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PG&E Letter DCL-03-178

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
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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 NRC Request for Additional Information Regarding License Amendment Request 03-07, "Revision to Technical Specifications (TS) 3.8.1 "AC Sources – Operating" & 3.8.4 "DC Sources – Operating" Surveillance Requirements"

Dear Commissioners and Staff:

Pacific Gas and Electric (PG&E) Letter DCL-03-061, dated May 29, 2003, submitted License Amendment Request (LAR) 03-07, "Revision to Technical Specifications (TS) 3.8.1 'AC Sources – Operating' & 3.8.4 'DC Sources – Operating,' Surveillance Requirements," which allows surveillance testing of the onsite standby emergency diesel generators (EDG) during modes in which it is currently prohibited and incorporates changes included in NRC-approved Technical Specification Task Force (TSTF) Standard Technical Specification change TSTF-283, Revision 3. PG&E submitted LAR 03-07 in conjunction with an industry consortium of six plants as a result of a mutual agreement known as Strategic Teaming and Resource Sharing (STARS). The STARS group consists of the six plants operated by TXU Generation Company LP, Union Electric Company, Wolf Creek Nuclear Operating Corporation, Pacific Gas and Electric Company, STP Nuclear Operating Company, and Arizona Public Service Company. Three members of the group, Union Electric Company, Wolf Creek Nuclear Operating Corporation, and Arizona Public Service Company provided concurrent LAR submittals. The concurrent submittals were intended to allow the NRC to review these submittals as a group.

On September 25, 2003, the NRC staff requested additional information concerning all four of these STARS submittals. PG&E's responses to the staff's questions are provided in Enclosure 1. These responses were discussed with the NRC on November 19, 2003. In that discussion the NRC expressed concern with the proposed revision to the Notes in Surveillance Requirement (SR) 3.8.4.7 and SR 3.8.4.8, which provide the flexibility for a partial performance of the SRs to reestablish OPERABILITY following corrective maintenance. The inclusion of the changes to the Notes in SR 3.8.4.7 and SR 3.8.4.8 is consistent with NRC approval of TSTF-283. The NRC's concern was that the proposed TSTF changes to

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SR 3.8.4.7 and SR 3.8.4.8, allowing portions of these surveillances to be performed at power, could result in a partial discharge of the batteries, which would not be acceptable. As a result of further discussions with the lead NRC Project Manager, Pacific Gas and Electric Company is providing responses to all the Requests for Additional Information. PG&E has agreed with the lead NRC Project Manager to have the Staff process separately the proposed changes to SR 3.8.4.7 and SR 3.8.4.8 to allow timely issuance of the license amendment for the remaining requested changes and to allow additional time to resolve the concern with the partial testing both generically for the industry and for Diablo Canyon Power Plant.

This information does not affect the results of the technical evaluation and no significant hazards consideration determination previously transmitted in PG&E Letter DCL-03-061.

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

Dxs/4540
Enclosures
cc: Edgar Bailey, DHS
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David L. Proulx
Diablo Distribution
cc/enc: Girija S. Shukla

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 03-07 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 23rd day of December, 2003.

Notary Public
County of San Luis Obispo
State of California

SANDRA L. RECTOR
Commission # 1339380
Notary Public - California
San Luis Obispo County
My Comm. Expires Jan 12, 2006

PG&E Response To NRC Requests For Additional Information Regarding License Amendment Request 03-07, "Revision To Technical Specifications (TS) 3.8.1 'AC Sources – Operating' & 3.8.4 'DC Sources – Operating' Surveillance Requirements"

In the NRC's request for additional information they provided a series of questions, which included questions that required answers by all four plants including Diablo Canyon Power Plant (DCPP) and some questions which were specific to one plant. The common questions are 1a, 1b, 1c, 1d, 1e, 1f, and 1g. The DCPP specific questions are 3a and 3b. DCPP was not requested to respond to any of the additional questions. The following are restatements of the NRC questions DCPP was to respond to, followed by DCPP's response.

NRC Question 1a:

Surveillance Requirement (SR) 3.8.4.7 and SR 3.8.4.8 contain a Note that has been modified to add "However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced." Provide the intent of this note in detail (what exactly will be done at power, the duration of these surveillances and its impact on the limiting condition of operation, details regarding assessment, etc.)

PG&E's Response:

Surveillance Requirement (SR) 3.8.4.7 and SR 3.8.4.8 are the DC battery service test and the DC battery discharge test, respectively. In practice, this allowance provided by the revised Note will not likely be utilized since the battery service or performance discharge test require many hours to perform and the battery is inoperable during this testing. Partial performance of the battery service or performance discharge test is also unlikely given the intrusive nature of the test and the fact that partial performance would likely not be useful except under unusual circumstances. Additionally, partial performance of the SRs may present a challenge to the two-hour Completion Time specified for restoration of an inoperable battery per Required Action A.1 of limited condition for operation (LCO) 3.8.4.

The proposed revision to the Note was included in these SRs to provide the flexibility for a partial performance test to reestablish operability following corrective maintenance. The inclusion of the changes to the Notes in SR 3.8.4.7 and SR 3.8.4.8 is consistent with NRC approval of Technical Specification Task Force (TSTF)-283, Revision 3.

The responses to the Request for Additional Information were discussed with the NRC on November 19, 2003. Additional discussions were held with the lead NRC Project Manager regarding the NRC concerns that the proposed TSTF changes to SR 3.8.4.7 and SR 3.8.4.8 allowing portions of these surveillances to be performed at power could

result in a partial discharge of the batteries. PG&E is in agreement with the lead NRC Project Manager to process separately the proposed changes to SR 3.8.4.7 and SR 3.8.4.8.

NRC Question 1b:

Do the work control programs, risk management programs, and/or procedures cover a comprehensive walk-down just prior to entering the period of reduced equipment availability during EDG testing? Provide details about the walk-down or justify why such walk-down is not required.

PG&E's Response:

Any planned activity that potentially results in a reduced level of equipment availability is not undertaken unless the status of the equipment potentially affected is known and all redundant equipment is in a condition that precludes any unacceptable risk from performing such an activity. The procedures controlling such activity require determination of the status of all potentially affected systems, communication with responsible operation and maintenance personnel, and the placement of formal clearances, if necessary. The determination of the status of systems may involve review of the plan of the day to determine potential activities that could adversely affect the planned activity or increase the risk, walkdowns of the components or system being affected and the backups to those being affected, and review of offsite or external conditions that could have a potential affect on the risk (i.e., grass fires, severe weather or other grid related transients or scheduled work activities). Tailboards would take place with the various onsite operations and maintenance organizations to ensure complete understanding of the activity and to ensure no other activities take place that could adversely affect the plant through the duration of the activity being performed. Prior to the activity, clearances would be implemented on the equipment and systems that are being removed from service for the testing. This would involve walkdowns and verification by operations and maintenance personnel. However, for components and systems that potentially could be affected by the testing, but are not part of the testing clearance, there are various ways of determining status as discussed above, and walkdowns are not always a requirement. For those components or systems outside of the test clearance, if the status are not readily verifiable a walkdown would be performed.

NRC Question 1c:

Indicate where the loss-of-offsite power signal comes from when the EDG is powering, or is paralleled to, the safety bus.

PG&E's Response:

The loss-of-power relays sense voltage from the 4.16 kV safety buses. This is the case whether an emergency diesel generator (EDG) is or is not powering its associated bus and whether the EDG is paralleled or not paralleled to the off-site power source.

NRC Question 1d:

Discuss administrative controls to preclude performing these surveillances during other maintenance and test conditions that could have adverse effects on the offsite power system or plans for restricting additional maintenance or testing of required safety systems that depend on the remaining EDG as a source. Additionally, discuss if the remaining EDG were to become inoperable while the other EDG is being tested, would the test be aborted.

PG&E's Response:

At DCPP, no test is undertaken unless the status of the equipment being tested is known, and all redundant or potentially affected equipment is in a condition that precludes unacceptable risk from performing such a test. All of the testing activities require determination of the status of potentially affected systems, communication with responsible operation and maintenance personnel, and the placement of formal clearances, if necessary. The determination of the status of systems may involve the review of the plan of the day to determine potential activities that could adversely affect the test or increase risk, walkdowns of the components or system being tested and the backups to those being tested, and review of offsite or external conditions that could have a potential affect on the risk (i.e., grass fires, severe weather or other grid related transients or scheduled work activities). Tailboards would take place with the various onsite operations and maintenance organizations to ensure a complete understanding of the testing activity and to ensure no other activities take place that could adversely affect the testing or the plant during the testing. In addition, prior to the testing, clearances would be placed and verified by operations and maintenance personnel involved in the testing.

The switchyard at DCPP is not operated or controlled by plant staff, however, there are formal communication processes and agreements in place that limit risk related work in the switchyard during diesel testing.

During the testing activities, if a redundant system or component became inoperable, a decision to abort the test would be made based on current plant conditions, the purpose for performing the test, and whether increase in risk is involved. In some cases it may

be prudent to complete the test, e.g., if the test is being performed to reestablish operability following corrective maintenance. However, in most cases the test would be aborted, and the affected systems returned to service immediately.

DCPP Administrative Procedure AD7.DC6, "On-Line Maintenance Risk Management" is provided in Enclosure 2. This procedure includes the verification procedures and processes that are followed for all on-line activities including testing. This procedure provides guidance for evaluating risk in accordance with 10 CFR 50.65(a)(4) (Maintenance Rule), establishing compensatory measures, and assuring the activity is scheduled in the appropriate train/bus/set workweek.

NRC Question 1e:

Discuss whether procedures are in place to alert operators when to perform either portions or full SRs/Testing. Will the operators receive training on the procedures related to the proposed technical specification changes prior to implementation?

PG&E's Response:

All testing at DCPP, whether normal full testing or partial testing, is performed using approved procedures. All operations and maintenance personnel are trained and knowledgeable of the associated procedures prior to performing them. Partial testing is not considered to be a normal testing activity, and the parameters or boundaries of the test may vary. As a result, partial tests may require a special test procedure be created specifically for that test.

The decision on whether to perform one (or more) of these SRs, either in full or partially, would be determined based on the specific corrective maintenance being performed. The cause of the failure that results in the need to perform corrective maintenance has to be known in order to determine what testing would be required in order to reestablish operability. This process is established in plant procedures on work controls and addresses emergent work. Emergent work is unforeseen or unexpected work requiring immediate attention, which may require 24-hour coverage due to potential impact on the safe, reliable, and legal operation of the plant. At a minimum, all issues causing unplanned entry into a technical specification equipment outage of 72 hours or less would be considered emergent. For emergent work activities, key personnel are identified as having the responsibility for providing input into the required repairs and testing necessary to restore operability. The identified surveillance testing requirements for any work would be specifically provided or referenced in the work orders for performing the corrective maintenance or modification. The work orders and the plant procedures associated with the identified surveillance testing, specify responsibilities for ensuring required surveillance tests are completed prior to declaring a system/component operable. These procedures take into consideration the proper plant conditions for the testing, require briefings with the test performer on the effect of the testing on plant equipment, and assure the testing will not place the plant in an unsafe condition.

As a normal part of the implementation process for any approved technical specification change all required procedures must be in place and all personnel directly affected by those changes must be trained on the procedures and changes prior to implementation. This training can involve mentoring, tailboards, and/or formal training.

NRC Question 1f:

Discuss the compensatory measures that will be implemened during performance of SRs 3.8.1.10, 3.8.1.13, and 3.8.1.14.

PG&E's Response:

All of the testing activities at DCPP require determination of the status of potentially affected systems, communication with responsible operation and maintenance personnel, and the placement of formal clearances, if necessary. The determination of the status of systems may involve the review of the plan of the day to determine potential activities that could adversely affect the test or increase risk, walkdowns of the components or systems being tested and the backups to those being tested, and review of offsite or external conditions that could have a potential affect on the risk (i.e., grass fires, severe weather or other grid related transients or scheduled work activities). Tailboards would take place with the various onsite operations and maintenance organizations to ensure complete understanding of the testing activity and to ensure no other activities take place that could adversely affect the testing or the plant during the testing. In addition prior to the testing, clearances would be placed and verified by operations and maintenance personnel involved in the testing.

The compensatory measures for these specific tests include verifying the plant conditions, evaluating the risk, communicating to plant personnel, placing clearances, ensuring the redundant EDGs are operable and remain operable during this testing, and ensuring other activities do not take place that could adversely affect the plant through the duration of the activity being performed.

NRC Question 1g:

For SR 3.8.1.13, discuss (1) how the SR is performed and (2) how the safety injection (SI) signal is generated without disturbing power operation.

PG&E's Response:

The current approved wording of DCPP SR 3.8.1.13 is somewhat different from NUREG 1431 and TSTF-283. It does not specifically require that verification of bypass capability be tested for an actual or simulated loss of bus voltage concurrent with a safety injection (SI) signal. The DCPP EDG start logic is designed such that all EDG trip functions, with the exceptions listed in the technical specification (TS), are bypassed when the EDG is started automatically (on loss of standby power or SI signal, or both),

the cutout switch is in the cutout position and the EDG is aligned for automatic operation. The continuity test across the switches ensures that there is no signal across these switches that would allow these trip functions to function and trip the EDG during an automatic start. The verification of no signal when the switches are in the cutout position ensures that these trip functions will be properly bypassed and the system will function properly for any single or combination of the start signals. EDG automatic start on an actual or simulated loss of bus voltage concurrent with a SI signal is verified in DCPP SR 3.8.1.11 and SR 3.8.1.12.

1) The SR 3.8.1.13 test involves turning a toggle switch on the vertical board to "cut-out" position and verifying that there is no continuity across the switch contacts. The toggle switch is also turned to "cut-in" position and it is verified that there is continuity across the switch contacts.

2) This surveillance test does not require an SI signal to be generated. However at DCPP, any surveillance test procedures that are performed, including start of the EDG on a SI signal, are performed from the solid state protection system (SSPS) test cabinet, which has switches controlling associated slave relays. Those switches are turned to the test position and then depressed to simulate the SI signal for particular equipment, i.e., EDG. Currently we start the EDGs on a quarterly frequency from SSPS by simulating a SI signal.

NRC Question 3a

For SR 3.8.1.10, in Section 4.1 of the application, it is stated that "during the last refueling outage at DCPP [Diablo Canyon Power Plant] when the DG full load reject SRs were performed for each diesel, the voltage transients experienced by the loads on the associated buses were minor (the worst case was an approximate 1.29 percent change of 54 volts in the bus voltage at the 4.16 kV level, in approximately 0.09 seconds)." Discuss the impact of this voltage transient on degraded voltage relays. Also, during power operation the voltages at the safety buses are relatively lower than during shutdown, what will be the voltage transient due to a full load rejection test at the lower voltages and its impact on degraded voltage relays?

NRC Question 3b

Question a above is also applicable to SR 3.8.1.14.

PG&E's Response for 3a and 3b:

The impact of this momentary voltage transient on the degraded voltage relays will be negligible regardless of whether it is during an outage at higher bus voltages or during plant operation at lower (normal) bus voltages. The bus transient voltage of 54V is the difference between an EDG paralleled to the bus and offsite power, versus the offsite power voltage level. The transient voltage is the boost to the bus voltage from the associated EDG. Once the EDG output breaker is opened during load rejection, the

bus voltage decays to the offsite power voltage level. During the subject testing, no bus voltage oscillation was observed when taking this data with high-speed recorders and the transition was smooth with no step change.

The degraded bus voltage relays (27HFB3 and 27HFB4) are set to drop out at 109.5 V (equivalent bus voltage of 3810 V) and 109 V (equivalent bus voltage of 3827 V), respectively. These relays, when actuated, send output signals through time delay relays: 10sec (62HF3A) to start the EDG, and 20 sec (62HF3B) to initiate load shed. The momentary 54 V transient would appear to these relays as a bus voltage drop from approximately 4210 V with the EDG connected, to approximately 4160 V, which would not actuate or have an affect on these relays.

Diablo Canyon Power Plant Administrative Procedure AD7.DC6, "On-Line Maintenance Risk Management"

TITLE: On-Line Maintenance Risk Management

10/24/02
EFFECTIVE DATE

PROCEDURE CLASSIFICATION: QUALITY RELATED
SPONSORING ORGANIZATION: OPERATIONS
REVIEW LEVEL: "A"

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1. SCOPE

1.1 This procedure provides guidance for managing plant trip, probabilistic, and safety function degradation risk from on-line maintenance, external or internal conditions, as required by 10 CFR 50.65(a)(4) of the Maintenance Rule.

1.2 These instructions shall be used for risk management when the unit is in MODES 1, 2, 3 and 4. Risk management in MODES 5 and 6 is addressed in AD8.DC50 through AD8.DC55.

1.3 Risk in the transitional MODE 4 will be controlled as follows:

1.3.1 Any maintenance on risk significant Systems, Structures, or Components (SSCs) in MODE 4 will require specific authorization of the operations manager.

1.3.2 Risk significant equipment removed from service in accordance with Tech Spec requirements (e.g., isolating a CCP and the SIPs per SR 3.4.12.1 and SR 3.4.12.2) does not require special authorization.

1.3.3 Qualitative evaluation based on Key Safety Function degradation should be performed for risk significant equipment removed from service in MODE 4. No quantitative core damage frequency values should be used since the probabilistic risk analysis is based on a full power model.

1.4 Certain risk significant components cannot be taken out of service for on-line maintenance or result in very short Tech Spec action statements. In these cases, risk insights provide limited value. Therefore, this procedure will limit itself to assessing probabilistic and safety function degradation risk on SSCs listed in Attachment 9.1. See also reference 7.7 for bases.

2. DISCUSSION

2.1 Risk from performing maintenance on-line is minimized by:

2.1.1 Performing only those preventative and corrective maintenance items on-line required to maintain the reliability of the structure, system, or component (SSC).

2.1.2 Minimizing cumulative unavailability of safety-related and risk significant SSCs by limiting the number of at-power maintenance outage windows (MOW) per cycle per train/component. Refer to AD7.ID4.

2.1.3 Minimizing the total number of SSCs out-of-service (OOS) at the same time.

2.1.4 Minimizing the risk of initiating plant transients (trips) that could challenge safety systems by implementing compensatory measures.

2.1.5 Avoiding higher risk combinations of OOS SSCs using Probabilistic Risk Assessment (PRA) insights.

2.1.6 Maintaining "defense in depth" by avoiding combinations of OOS SSCs that are related to similar safety functions or that affect multiple safety functions.

2.2 Scheduling the SSCs in the 12 week rolling matrix according to their Train/Bus/Set relationship minimizes a large part of the Tech Spec conflict and risk factor. Refer also to AD7.ID4.

2.3 Risk is managed as follows:

2.3.1 Plant trip risk activities or conditions are evaluated qualitatively and mitigated by:

a. Taking appropriate compensatory measures; and/or

b. Ensuring defense-in-depth for safety systems that are challenged by a plant trip.

2.3.2 Risk significant equipment OOS configurations (singles and pairs of components) affecting Core Damage Frequency (CDF) have been quantitatively pre-analyzed by probabilistic risk methods.

2.3.3 The ability of SSCs to support Key Safety Functions (KSFs) that protect the fission product barriers (clad, RCS, and containment) is evaluated qualitatively.

2.3.4 Compensatory measures and management authorization may be required to allow higher risk configurations for planned maintenance. Management notification may be required for emergent higher risk situations.

3. RESPONSIBILITIES

3.1 The engineering director is responsible for overall administration of the Maintenance Rule per MA1.ID17.

3.2 The scheduling supervisor is responsible for overall coordination of scheduling on-line maintenance in accordance with this instruction and AD7.ID4.

3.3 The cognizant manager is responsible for identifying and proposing compensatory measures for HIGH or VERY HIGH risk activities performed by their groups per MA1.DC10 and MA1.DC11.

3.4 The operations manager is responsible for approving higher risk OOS configurations as identified by this instruction.

3.5 The operations work control supervisor and the daily scheduling supervisor are responsible for overall implementation of the on-line risk management program.

3.6 The operations work week manager (or, in his absence, an OPS Shift Manager) is responsible for ensuring risk assessments for planned maintenance are completed in accordance with this instruction and AD7.ID4.

3.7 The operations shift foreman is responsible for:

- Verifying risk assessments for planned activities are valid; and for
- Performing risk assessments for emergent conditions affecting the plant in accordance with this instruction and AD7.ID4.

3.8 The PRA supervisor is responsible for:

- Providing the risk insights and numerical risk values for this procedure; and for
- Maintaining the ORAM-Sentinel software.

4. DEFINITIONS

4.1 **Compensatory Measures** - Actions taken to mitigate the risk from planned or emergent plant equipment conditions or external or internal conditions. Examples include:

NOTE: Deferral of elective work to avoid unacceptable risk is an assumed option.

4.1.1 Risk Awareness

- Tailboards, PA announcements, Plan of the Day, special notices, etc.
- Direct supervisory oversight.
- Upper Management authorization.
- Abnormal or infrequent evolution briefings.

4.1.2 Minimize duration of the activity or condition

- Pre-planning - Tailboards, pre-job walkdowns, pre-staging equipment and supplies, mock-up training.
- Contingency planning - Canned tailboards, JIT simulator training, temporary procedures, call-out lists, back-out criteria, etc. (plan for failure).
- Augmented coverage - Working two (2) shifts/day, around-the-clock coverage.

4.1.3 Mitigate Consequences

- Protect redundant equipment - barricading OPERABLE DEGs during redundant DEG MOWs, offsite power outages, or grid instability; restricting activities in the 500kV and 230kV yards when DEGs are out of service.

4.2 **Core Damage Frequency (CDF)** - The instantaneous risk of a core damaging accident's occurrence expressed as occurrences per year.

4.2.1 The plant specific Probabilistic Risk Analysis (PRA) calculates CDF for various plant configurations and accident scenarios.

a. For example, the CDF for operating the plant with all safety systems available (no maintenance case) is about 1E-5/yr; that is, a core damaging accident might be expected to occur about once every 100,000 years.

b. If startup power were to be removed from service for the whole year, the CDF would increase by about a factor of 10 to about 1E-4/yr, or once every 10,000 years.

4.2.2 Because the PRA model evaluates individual component failures, the CDF for Train Level SSCs in this procedure are sometimes composite values representative of the train vice specific components.

4.3 **Core Damage Probability (CDP)** - The product of the CDF and the out-of-service duration. This represents the actual risk of a core damaging event occurring during a given period of time.

4.3.1 From the above example, if startup power was to be out-of-service for six (6) hours, the core damage probability would be:

$$\frac{(1E-4/yr)\,(6\ hrs)}{8760\ hrs/yr} = 6.9E-8$$

4.4 **Degraded** - SSC condition or performance is below nominal. May still be considered OPERABLE, but operation may be curtailed or under increased monitoring. Examples include:

- SSCs in Maintenance Rule (a)(1) (goal setting) status or approaching performance criteria limits.
- SSCs on the Predictive Maintenance "Equipment Watch List."
- SSCs on alert frequency Surveillance Testing (PX ALRT ARs).
- SSCs requiring compensatory measures per Prompt Operability Assessments or Operability Evaluations (refer to OM7.ID8 and OM7.ID12).
- SSCs with other significant existing deficiencies (CM or AT EQPR or EVAL ARs, operator workarounds, etc.).

4.5 **External Risk** - Trip Risks from factors originating outside the plant boundaries. Severity of trip risk will be evaluated qualitatively on a case-by-case basis. The following examples should be classified as High Trip Risks:

4.5.1 Offsite power system induced trip risks:

<u>NOTE</u>: External risks affecting offsite power may also affect plant trip mitigation SSCs.

- Peak power demand (i.e., CAISO stage 3 or higher grid emergencies).
- Fires threatening offsite power source lines.
- Storms (wind, rain, etc.).

4.5.2 Direct trip risk from storms:

- High ocean swell warning. (Refer to OP O-28, "Intake Management.")
- Lightning strikes, etc.

4.5.3 Seismic risk factors.

- Parkfield Level A earthquake prediction. (Refer to CP M-4, "Earthquake.")
- Tsunami warning. (Refer to CP M-5, "Tsunami Warning.")

4.6 **Internal Risk** - Risks from operations, maintenance, and environment originating inside the plant boundaries.

4.6.1 Examples of environmental effects include fire, flooding, high and medium energy line breaks.

4.6.2 So long as compensatory measures are put in place per the Equipment Control Guideline actions for degraded engineered features, risk to adjacent components is considered insignificant.

4.6.3 Failure to implement ECG actions within the required time limits should require an after the fact risk assessment by the PRA Group. This includes:

- Fire protection - Barriers, doors, detection, suppression, etc. (ECG 18).
- Flooding - Doors, barriers, drains, etc. (ECG 80).
- High and Medium Energy Line Breaks - Doors, blow-out panels, etc. (ECG 80).

4.7 **Key Safety Function (KSF)** - A function required to protect the fission product barriers. Degradation of "defense in depth," the ability to maintain the KSF, is evaluated by the use of logic trees when removing Risk Significant SSCs from service for maintenance. This assessment is independent of the PRA AOT method.

4.7.1 These KSFs correspond to the critical safety functions in the Emergency Operating Procedures (EOP) Function Restoration Guidelines (FRGs) that mitigate extreme - RED, or severe - MAGENTA, challenges to the barriers.

NOTE: The RCS inventory critical safety function in the FRGs was not included because there are no RED or MAGENTA paths in that series of procedures.

4.7.2 Two additional support functions, Component Cooling and Vital Electric Power, were created in addition to those in the FRGs. Many individual components can be affected by a degradation of these support systems. For ease of use, rather than evaluate the affect on each supported component, the new KSFs were created.

4.7.3 Similar to the FRGs, KSF defense in depth degradation is represented by a color.

a.	GREEN	KSF fully satisfied
b.	YELLOW	Moderate degradation
c.	ORANGE	Significant degradation
d.	RED	Severe degradation

4.8 **Large Early Release Frequency (LERF)** - The instantaneous risk to the public from releases via penetration failures three (3) inch diameter and larger before the plant's emergency response plan has been implemented in an accident scenario. The only release pathway this large that could be affected by maintenance is the vacuum/pressure relief or containment purge and exhaust valves.

4.8.1 LERF risk is evaluated qualitatively under the Containment Key Safety Function.

a. For example, venting of containment for pressure relief should be avoided if a Train Level SSC affecting CDF was OOS giving a yellow Core Cooling or Containment Key Safety Function color (e.g., RHRP give yellow for both).

b. Alternatively, the example above would be acceptable if compensatory measures to mitigate the risk were implemented such as increased risk awareness tailboards, contingency planning in the event of a leak, etc.

c. If an inoperable penetration is isolated to comply with Tech Spec 3.6.3 actions, those compensatory measures are sufficient to mitigate the LERF risk. No other risk management actions would be required.

4.9 **Probabilistic Risk Assessment Allowable Outage Time (PRA AOT)** - The number of hours a single or combination of Risk Significant Train Level SSCs may be OOS before the time-integrated risk <u>addition</u> to the "no maintenance case" Core Damage Probability (CDP) exceeds 1E-6. Industry PRA guidelines define a change of less than 1E-6 as "insignificant risk increase." The PRA AOT is used as a "ruler" to compare the relative risk of removing Risk Significant Train Level SSCs from service.

4.10 **Risk Significant** - As defined by MA1.ID17, a SSC is deemed to be risk significant if:

4.10.1 It is a significant contributor to the plant specific PRA;

4.10.2 If it provides or supports a Key Safety Function; or

4.10.3 It has been judged to be risk significant by the Maintenance Rule expert panel.

<u>NOTE</u>: Certain risk significant components cannot be taken out of service for on-line maintenance or result in very short Tech Spec action statements. In these cases, risk insights provide limited value. Therefore, this procedure will limit itself to assessing probabilistic and safety function degradation risk on SSCs listed in Attachment 9.1. See also reference 7.7 for bases.

4.11 **Threshold PRA AOT** - The PRA AOT of the riskiest single Risk Significant Train Level SSC normally allowed to be removed from service for on-line maintenance. It is reasoned that any combination of Risk Significant Train Level SSCs may be removed from service as long as it is allowed by Tech Specs, OP1.DC17, and the combination is no riskier than the riskiest single Risk Significant Train Level SSC.

4.12 **Train Level SSC (TLS)** - Equipment name that represents the train affected by individual component maintenance or failure. For example:

OOS Component	TLSSC
FCV-95	AFWP1
8803A	CCP1
8807B	SIP2
Opposite Unit ASW pp	FCV-601

4.13 **Trip Mitigation SSC** - The primary SSCs that are immediately challenged during a normal plant trip (no safety injection). Loss of redundancy for these SSCs present significant complications in the event of a plant trip:

- Offsite power sources (230kV initially, 500kV with delayed access)
- Emergency Diesel Generators (backup to 230kV startup)
- Auxiliary Feedwater trains
- Auxiliary Saltwater trains

4.14 **Trip Risk** - Any activity that could lead to a reactor or turbine trip. Turbine and reactor trips represent the most likely transient initiators leading to core damaging and large early release events.

4.14.1 HIGH risk activities evaluated per MA1.DC10 or MA1.DC11 are considered Trip Risks by this procedure *only* if they might lead to a transient having a significant effect on reactor power (>2%RTP). See Reference 7.9.

5. PRECAUTIONS AND LIMITATIONS

5.1 The 12 week rolling matrices shown in Attachment 9.2 are FOR INFORMATION ONLY. The Daily Work Coordination Group (DWC) keeps current versions of the matrices for each unit.

5.2 Current PRA AOT values are found using the on-line risk assessment computer program ORAM-Sentinel. PRA AOT values for single configurations are documented on Attachment 9.1.

5.3 The SFATs are based on the equipment importance in accident mitigation as described in the EOP background documents. SFATs are displayed using ORAM-Sentinel software.

6. INSTRUCTIONS

6.1 Developing the 12 Week Rolling Matrix

6.1.1 The 12 Week Rolling Matrix (Matrix) is based on the STPs performed in MODE 1 for all the major risk significant SSCs. (Refer to Attachment 9.1, List of Risk Significant Systems.)

6.1.2 The weeks are categorized by 3 methods.

a. SSPS Train relation - A, B, or A/B

b. Vital bus relation - F, G, H, or Non-bus

c. Protection Set relation - I, II, III, IV

d. Thus, the 4 week sub-cycle within the 12 week cycle is:

1.	Train A/B	Bus H
2.	Train B	Bus G
3.	Train A	Bus F
4.	Train A/B	Non-bus

e. Protection set weeks are spread over the full 12 week cycle.

6.1.3 Each week is further subdivided into two work windows; Tuesday-Wednesday, Thursday-Friday - each 48 hours long.

a. This is consistent with the AD7.ID4 requirement that T.S. SSCs out-of-service (OOS) duration be scheduled not to exceed 1/2 the Tech Spec Action Allowable Outage Time (AOT). For most ESF components, this is 1/2 of 72 hours: 36 hours.

b. This also provides time separation for working two safety related SSCs in the same week.

6.1.4 Compile a listing of the quarterly and monthly STPs for the major SSCs.

6.1.5 Classify the SSCs by SSPS train, vital bus and protection set as described above and spread out the STPs through the 12 week cycle in their appropriate train/bus/set weeks (refer to Attachment 9.2, Sample 12 Week Rolling Matrix).

a. Group the STPs at the train level if possible, for example slave relay test with pump test and associated valve tests.

b. Levelize for daily work loading, cross-discipline support required for test performance, opposite unit testing schedule, test instrumentation requirements. etc.

6.1.6 Analyze weeks for possible trip risks, train level probabilistic risk, and safety function degradation conflicts as described below and correct as required.

6.1.7 Revisions to the matrix should be minimized.

a. If changes are found to be necessary, follow above guidance and analyze for risk similarly.

b. STP performance should be short cycled as required to avoid use of surveillance interval grace period during transition to the revised matrix. (Refer to AD13.DC1.)

6.1.8 The Matrix Coordinator should mark up a long-term matrix spreadsheet (example: Attachment 9.3) or schedule with planned MOWs from the PIMS PM RTS due dates and other Daily Work Coordination (DWC) reports.

a. Identify all MOWs on the spreadsheet to help visualize the SSCs OOS at the same time for risk assessment and workload levelization.

b. Verify Risk Significant SSC MOWs are correctly scheduled in their train/bus/set week to align with the component STP. Correct the PIMS/P3 schedule if necessary or obtain Work Week Manager (WWM) approval for deviation.

c. Schedule so that the STP provides the PMT for the maintenance on the SSC.

6.2 Managing Risk in the Maintenance Planning Phase

6.2.1 The OPS work week managers shall ensure risk management actions are completed for planned work considering:

a. Expected plant conditions during the week.

b. Expected external conditions due to seasonal effects (e.g., storm or fire season, summer peak loads, etc.).

6.2.2 Determine the activities scheduled for the week that are Trip Risks.

6.2.3 Determine the Risk Significant SSCs that are scheduled to be OOS. Classify them at the train level (TLS). Refer to Attachment 9.1.

a. For each TLS, determine its current unavailability and health of its redundant train.

1. The cognizant system engineer and/or maintenance manager should give concurrence to schedule or consider deferral of maintenance.

a) If the TLS is approaching or will exceed 75% of its Maintenance Rule Availability Performance Criteria; or

b) If the TLS's redundant train is Degraded.

6.2.4 If a Trip Risk is scheduled concurrently with OOS or degraded trip mitigation TLSs, attempt to separate the activities.

6.2.5 If two or more TLSs are scheduled to be OOS in the same week, attempt to separate the work to avoid overlap.

6.2.6 Determine the risk configurations during the week (unique plant states where one or a combination of trip risks or TLSs will be OOS).

6.2.7 Manage the trip risk, probabilistic risk, and/or safety function degradation associated with each configuration as described in Steps 6.4, 6.5 and 6.6.

6.2.8 Propose risk mitigation compensatory measures, as appropriate.

6.2.9 Document risk management actions for each configuration on a TS sheet per OP1.DC17.

6.3 Managing Risk in the Maintenance Execution Phase (Real Time)

6.3.1 The SFM shall evaluate and manage the risk of all activities or conditions based on the current plant state:

a. Before any planned OR emergent maintenance is to be performed.

b. As soon as possible when an emergent plant condition is discovered.

c. As soon as possible when an external or internal event or condition is recognized.

6.3.2 Verify if the activity or condition is a Trip Risk and manage per step 6.4.

6.3.3 Determine if the activity removes a TLS from service, and

a. Manage probabilistic risk per step 6.5.

b. Manage safety function degradation per step 6.6.

6.3.4 If the redundant train remaining in service is degraded, implement additional compensatory measures.

6.3.5 If the evaluation reveals unacceptable risk, determine course of action based on restoration of safety function first, PRA aspects second.

6.3.6 Document risk management actions for each configuration on a TS sheet per OP1.DC17.

6.4 Plant Trip Risk Assessment

6.4.1 For <u>pre-planned</u> trip risk activities:

a. Ensure the work group proposing Trip Risk activities completes the appropriate authorization form from MA1.DC10 or MA1.DC11.

b. Concur with or propose compensatory measures to mitigate the trip risk, as appropriate.

c. Check for concurrent OOS or degraded plant trip mitigation TLSs using ORAM-Sentinel or TS Sheet review (offsite power, DEGs, AFW, or ASW). If present:

1. Obtain OPS manager authorization for concurrent performance.

2. Implement additional compensatory actions, as appropriate

3. Document condition and basis for approval on the appropriate TS Sheet.

6.4.2 For emergent plant trip risk activities or conditions:

NOTE: Emergent External Conditions should be treated as Trip Risks.

a. Implement immediate compensatory measures, as appropriate.

b. Check for concurrent OOS or degraded plant trip mitigation TLSs using ORAM-Sentinel or TS Sheet review. If present:

1. Implement additional compensatory measures to mitigate risk, as appropriate.

2. Notify the operations manager.

3. Document condition in an Action Request.

6.5 Probabilistic Risk Assessment

NOTE: If the OOS TLS is a Trip Mitigation TLS, also check for concurrent Trip Risk using ORAM-Sentinel or TS sheet review and evaluate per step 6.4.

6.5.1 Determine the PRA AOT for the single or combination of TLSs OOS by using ORAM-Sentinel. If ORAM-Sentinel is not available, determine PRA AOT as follows:

a. Use Attachment 9.1 to obtain PRA AOT values for a single TLS OOS.

b. Contact the PRA group for any multiple TLSs OOS.

6.5.2 If the scheduled duration of work is less than the PRA AOT, determine and implement appropriate compensatory measures.

6.5.3 If the PRA AOT is less than the threshold PRA AOT:

a. Verify operations manager approval (or notification for emergent conditions) regardless of the scheduled duration. Scheduled duration is a factor that will be of importance in the decision process.

b. Basis for approval should be documented.

c. Determine and implement additional compensatory measures, as appropriate

d. Document the higher risk configuration in on the TS sheet.

6.5.4 If the scheduled duration of work is greater than the PRA AOT, then:

NOTE: If the duration of work exceeds the PRA AOT then, by definition, the risk increase is no longer insignificant.

a. Verify operations manager approval (or notification for emergent conditions).

b. Document basis for approval.

c. Determine and implement additional compensatory measures, as appropriate.

d. Document the higher risk configuration in an action request.

6.6 Safety Function Degradation Assessment - For each configuration determined above, assess and manage the degradation of Key Safety Functions.

6.6.1 Determine the Key Safety Functions that are affected by the OOS TLS(s) by using the PC program ORAM-Sentinel. If ORAM-Sentinel is not available, use Attachment 9.1 to determine KSF score for a single SSC TLS, or contact the PRA group.

6.6.2 Determine the degree of degradation (color) of each affected Key Safety Function by selecting the affected TLS in ORAM-Sentinel.

6.6.3 If any TLS OOS combination results in a RED terminus.

a. The condition is not normally allowed and may be a Tech Spec violation.

b. Prior PSRC approval (operations manager notification for emergent conditions) is required.

c. Document the RED KSF configuration in an Action Request.

6.6.4 If any TLS OOS combination results in an ORANGE terminus:

a. Verify operations manager approval (or notification for emergent conditions).

b. Document basis for approval.

c. Determine and implement additional compensatory measures, as appropriate.

d. Document emergent ORANGE configuration in an Action Request.

6.6.5 If an OOS TLS or combination results in one or more YELLOW terminuses, evaluate as follows:

a. The Key Safety Functions yellow terminuses are assigned weighting factors in accordance with their importance IAW EOP FR F-0:

1.	Subcriticality	=5
2.	Core Cooling	=4
3.	Heat Sink	=3
4.	RCS Integrity	=2
5.	Containment	=1
6.	Vital Power	=5
7.	Component Clg	=5

b. If the sum of the weighting factors for the YELLOW terminuses is 8 or greater, then:

1. Verify operations manager approval (or notification for emergent conditions).
2. Document basis for approval.
3. Determine and implement additional compensatory measures, as appropriate.
4. Document emergent configurations with KSF ≥ 8 in an Action Request.

c. If the sum of the weighting factors for the YELLOW terminuses is less than 8, determine and implement compensatory measures, as appropriate.

7. REFERENCES

7.1 10 CFR 50.65 "The Maintenance Rule."

7.2 ERIN Engineering, "Equipment Out -of -Service Monitoring for the Maintenance Rule at Diablo Canyon - Technical Basis Document," dated 10/95.

7.3 NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," dated 7/2000.

7.4 NRC Inspection Manual, Inspection Procedure 62706, "Maintenance Rule," dated 8/31/95.

7.5 AD7.ID4, "On-Line Maintenance Scheduling."

7.6 OP1.DC17, "Control of Plant Equipment Required by the Technical Specifications or Other Designate Programs."

7.7 Procedure History Sheet for AD7.DC6 Rev 1, "Bases For Attachment 9.1, "Risk Significant Train Level SSCs."

7.8 PG&E PRA Calculation File C13, Revision 1, "PRA Evaluation of Various Maintenance Configuration to Support the On-Line Maintenance Risk Assessment Procedure (AD7.DC6)," 08/31/01.

7.9 Action Request A0551882, "AD7.DC6, RISK MANAGEMENT VS. MA1.DC11, WORK RISK ASSESSMENT".

8. RECORDS

None

9. ATTACHMENTS

9.1 "Risk Significant Train Level SSCs," 11/08/01

9.2 "Sample 12 Week Rolling Matrix," 05/23/96

9.3 "Sample MOW Planning Spreadsheet," 05/23/96

9.4 "On-Line Risk Management Summary," 11/08/01

10. SPONSOR

A.J. Chitwood

DIABLO CANYON POWER PLANT
AD7.DC6
ATTACHMENT 9.1

TITLE: Risk Significant Train Level SSCs

Sys	Trn	Bus	Train Level SSC (See Notes)	Risk Signif-icant	PC1	SFAT	PRA	PRA AOT	Sub critical-ity	Core Cool-ing	Heat Sink	RCS Integ-rity	Ctmt	Vital Power	Comp Cool-ing	SF Score	Train Level SSC (See Notes)
3	A/B	Non	AFWP 1	y	y	y	y	993			3					3	AFWP 1
3	B	H	AFWP 2	y	y	y	y	3432			3					3	AFWP 2
3	A	F	AFWP 3	y	y	y	y	2559			3					3	AFWP 3
7			PCV-455C	y	y	y	y	>8760			3	2				5	PCV-455C
7			PCV-456	y	y	y	y	>8760			3	2				5	PCV-456
8	A	F	CCP 1	y	y	y	y	2770	5	4	3	2				14	CCP 1
8	B	G	CCP 2	y	y	y	y	2459	5	4	3	2				14	CCP 2
9	A	F	SIP 1	y	y	y	y	>8760		4	3					7	SIP 1
9	B	H	SIP 2	y	y	y	y	8656		4	3					7	SIP 2
10	B	G	RHRP 1	y	y	y	y	4704		4			1			5	RHRP 1
10	A	H	RHRP 2	y	y	y	y	4755		4			1			5	RHRP 2
12	B	G	CSP 1	y	y	y	y	>8760					1			1	CSP 1
12	A	H	CSP 2	y	y	y	y	>8760					1			1	CSP 2
14			CCWHE1	y	y	y	y	336							5	5	CCWHE 1
14			CCWHE2	y	y	y	y	370							5	5	CCWHE 2
14	A	F	CCWP 1	y	y	y	y	1144							5	5	CCWP 1
14	B	G	CCWP 2	y	y	y	y	1609							5	5	CCWP 2
14	A/B	H	CCWP 3	y	y	y	y	689							5	5	CCWP 3
17	A	F	ASP 1	y	y	y	y	336							5	5	ASP 1
17	B	G	ASP 2	y	y	y	y	370							5	5	ASP 2
17			FCV-601	y	y	y	y	502							5	5	FCV-601
21	A/B	H	DEG 1 (2)	y	y	y	y	823						5		5	DEG 1
21	B	G	DEG 2 (1)	y	y	y	y	457						5		5	DEG 2
21	A	F	DEG 3	y	y	y	y	408						5		5	DEG 3
21		H*	DFOTP1	y	y	y	y	1150						5		5	DFOTP1
21		G*	DFOTP2	y	y	y	y	1023						5		5	DFOTP2
23			CFCU X	n	n	y	y	>8760					1			1	CFCU X
23			CRVS S-35	y	y	n	y	>8760								0	CRVS S-35
23			CRVS S-36	y	y	n	y	>8760								0	CRVS S-36
38	A		SSPS A	y	y	y	y	759	Orange							NA	SSPS A
38	B		SSPS B	y	y	y	y	728	Orange							NA	SSPS B
67		F	BTC 1	y	y	y	y	5000						5		5	BTC 1
67		G	BTC 2	y	y	y	y	1398						5		5	BTC 2
67		H	BTC 32	y	y	y	y	1541						5		5	BTC 32
69			S/U Pwr	y	y	y	y	119						5		5	S/U Pwr
70			500kV OSP	n	n	y	y	990						5		5	500kV OSP

RS – Risk significant per Maintenance Rule AND can be worked On Line
PC1 – Unavailability hours tracked as performance criteria
SFAT – Included in Safety Function logic trees
PRA – Modeled in PRA AOT spreadsheet
PRA AOT – Single component AOT to 1E-6 additional CDF

NOTES: Only those Risk Significant SSC's that are modeled in the DCPP PRA, have PC1 availability AOT's assigned, AND can be removed from service for maintenance on-line are included in this table. Examples of Risk Significant SSC's not in the table include RCS, Pzr safeties, MSIV's, S/G's, RWST, CST, etc. See reference 7.7 for bases.

DIABLO CANYON POWER PLANT
AD7.DC6
ATTACHMENT 9.2

TITLE: Sample 12 Week Rolling Matrix

UNIT ONE TWELVE WEEK ROLLING MATRIX

	MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
WEEK 1 TRAIN A/B BUS H	DAYSHIFT: M-67A FIRE VALVES		M-9A DG11	P-13B FIRE PP 02	DAYSHIFT: OP C-1 SEC. PLANT M-69C F IRE EXT	P-AFW-12 V-3P6 LC V110-113	M-51 ALL CFCUs P-12B1 DFO PP 01 DAYSHIFT: P-24 LTCW PP 01
WEEK 2 TRAIN B BUS G	V-3H12 RCV16 DAYSHIFT: M-67A FIRE VALVES V-3H11 LCV69 & 70	M-26 CCW HX 12	P-CCP-12	M-16BB *M-9A DG 12 *V-3E11 8803A&B DAYSHIFT: CNTNMT ENTRY *SEAL TABLE INSP.	M-16HB *P-CSP-11 *V-3I3 9001A DAYSHIFT: SP S-312S SEC DG M-69B CO 2	P-MUW-02	P-12B2 DFO PP 02 DAYSHIFT: P-24 LTCW PP 02
WEEK 3 TRAIN A BUS F	DAYSHIFT: V-3R1 10% DUMPS M-67A F IRE VALVES	M-9A DG 13	M-54 SEAL FLOW DAYS HIFT: M-89 ECCS VENTING	P-SIP-11 V-3L10 8923A&B V-3L2 8821A&B V-3L3 8807A&B M-26 CCW HX 11	P-13B FIRE PP 01 DAYSHIFT: m-69A FIRE EXT	P-AFW-13	P-CCW-11 M-16K *V-3S4 *V-3S3 DAYSHIFT: P-24 LTCW PP 03
WEEK 4 TRAIN A/B BUS NON	M-21A DAYSHIFT: M-67A FIRE VALVES	P-SIP-12 DAYSHIFT: R-1A RODS	M-16J BLDN VLVS M-16N BLDN/AFW *V-3S2 BLDN OC *P-AFW-11 *V-3P5 LCV 106-109 *V-3R5 FCV 95 * V-3R6 FCV-37&38	M-16P2 PAINT/WELD RESTRICTION S FOR WEEKEND TESTING DAYSHIFT: CNTNMT ENTRY * STP I-1D	DAYSHIFT: M-67C HOSE REELS M-10A DFOST	M-4 ABVS M-5 FHBVS M-6A CRVS	
WEEK 5 TRAIN A/B BUS H	DAYSHIFT: M-67A FIRE VALVES	M-9A DG 11		P-13B FIRE PP 02	DAYSHIFT: OP C-1 SEC. PLANT M-69C FIRE EXT M-16HA *P-CSP-12 *V-3I3 9001B	P-AFW-12	M-51 ALL CFCUS DAYSHIFT: P-24 LTCW PP 01
WEEK 6 TRAIN B BUS G	V-3K5 8146,8147 V-3K6 8166,8167 DAYSHIFT: M-67A FIRE VALVES	P-7B ASW PP 12 M-26 CCW HX 12	PAINT/WELD RESTRICTI ONS FOR M-16D	M-9A DG 12 V-3S8 FCV361 V-3J1 BLOCK VLVS DAYSHIFT: CNTMNT ENTRY *SEAL TAB LE INSP.	M-16O *P-RHR-11 DAYSHIFT: SP S-312S SEC DG M-69B CO 2	P-CCW-12	P-BAT-12 M-16I *V-3S1 PH. A VLVS *V-3S7 PH. A VLVS *V-3S8 PH. A VLVS DAYSHIFT: P-24 LTCW PP 02
WEEK 7 TRAIN A BUS F	V-3P4 AFW VLVS DAYSHIFT: M-67A FIRE VALVES	V-3G1 GDTs M-9A DG 13	M-54 SEAL FLOW P-CCP-11 DAYSHIFT: M-89 ECCS VENTING	M-26 CCW HX 11 P-7B ASW PP11 V-3F1 FCV 495 V-3F2 FCV 496 V-3F3 FCV 601 V-3F4 FCV 602 V-3F5 FCV 603	P-13B FIRE PP 01 DAYSHIFT: m-69A FIRE EXT	M-16E *P-AFW-13	DAYSHIFT: P-24 LTCW PP 03
WEEK 8 TRAIN A/B BUS NON	M-21A DAYSHIFT: M-67A FIRE VALVES	M-16P4 V-303 DFO VLVS DAYSHIFT: R-1A RODS	P-AFW-11	PAINT/WELD RESTRICTIONS FOR TESTIN G DAYSHIFT: CNTMNT ENTRY *STP I-1D	DAYSHIFT: M-10A DFOST M-67C HOSE REELS	M-4 ABVS M-5 FHBVS M-6A CRVS	DAYSHIFT: P-12B3 PORT. DFO PP 01
WEEK 9 TRAIN A/B BUS H	PAINT/WELD RESTRICTIONS FOR TESTING FOR STP M-16 U DAYSHIFT: M-67A FIRE VALVES		M-16A *M-9A DG11 *V-3E9 8801A&B M-16U *V-3S5 PH. A VLVS PAINT/WELD RESTRICTI ONS FOR M-16C	P-13B FIRE PP 02	M-16C *P-RHR-12 DAYSHIFT: OP C-1 SEC PLANT M-69C FIRE EXT	M-16F *P-AFW-12	M-51 ALL CFCUs DAYSHIFT: P-24 LTCW PP 01
WEEK 10 TRAI N B BUS G	DAYSHIFT: M-67A FIRE VALVES	M-26 CCW HX 12	STP P-MUW-01 *V-3U1 WTR VLVS *V-3U2 WTR VLVS	M-9A DG 12 DAYSHIFT: CNTMNT ENTRY *SEAL TAB LE INSP.	M-16M *V-3T1 CVI VLVS P-SFP-12 DAYSHIFT: SP S-312S SEC DG M-69B CO 2	P-17B CP 13	V-3E1 FCV 110A V-3E2 FCV 110B V-3E5 8104,8445 V-3E6 FCV 128 DAYSHIFT: P-24 LTCW PP 02
WEEK 11 TRAI N A BUS F	DAYSHIFT: M-67A FIRE VALVES	M-16BA *M-9A DG 13	M-54 SEAL FLOW DAYSHIFT: M-89 ECCS VENTING	M-26 CCW HX 11	M-16o DUMP INTRLK P-13B FIRE PP 01 DAYSHIFT: m-69A FIRE EXT	P-AFW-13	P-BAT-11 DAYSHIFT: P-24 LTCW PP 03
WEEK 12 TRAI N A/B BUS NO N	M-21A DAYSHIFT: M-67A FIRE VALVES	DAYSHIFT: R-1A RODS	P-AFW-11	V-3H7&8 CCW VLVS V-3M1,2,4 RHR VLVS PAINT/WELD RESTRICTION S DAYSHIFT: CNTMNT ENTRY *STP I-1D	P-SFP-11 M-16P3 *V-3R3 BLDN IC *V-3R4 MSIV BYP DAYSHIFT: M-10A DFOST M-67C HOSE REELS	M-4 ABVS M-5 FHBVS M-6A CRVS	P-CCW-13 P-12B4 PORT DFO PP 02

DIABLO CANYON POWER PLANT
AD7.DC6
ATTACHMENT 9.3

TITLE: Sample MOW Planning Spreadsheet

Date	10/29/95	11/5/95	11/12/95	11/19/95	11/26/95	12/3/95	12/10/95	12/17/95	12/24/95	12/31/95	1/7/96	1/14/96
Events	1R7 11/1			Thksgvg					Chrstms	New Yrs		
DWC Week	9544	9545	9546	9547	9548	9549	9550	9551	9552	9601	9602	9603
12WMtxWk	1	2	3	4	5	6	7	8	9	10	11	12
Train	A/B	B	A	A/B	A/B	B	A	A/B	A/B	B	A	A/B
Bus	H	G	F	Non	H	G	F	Non	H	G	F	Non
System												
00				I-1D				I-1D				I-1D
02												
03A							AFWP3					
03B	AFWP2											
03A/B				AFWP1				AFWP1				AFWP1
04												
07			M-54	R-1A			M-54	R-1A			M-54	R-1A
08										PDP3		
08A							CCP1				BATP1	
08B		CCP2				BATP2						
09			M89				M-89				M-89	
09A			SIP1									
09B				SIP2								
10A									RHRP2			
10B						RHR1						
11												
12A					CSP2							
12B		CSP1										
13										SFP2		SFP1
14A			CCWP1									
14B						CCWP2						
14A/B												CCWP3
14HEA			CCWHE1				CCWHE1				CCWHE1	
14HEB		CCWHE2				CCWHE2				CCWHE2		
15												
16		MUWTP2								MUWTP1		
16	LTCWP1	LTCWP2	LTCWP3		LTCWP1	LTCWP2	LTCWP3		LTCWP1	LTCWP2	LTCWP3	
17												
17A							ASP1					
17B		CCWHX2				ASP2						
18	FP2		FP1		FP2		FP1		FP2		FP1	
19												
20				M-21A				M-21A				M-21A
21	DFOTP1	DFOTP2			SAC1B			PDFOP1				PDFOP2
21A			DEG3				DEG3				DEG3	
21B		DEG2				DEG2				DEG2		
21A/B	DEG1				DEG1				DEG1			
22												
23	CFCS				CFCS				CFCS			
23												
23ABV				M-4				M-4				M-4
23FHB				M-5				M-5				M-5
23CRV				M-6A				M-6A				M-6A
24												
25												
26												
27			OWS1									
28												
45		CTMT		CTMT		CTMT		CTMT		CTMT		CTMT
66		SECDEG				SECDEG				SECDEG		
67												

DIABLO CANYON POWER PLANT
AD7.DC6
ATTACHMENT 9.4

TITLE: On-Line Risk Management Summary

Evaluate risk for all planned or emergent activities, equipment OOS, or external conditions as follows:

NOTE 1: For all steps below, deferring elective activities to avoid unacceptable risk is an assumed option.

NOTE 2: If all steps are answered "NO," risk evaluation documentation is not required.

Step 1. Is the activity or condition a Trip Risk?		
YES		• Emergent Trip Risk - implement compensatory measures;
		• Planned Trip Risk - concur with comp measures per MA1.DC10 or 11;
		• AND GO TO Step 2.
NO		GO TO Step 3

Step 2. Is there a Trip Risk concurrent with degraded or out of service Trip Mitigation SSCs?		
YES		• Verify OPS manager concurrence or notification to allow 1 and 2 concurrently;
		• AND implement compensatory measures;
		• AND GO TO Step 3.
NO		GO TO Step 3
N/A		GO TO Step 3

Step 3. Is the SSC out of service Risk Significant for CDF or LERF?		
YES		• Evaluate PRA and KSF;
		• Implement compensatory measures;
		• If the OOS SSC is a Trip Mitigation SSC, THEN verify Step 2 is complete;
		• AND GO TO Step 4.
NO		GO TO Step 4

Step 4. Is the remaining in-service redundant train Degraded?		
YES		Implement additional compensatory measures.
NO		Risk evaluation complete.

This checklist may be summarized as a lamicoid at the SFM desk for reference.