20	1133.7	2828.8
24	1146.7	2739.2
24A	1274.1	2497.1
30	1489.5	2688.3
31	1587.2	2834.0
35	1802.5	3169.9
40M	2023.1	3434.8
45	1943.1	2992.7
46	1897.9	2831.5
47	1492.4	2585.1
47A	1182.3	3231.0
50	873.4	4190.3
55	828.8	4344.7
65	690.6	4839.7
70	540.2	5412.8
70A	265.0	4933.4
75	163.5	4727.6
79	538.8	3848.4
80	582.6	3769.8
85	744.7	3503.0
85A	1109.6	3049.3
85B	1476.9	2825.5
90	1845.1	3274.0
95 B	2040.9	3488.8
95 M	2151.1	3123.0
95 E	1947.8	4397.6
101	1724.3	4958.8
106	1362.2	3818.8
110	1286.8	3620.6
110A	423.6	3332.7
120	696.0	6047.3

NOP = Normal operating load = Dead Weight and Thermal Expansion Loads at 100% power
DYN = Dynamic loads consisting of either SSE loads or MSIV loads, whichever is greater