California ISO

Grid Planning Standards

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Draft Revision 1

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I. Introduction

The purpose of this document is to specify the Planning Standards that will be used in the planning of California Independent System Operator (CAISO) controlled grid transmission facilities. The primary principle guiding the development of CAISO Grid Planning Standards is to develop consistent reliability standards for the CAISO grid that will maintain or improve the level of transmission system reliability that existed with the pre-CAISO planning standards. The previous version of this document was last revised on February 7, 2002 and therefore they have been reviewed in their entirety and revised accordingly through work groups within a CAISO Stakeholder Group activity. Establishment of these CAISO Grid Planning Standards has been accomplished consistent with the CAISO Tariff as follows:

The ISO Tariff specifies:

7.2.2.1 The ISO shall exercise Operational Control over the ISO Controlled Grid to meet planning and Operating Reserve criteria no less stringent than those established by WECC and NERC as those standards may be modified from time to time, and Local Reliability Criteria that are in existence on the ISO Operations Date and have been submitted to the ISO by each Participating TO pursuant to Section 2.2.1(v) of the TCA. All Market Participants and the ISO shall comply with the ISO Reliability Criteria, standards, and procedures.

7.2.2.2 The ISO Governing Board may establish planning guidelines more stringent than those established by NERC and WECC as needed for the secure and reliable operation of the ISO Controlled Grid. The ISO may revise the Local Reliability Criteria subject to and in accordance with section 5 of the TCA.

7.2.2.3 The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria.

7.2.2.3.1 Applicable Reliability Criteria are defined as the standards established by NERC, WECC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

These ISO Grid Planning Standards fill the role of the “consistent set of reliability criteria” in the above tariff language. To facilitate the development of these Standards, the ISO formed the ISO Grid Planning Standards Committee, which established standards last revised on February 7, 2002. The CAISO’s FERC Ruling 890 filing in December 2007 re-established this committee to perform an annual review and revisions as necessary of CAISO Grid Planning Standards. A new stakeholder activity was initiated with an initial meeting on September 17, 2007 to review the CAISO Grid Planning Standards and recommend changes as necessary. The approach taken is to utilize regional (Western Electricity Coordinating Council – WECC) and national (North American Electric Reliability Corporation - NERC) Planning Standards to the maximum extent possible.
These CAISO Grid Planning Standards build off of, rather than duplicate, standards that have been developed by NERC and WECC. During 2007, compliance with NERC Standards became mandatory with compliance enforced through the Federal Energy Regulatory

Commission (FERC) and WECC. It is also recognized that NERC Standards are continuing to be revised and therefore the CAISO Standards will be revisited on an annual basis to assess conformance with NERC Standards. The CAISO Stakeholder Group has determined that the CAISO Grid Planning Standards should:

- Address specifics not covered in the NERC and WECC Planning Standards.
- Provide interpretations of the NERC and WECC Planning Standards specific to the CAISO Grid.
- Identify whether specific criteria should be adopted that are more stringent than the NERC and WSCC Planning Standards.

The following Section details the CAISO Grid Planning Standards. Guidelines have also been included, such as related to the use of Special Protection Systems for new generation projects. This document also includes interpretations of the terms used by NERC and background information behind the development of these standards and references (web links) to subjects associated with reliable transmission planning and operation.

II. ISO Grid Planning Standards

The ISO Grid Planning Standards include the following:

1. **NERC and WSCC Planning Standards -** The standards specified in the NERC and WSCC Planning Standards unless NERC or WECC formally grants an exemption or deference to the ISO. Their standards are located at: http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=viewdownload&cid=33&POSTNUKESID=0531ba91359ddfe32e9fae86fa474fb1 and https://standards.nerc.net respectively.

2. **Specific Nuclear Unit Standards -** The criteria pertaining to the Diablo Canyon and San Onofre Nuclear Power Plants, as specified in Appendix E of the Transmission Control Agreement located on the CAISO web site at: http://www.caiso.com/docs/09003a6080/25/a3/09003a608025a385.pdf

3. **Combined Line and Generator Outage Standard -** A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies (TPL002 in Section VIII). Supporting information is located within Section V of this document.

4. **New Transmission versus Involuntary Load Interruption Standard**

   A. Involuntary load interruptions are not an acceptable consequence in planning for ISO Planning Standard Category B disturbances (either single contingencies or the combined contingency of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly not cost effective (after considering all the costs and benefits). In any case, planned load interruptions for Category B disturbances are to be limited to radial and local network customers as specified in the NERC Planning Standards.

B. Involuntary load interruptions are an acceptable consequence in planning for Category C and D disturbances (multiple contingencies with the exception of the combined outage of a single generator and a single transmission line), unless the ISO Board decides that the capital project alternative is clearly cost effective (after considering all the costs and benefits).

C. In cases where the application of Standards 4A and 4B would result in the elimination of a project or relaxation of standards that would have been built under past planning practices, these cases will be presented to the ISO Board for a determination as to whether or not the projects should be constructed.

5. **San Francisco Greater Bay Area Generation Outage Standard (In the process of being revised) -** Before conducting Grid Planning studies for the San Francisco Greater Bay Area, the following three units should be removed from service in the base case:

- One 50 MW CT in the Greater Bay Area but not on the San Francisco Peninsula
- The largest single unit on the San Francisco Peninsula
- One 50 MW CT on the San Francisco Peninsula

The case with the above three units out of service should be treated as the “system normal” or starting base case (NERC Category A) when planning the system. Traditional contingency analysis, based on the standards specified in the NERC and WECC (including voltage stability), and ISO standards (such as single line outage overlapping with a single generator outage etc), would be conducted on top of this base condition. The one exception is that when screening for the most critical single generation outage, only units that are not on the San Francisco peninsula should be considered. Similarly, when examining multiple unit outages, at least one of the units considered should not be on the San Francisco Peninsula.

This standard is intended to apply to system planning studies and not system operating studies. In addition, this standard does not apply for determining Reliability Must-Run or Locational Capacity generation requirements.

It is recognized that it may require several years to add the facilities to the system that are necessary to allow the system to meet this standard. The amount of time required will depend on the specific facility additions this standard generates.

Grid Planning Generation Assumptions February 14, 2008

III. Generation Assumptions for Grid Planning Studies

The transmission facilities that planning studies identify as being required in a specific area of the system are determined based on technical studies that make assumptions concerning the availability of planned generation additions. The location and size of these generation additions can dramatically alter the resulting transmission plans. The California Independent System Operator (CAISO) Planning Standards Committee was tasked with developing a standard approach to modeling this new generation in the base cases used to plan the transmission system. The approach needs to allow for the consistent development of base cases and account for the uncertainty associated with future generation development plans. Guidance on the modeling of generation in planning studies is divided into the following sections:

Section A – CAISO Approach to the Modeling of New Generation in Power Flow Cases

Section B - Generation Modeling Information

Section C - Potential Retirement of Old Thermal Generation Including Those That Utilize Once-Thru Cooling Systems

Section A
CAISO Approach on the Modeling of New Generation in Power Flow Cases

[The CAISO's Generation Interconnection Process Reform (GIPR) Initiative will lead to major changes in the way new generation is modeled in power flow cases. This initiative is scheduled to result in the filing of a new Generation Interconnection Process and associated tariff language in early June that will specify which new generation should be modeled in the base cases that are used to determine the transmission plans that the CAISO approves for construction. (At this time, the GIPR proposal is for only the new generation that complete the new study process, execute generator interconnection agreements and provide the required financial security to be modeled in planning the transmission facilities to be approved for construction.) Once FERC approves the new generation interconnection process and tariff changes, hopefully by August, the Grid Planning Standards Committee will need to revise Section A to conform to the approved process.

Although the GIPR Initiative is expected to provide certainty in what generation should be modeled in near-term base cases, it will not address which new generation to model in the longer-term base cases that are used for advance planning studies (rather than for developing the transmission plans to be approved in the annual planning cycle). The members of Group 2 of the present standards drafting effort recognize that Section A also may need some revisions regarding which generation to model in longer-term base cases, but there is no consensus yet on what changes to recommend. Some of the issues that have been discussed include:

- *Whether to add a Level 6 for Load Serving Entities' (LSE) CPUC Approved Long Term Resource Procurement Plans;*
- *Whether prospective generation from Levels 3-6 should be added inside or outside the area of interest;*
- *Whether an objective of adding generation from Levels 3-6 should be minimization of necessary transmission reinforcements;*

- *The extent to which seasonal loads should be considered; and*
- *What should be assumed for the level of imports and exports.*

These issues should be addressed by the Grid Planning Standards Committee along with the changes to Section A that will be needed for the GIPR Initiative.]

For the purposes of developing these assumptions, the following stages of generation development are used:

Level 1: Under construction
Level 2: Regulatory approval received
Level 3: Application under review
Level 4: Starting application process
Level 5: Press release only

After discussing this subject at several meetings, the Committee has developed the following approach toward the modeling of new generation in the initial power flow cases used to assess the need for transmission system additions:

> **1) Up to 1 year Cases:** In these cases, only generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study should be modeled in the initial power flow case.
>
> **2) 2 - 5 year Cases:** In these cases, only generation that is under construction (Level 1) or has received regulatory approval (Level 2) or a Power Purchase Agreement (PPA), and has its commercial operation date in this timeframe, should be modeled in the initial power flow case
>
> **3) 6 - 10 year Cases:** In these cases, only generation that is under construction or has received regulatory approval (Levels 1 and 2) or a PPA should be modeled in the area of interest of the initial power flow case. If additional generation is required to achieve an acceptable initial power flow case, then generation consistent with the LSE's approved Long Term Procurement Plans can be used. In addition, generation from Levels 3, 4, and 5 can be used but only if they are outside of the area of study so that their impact on the facility addition requirements will be minimized.

The modeling assumptions in (2) and (3) above should normally be used to develop the initial power flow cases. However, the individual study groups will retain the flexibility to vary from the above. In addition, the initial power flow case should only be considered as a starting point and not as the definitive case for determining the required transmission upgrades. Sensitivity cases should be examined to explore the impact that changes in generation development plans will have on transmission facility requirements. Using the information from the various cases, a transmission expansion plan should be developed that reasonably accounts for uncertainty in generation development plans.

Note: This policy is applicable given the current Large Generator Interconnection Process currently utilized through the California Independent System Operator as outlined on the CAISO web site at http://www.caiso.com/docs/2002/06/11/2002061110300427214.html. This process is currently under review through a CAISO stakeholder activity and when revised, the CAISO's approach on modeling new generation will be revised as appropriate.

Section B
Generation Modeling Information

A power plant database is located on the California Energy Commission web site at http://www.energy.ca.gov/database/index.html#powerplants. This database lists all power plants in California one-tenth (0.1) megawatt or larger by name, county where located, owner, operator, present status and other information.

The CEC's web site at http://www.energy.ca.gov/ also contains valuable information on proposed new generation and their state of permitting as well as renewable energy programs.

Section C
Potential Retirement of Old Thermal Generation Including Those That Utilize Once-Thru Cooling Systems

Since 2003, the California Energy Commission (CEC) has outlined in their Integrated Energy Policy Report (IEPR) the need to address aging thermal power plants and therefore facilitate their replacement. Their 2005 IEPR located on the CEC's web site at http://www.energy.ca.gov/2005_energypolicy/index.html includes a list of the generator units considered in the group. The requirement to mitigate for the impact of once-thru cooling systems utilized by some thermal power plants is documents both on the California Water Resources Control Board web site at http://www.waterboards.ca.gov/npdes/cwa316.html and on the CEC web site at http://www.energy.ca.gov/siting/once_through_cooling.html. Both are captured within a CAISO stakeholder activity presently in progress where related documents are located on the CAISO's web site at http://www.caiso.com/1c58/1c58e7a3257a0.html.

An illustration of a technical study and CAISO stakeholder activity that has completed the initial phase of establishing a plan for maintaining long-term reliable load serving capability within the San Francisco Greater Bay Area while taking into account mitigation of reliance on several olf thermal generating units that also utilize once-thru cooling systems is located on the CAISO's web site at http://www.caiso.com/1c64/1c64bb9743ee0.html.

The Participating transmission Owners (PTOs), through their annual transmission expansion planning processes will also continue to analyze retirement scenarios and develop transmission plans to address any identified reliability concerns. The purpose of conducting studies with these generating units out of service is to gain an understanding of the potential impacts on the grid of these retirements well in advance of the actual retirement announcement and therefore have mitigation plans in place when required.

In addition, Load Serving Entities (LSEs) will be able to use this information in their integrated resource planning and generation procurement processes, such as to decide whether to procure power from these resources, from new resources in the vicinity of the old resources, or from remote resources in conjunction with any required transmission reinforcements.

This approach to planning for retirements has been developed to enable the CAISO and the PTOs to be more proactive in planning the grid. The alternative to these studies would be to simply wait until a generator announces retirement and then initiate a study. If it was determined that the generator is necessary for reliability within the CAISO's Locational Capacity Requirements Study, the unit would continue in operation much longer than otherwise.

IV. ISO Grid Planning Guides for New Generator Special Protection Systems

As stated in the NERC/WSCC Planning Standards, the function of a Special Protection System (SPS) is to: "detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance." In the context of new generation projects, the possible action of a SPS portion at the generating plant would be to detect a transmission outage (either a single or credible multiple contingency) or an overloaded transmission facility and then trip or run back generation output to avoid potential overloaded facilities or other criteria violations. A power plant SPS can also have different functions, e.g. executing plant generation reduction, requested by other SPS; detecting unit outages and transmitting commands to other locations; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping, etc. The alternatives and supplements to these actions are different actions outside the plant (including load trip), pre-contingency generation curtailment or new transmission facilities.

The primary reasons why a SPS might be selected over new transmission facilities are that a SPS can normally be implemented much more quickly and for a much lower cost. In addition, a SPS can increase the utilization of the existing transmission facilities and make better use of scarce transmission resources. Due to these advantages, a SPS is an alternative commonly proposed as a cost-effective method of integrating new generation into the grid while maintaining system reliability. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of a SPS, there can be increased exposure to potential criteria violations, transmission outages can become more difficult to schedule, and the system can become more difficult to operate. If there are a large number of SPSs, it may become difficult to assess the interdependency of these SPSs on system reliability. It is these reliability concerns that have led to the development of the additional guides in this document concerning the application of SPS. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of the existing transmission facilities while maintaining system reliability and operability. The need for these guides has become more critical as a result of the large number of new generators that are currently planning to connect to the ISO Grid.

It needs to be emphasized that these are guides rather than standards. This is to emphasize that judgment will need to be used by system planners and operators in determining when the application of SPS will be acceptable. It is recognized that it is not possible or desirable to have strict standards for the acceptability of the use of a SPS in all potential applications.

California ISO New Generator SPS Guidelines

ISO G1. The overall reliability of the system should not be degraded after the combined addition of the SPS and the generator, nor should the SPS add complexity to real-time operation or result in the system losing operating flexibility.

ISO G2. The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. To meet this requirement, the SPS may need to be fully redundant.

ISO G3. The SPS must be fully automatic, including arming, as much as practical.

ISO G4. The total net amount of generation tripped by a SPS for a single contingency cannot exceed the ISO's largest single generation contingency (currently one Diablo Canyon unit at 1150 MW). The total net amount of generation tripped by a SPS for a double contingency cannot exceed 1400 MW. This amount is related to the minimum amount of spinning reserves that the ISO has historically been required to carry. The quantities of generation specified in this standard represent the current upper limits for generation tripping. These quantities will be reviewed periodically and may increase or decrease. In addition, the actual amount of generation that can be tripped is project specific and may depend on the reliability criteria violations to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts shown in this guide. The net amount of generation is the gross plant output less the load (plant and other) tripped by the same SPS.

ISO G5. For SPSs designed to protect against single contingency outages, the following consequences are normally unacceptable should the SPS fail to operate correctly (even for a fully redundant SPS):

A) Cascading outages beyond the outage of the facility that the SPS is intended to protect: For example, if a SPS were to fail to operate as designed for a single contingency and the line the SPS was intended to protect were to trip on overload protection, then the subsequent loss of additional facilities due to overloads or system stability would not be an acceptable consequence.

B) Voltage instability, transient instability, or small signal instability: While these are rarely concerns associated with the addition of new generation, the consequences can be so severe that they are deemed to be unacceptable results following SPS failure.

These restrictions apply to single contingency outages and not double contingency outages due to the much higher probability of occurrence of single contingency outages.

ISO G6. Close coordination of SPS is required to eliminate cascading events. All SPS in a local area (such as SDG&E, Fresno etc) and grid-wide need to be evaluated as a whole and studied as such.

ISO G7. The SPS must be simple and manageable. As a general guideline:

A) There should be no more than 6 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS.

B) The SPS should not be monitoring more than 4 system elements or variables. A variable can be a combination of related elements, such as a path flow, if it is used as a single variable in the logic equation. Exceptions include:

- The number of elements or variables being monitored may be increased if it results in the elimination of unnecessary actions, for example: generation tripping, line sectionalizing or load shedding.
- If the new SPS is part of an existing SPS that is triggered by more than 4 local contingencies or that monitors more than 4 system elements or variables, then the new generation cannot materially increase the complexity of the existing SPS scheme. However, additions to an existing SPS using a modular design should be considered as preferable to the addition of a new SPS that deals with the same contingencies covered by an existing SPS.

C) Generally, the SPS should only monitor facilities that are connected to the plant or to the first point of interconnection with the grid. Monitoring remote facilities may add substantial complexity to system operation and should be avoided, if possible.

D) An SPS should not require real time operator actions to arm or disarm the SPS or change its set points.

ISO G8. The SPS may not include the involuntary interruption of load. Voluntary interruption of load paid for by the generator is acceptable. The exception is that the new generator can be added to an existing SPS that includes involuntary load tripping. However, the amount of involuntary load tripped by the combined SPS may not be increased as a result of the addition of the generator.

ISO G9. Action of the SPS shall limit the post-disturbance loadings and voltages on the system to be within all applicable ratings and shall ultimately bring the system to within the long-term (4 hour or longer) emergency ratings of the transmission equipment or to the loading levels that would exist on the system prior to the addition of the new generator. For example, the operation of a SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back generation to bring the line loading to be within the line’s 4 hour or longer rating.

ISO G10. The SPS should not run-back or trip existing Reliability Must-Run generators unless there is no plausible expectation that the ISO would call upon such generators for reliability purposes during the periods where the SPS would be armed.

ISO G11 The SPS needs to be approved by the ISO and may need to be approved by the WSCC Remedial Action Scheme Reliability Task Force.

ISO G12 The CA-ISO, in coordination with affected parties, may relax SPS requirements as a temporary bridge to system reinforcements. Normally this bridging period would be limited to the time it takes to implement a specified alternative solution. An example of a relaxation of a SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events.

ISO G13 The ISO will consider the expected frequency of operation in its review of SPS proposals.

ISO G14 In general, these guidelines are intended to be applied with more flexibility for low exposure outages (e.g., double line outages, bus outages, etc.) than for high exposure outages (e.g., single contingencies).

ISO G15 The actual performance of existing and new SPS schemes will be documented by the transmission owners and periodically reviewed by the ISO and other interested parties so that poorly performing schemes may be identified and revised.

ISO G16 All SPS schemes will be documented by the owner of the transmission system where the SPS exists. The generation owner, the transmission owner, and the ISO shall retain copies of this documentation. To facilitate transmission system studies, documentation will be made available to others upon request to the ISO.

ISO G17 Normally, the transmission owner, in coordination with affected parties, will be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO G18 Generally, the generating units tripped by the SPS should be highly effective in reducing the loadings on the facilities of concerns.

ISO G19 Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO will normally be required. Specific telemetry requirements will be determined on a project specific basis.

V. Combined Line and Generator Unit Outage Standards Supporting Information

Combined Line and Generator Outage Standard - A single transmission circuit outage with one generator already out of service and the system adjusted shall meet the performance requirements of the NERC Planning Standards for Category B contingencies.

The CAISO states that while an over-lapping outage of a generator unit (G-1) and transmission line (L-1) is defined within NERC Planning Standards as a Category C (NERC Standard TPL-003) contingency, the CAISO Grid Planning Standards include that this contingency meet Category B (NERC Standard TPL-002) contingency requirements. Therefore, for this combined outage, no interruption of customer load is allowed.

NERC standards are minimum standards, where additional requirements are allowed, such as this CAISO Combined Line and Generator Outage Standard. FERC allows individual areas to have standards different from NERC Reliability Standards if they are more stringent. Use of this standard has provided necessary “additional room” on a day-to-day operating basis, when more than one generating unit is out of service at any given time.

Currently, all PTOs under CAISO jurisdiction treat an overlapping G-1 and L-1 scenario as a Category B event and accordingly, transmission system reinforcements are implemented when potential reliability problems that violate the criteria are identified. Historical data shows that the frequency of having a generator unit out is much greater than a transmission line and therefore the probability of an overlapping G-1 and an L-1 is much greater than the probability of a double-line outage (L-2) event since generation and transmission outage events are, for the most part, independent of each other. Loss of a single generator (planned or forced) can even be a pre-existing condition when the L-1 event occurs and time does not allow any outage coordination before occurrence of the second event. From an assessment of historical performance of generation and transmission, it can be concluded that the cost of additional transmission to avoid load interruption for this type of outage is well worth it from the customers’ perspective. This standard was utilized by the California Investor Owned Utilities prior to creation of the CAISO and therefore continues to be utilized. California legislation creating the CAISO prohibits progressing to a lower day to day state of reliability. Hence system reliability continues to be prudently protected by implementing transmission system upgrades to avoid a violation of this criteria. Any modification or deviation from the existing definition of this event classification will create additional exposure within the bulk transmission system and degrade reliability which is unacceptable to all PTOs in CAISO jurisdiction.

An exemption from this standard requires a probabilistic analysis of the potentially impacted system and be demonstrated that the customers’ expected value of the service interrupted during an over-lapping G-1 and L-1 would be less than the cost of added transmission reinforcement to protect against the outage? CAISO standards allow for obtaining an exemption to this standard in specific instances where it is economically justified. NERC Standards include a table illustrating the allowable impact of maintaining various levels of reliability. This table includes is a footnote for single contingencies where “Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted Element” is allowed.

VI. Background behind the New Transmission versus Involuntary Load Interruption Standard

For practical and economic reasons, all electric transmission systems are planned to allow for some involuntary loss of firm load under some contingency conditions. For some systems, such a loss of load may require several contingencies to occur while for other systems, loss of load may occur in the event of specific single contingencies. Historically, there has been a wide variation in approaches exists among the California ISO PTOs. One PTO may allow involuntary loss of load following a specific type of contingency while another PTO would build a project to prevent loss of load for the same type of contingency. This standard is intended to lead to the elimination of these inconsistencies and also to provide the information needed to help ensure that the ISO is making cost effective transmission system additions.

This standard is also a change in the approach the ISO uses in planning from primarily deterministic planning standards[1] toward probabilistic planning standards. It is the general belief of the PSC that this trend will be an improvement in that it will provide additional information for the ISO and others to use when making decisions associated with making improvements to the grid. It is the intent of the PSC that the implementation of these principles should not result in lower levels of reliability to end-use customers than existed prior to restructuring.

To implement this standard, the following process will be used:

1) **Identification of Reliability Concerns:** As part of the PTO's annual transmission expansion plans, each PTO will identify those ISO Category B outages that would require the involuntary interruption of load either as a result of the system configuration (i.e., such as for a radial system) or because interrupting load was necessary to meet the ISO Grid Planning Standards.

    2) **Information Gathering:** For each of the ISO Category B outages that required involuntary interruption of load, the PTOs will estimate the following:

- The maximum amount of load that would need to be interrupted
- The duration of the interruption
- The annual energy that would not be served or delivered
- The number of interruptions per year
- The time of occurrence of the interruption (e.g., weekday summer afternoon)
- The number of customers that would be interrupted
- The composition of the load (i.e., the percent residential, commercial, industrial, and agricultural)
- Value of Service or Performance Based Ratemaking assumptions concerning the dollar impact of a load interruption

The above information will be documented in the PTO's Transmission Expansion Plans. Using this information, the PTOs and other interested stakeholders can estimate the benefit to the end-use customers of reducing the likelihood of interruption.

[1] An example of a purely deterministic standard is the following: There should be no more than 200 MW of load loss for a double contingency.

3) PTO Recommendations: As part of the evaluation of alternatives in the PTO's Five-Year Transmission Expansion Plans, the PTOs will propose either projects or operating procedures[2] to be the appropriate solution to address identified reliability criteria violations. The PTOs shall also provide their rationale for selecting either an operating procedure or a project.

4) Cost-Benefit Estimates: The PTO will estimate the costs[3] and benefits of projects to remedy the reliability concerns identified in 1) above. In addition to developing new projects, the PTOs will review currently approved projects to determine if they would still propose to construct those projects or propose an alternative solution.

For cases where the PTO has proposed an operating procedure that involves the interruption of load to be the appropriate solution, the PTOs will estimate the following:

- The future frequency and duration of outages for impacted substations
- The historical frequency and duration of outages for impacted substations
- The communities served by these substations

5) Notification: All of the above information will be provided to the stakeholders as part of the Transmission Expansion Plan prior to an ISO decision to accept or reject PTO-proposed involuntary load dropping in lieu of transmission reinforcement. The information will be made available in a timely manner so that customers can intervene before the ISO Board if they desire.

One way the information could be provided would be to develop a table such as the following:

<u>Projected and Historical Reliability Data for Single Contingencies that can Result in Load Interruptions</u>

Case	Area Affected		Possible Future Outage Without Project		Possible Future Outage With Project	
	Substations, Feeders, & Peak MW	Communities	Frequency	Duration	Frequency	Duration

6) ISO Review and Approval: The ISO, with input from the PTOs and other stakeholders, will review the PTO's five-year plans and determine whether to adopt the PTO's proposed

[2] The proposed operating procedures shall be in sufficient detail in concept and application so as to allow review and approval in principle in lieu of upgrade projects.

[3] Project costs may need to be handled as confidential information.

projects or operating procedures[4]. The final ISO approved plan will be distributed to the stakeholders.

7) Periodic Reevaluation: Cases where it has been decided by the ISO Board to plan for involuntary load interruptions rather than a project (transmission, generation, or load reduction) will be re-evaluated every three years or more frequently if merited by load growth or system changes or if the reliability in that area has significantly deteriorated.

VII. Background behind the San Francisco Greater Bay Area Generation Outage Standard (In the process of being revised)

On June 14, 2000, rolling blackouts were initiated in the San Francisco Bay area to protect against the potential for voltage collapse. The major reason behind the need to implement rolling blackouts was the large number of generating units that were forced out of service on that day. The problem had not been uncovered in the planning studies for the area because the current ISO Grid Planning Standards only require that a single generating unit be assumed out of service in combination with the most critical transmission line. As a result of the June 14, 2000 rolling blackouts, the ISO Grid Planning Standards Committee was tasked with reviewing the ISO Grid Planning Standards to determine whether they need to be revised.

As a result of this review, the ISO Grid Planning Standards Committee determined that, while the normal standard of planning for one generating unit in combination with one transmission line out is adequate for most of the ISO Grid, it is inadequate for the greater San Francisco Bay area. In the Bay area, there is an unusually large concentration of generating units (more than 30) which increases the likelihood that more than one unit could be forced out of service at a given time. In addition, the historical forced outage rates for the units in the Bay area are significantly higher than the industry averages for similar units resulting in a higher probability of such multiple outage occurrences. The higher forced outage rates are at least partially due to the age of the units. Based on this information, and discussion at six stakeholder meetings where a variety of approaches to potential new standards were considered, the San Francisco Greater Bay Area Generation Outage Standard was developed.

While this proposed standard only applies to the San Francisco Bay Area, the ISO Grid Planning Standards Committee will periodically review various areas of the ISO Grid to determine if additional specific standards are warranted to address issues unique to those areas.

The ISO Grid Planning Standards Committee will review this standard periodically. This review will require forced and scheduled outage data for all generating units in the area.

The following tables provide the statistical basis for the work that has been completed by the ISO Grid Planning Standards Committee. This data was provided by PG&E and is based on outage data available to PG&E during their ownership of the units prior to the formation of the CAISO. It is assumed for this analysis that outage data will be similar under the present

[4] Proposed operating procedures will be reviewed by the ISO to determine whether they can be reasonably implemented.

ownership of the units. For a description of how the data was compiled or computed, please refer to the original report that was prepared by Anatoliy Meklin of PG&E. The report is entitled "STATISTICAL ANALYSIS OF SIMULTANEOUS FORCED OUTAGES IN BAY AREA" and dated October 31, 2000.

Table 1. Forced Outage Data for Bay Area Generators

Name	MW	T2 - hours between forced outages		T1 - hours of forced outages	
		Mean	Standard deviation	Mean	Standard deviation
OAKLND 1	55	2130	1978	521	1150
OAKLND 2	55	4804	6612	306	649
OAKLND 3	55	4352	4399	29	17
ChevGen1	54	1475	1032	25	18
ChevGen2	54	1475	1032	25	18
PDEFCT2	199	1475	1032	25	18
PDEFCT1	199	1475	1032	25	18
PDEFST1	280	1475	1032	25	18
PTSB 1	170	1720	2078	79	75
PTSB 2	170	2448	1986	622	1925
PTSB 3	170	1520	1549	570	873
PTSB 4	170	2307	2048	153	138
PTSB 5	325	1798	2389	262	373
PTSB 6	325	4596	3773	67	48
PTSB 7	710	3252	6196	147	131
MOSS 5	750	2735	1416	64	35
MOSS 6	750	1626	1970	94	94
C.COS 6	340	1930	1522	429	1365
C.COS 7	340	1158	843	41	57
POTRERO3	210	3090	3156	212	186
POTRERO4	52	4705	6151	253	242
POTRERO5	52	13090	6869	75	35
POTRERO6	52	5596	9842	47	41
HNTRS P2	108	2047	1961	129	160
HNTRS P3	108	3207	4253	76	51
HNTRS P4	170	3165	4511	130	146
HNTRS P1	52	7856	7498	55	31
GLRY COG	130	1445	1010	55	38
FMC CT	52	1445	1010	55	38

Table 2. NERC Forced Outage Data for Selected Types of Units

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	FOF (%)	Assuming 6 outages per year	
					T2 - hours between forced outages	T1 – hours of forced outages
FOSSIL	All Sizes	1,532	7,126	3.82	1408	56
All Fuel Types	1-99	351	1,486	3.18	1417	47
	100-199	426	2,016	3.45	1413	51
	200-299	171	825	3.68	1410	54
	300-399	147	717	5.07	1390	74
	400-599	262	1,250	4.29	1401	63
	600-799	127	602	4.22	1402	62
	800-999	34	165	3.48	1413	51
	1000 Plus	14	65	5.78	1379	85
Gas Primary	All Sizes	466	1,965	3.58	1412	52
	1-99	145	554	3.53	1412	52
	100-199	147	624	3.61	1411	53
	200-299	47	211	2.31	1430	34
	300-399	41	188	4.33	1401	63
	400-599	63	296	3.92	1407	57
	600-799	20	81	4.27	1401	63
	800-999	3	11	1.50	1442	22
Gas Turbine	All Sizes	768	3,475	3.84	1408	56
	20-49	251	1,161	5.60	1382	82
	50 Plus	318	1,386	2.12	1433	31
Comb. Cycle	All Sizes	58	242	1.50	1442	22

Table 3. Probabilities of Simultaneous Forced Outages of Generators
(Actual Greater Bay Area Data)

# of generators in forced outage	% of year	% of year if in peak
>=1	91	8.1
>=2	68	6.2
>=3	40	3.7
>=4	17	1.6
>=5	6	0.6

Observations:

- One out of 30 generators is unavailable 91 % of time
- The probability of simultaneous forced unit outages is very high and two units are unavailable 68% of the time
- The coincident forced outage of 5 generators could occur for 520 hours/year or 52 peak-hours/year.
- The probability of having 5 generators forced out of service in the Greater Bay Area is 20 times higher using actual historical data than it would be if the units had typical NERC forced outage rates as shown in Table 4.

Table 4. Probabilities of Simultaneous Forced Outages of Generators
(NERC Data)

# of generators in forced outage	% of year	% of year if in peak
>=1	67	5.8
>=2	28	2.4
>=3	8.3	0.72
>=4	1.59	0.15
>=5	0.22	0.03

Observations:

- The lower generator forced outage rates in the NERC data result in a much lower probability for multiple unit outages.

Table 5. Probabilities of Simultaneous Forced Outages of Megawatts (Using Actual Data).

Unavailable MW	% of year	% of year if in peak	occurrences/year	occurrences/year if in peak
in forced outage			(as result of a forced outage event with loss of >100 MW)	(as result of a forced outage event with loss of >100 MW)
>=100	88.2	7.7	60.44	5.55
>=200	74.9	6.4	54.31	4.8
>=300	66.2	5.65	49.93	4.48
>=400	48.3	4.07	40.30	3.71
>=500	42.6	3.56	35.92	3.30
>=600	28.8	2.4	26.28	2.53
>=700	20.7	1.69	20.15	2.07
>=800	15.2	1.21	20.15	1.59
>=900	10.8	0.92	12.26	1.31
>=1000	8.0	0.69	9.64	1.05
>=1100	5.5	0.46	7.01	0.61
>=1200	4.0	0.34	5.26	0.44
>=1300	2.7	0.21	3.50	0.32
>=1400	1.8	0.12	2.63	0.22
>=1500	0.9	0.07	1.75	0.16
>=1600	0.6	0.04	0.88	0.11

Note: Peak hours make up about 8.8% of the year.

VIII - North American Electric Reliability Council (NERC) Transmission Planning Standards

Standards Title:	System Performance Under Normal (No Contingency) Conditions (Category A)
Number:	TPL-001-0
	System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
Purpose:	
Requirement Number	**Text of Requirement**
R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
R1.1.	Be made annually.
R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
R1.3.1.	Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
R1.3.2.	Be conducted annually unless changes to system conditions do not warrant such analyses.
R1.3.3.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
R1.3.4.	Have established normal (pre-contingency) operating procedures in place.
R1.3.5.	Have all projected firm transfers modeled.
R1.3.6.	Be performed for selected demand levels over the range of forecast system demands.
R1.3.7.	Demonstrate that system performance meets Table 1 for Category A (no contingencies).
R1.3.8.	Include existing and planned facilities.
R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
R1.4.	Address any planned upgrades needed to meet the performance requirements of Category A.
R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:
R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1.	Including a schedule for implementation.
R2.1.2.	Including a discussion of expected required in-service dates of facilities.
R2.1.3.	Consider lead times necessary to implement plans.
R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
R3.	The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.
MEASURES	**Details or N/A**
M1	The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R2.1 and TPL-001-0_R2.2.
M2	The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.
DATA RETENTION	**Details OR On-Going**
	None specified.

Standards Title:	System Performance Following Loss of a Single Bulk Electric System Element (Category B)
Number:	TPL-002-0
	System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
Purpose:	
Requirement Number	**Text of Requirement**
R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessme of the interconnected transmission system is planned such that the Network can be operated to supp customer demands and projected Firm (non-recallable reserved) Transmission Services, at all dema the range of forecast system demands, under the contingency conditions as defined in Category B o valid, the Planning Authority and Transmission Planner assessments shall:
R1.1.	Be made annually.
R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) plannin
R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the categories,, showing system performance following Category B of Table 1 (single contingencies). Th elements selected (from each of the following categories) for inclusion in these studies and simulatio acceptable to the associated Regional Reliability Organization(s).
R1.3.1.	Be performed and evaluated only for those Category B contingencies that would produce the more s results or impacts. The rationale for the contingencies selected for evaluation shall be available as s information. An explanation of why the remaining simulations would produce less severe system res available as supporting information.
R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.
R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions longer lead-time solutions.
R1.3.5.	Have all projected firm transfers modeled.
R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system Demands
R1.3.7.	Demonstrate that system performance meets Category B contingencies.
R1.3.8.	Include existing and planned facilities.
R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet performance.
R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant sy
R1.3.11.	Include the effects of existing and planned control devices.
R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protect their components) at those demand levels for which planned (including maintenance) outages are pe
R1.4.	Address any planned upgrades needed to meet the performance requirements of Category B of Tab
R1.5.	Consider all contingencies applicable to Category B.
R2.	When System simulations indicate an inability of the systems to respond as prescribed in Reliability 002-0_R1, the Planning Authority and Transmission Planner shall each:
R2.1.	Provide a written summary of its plans to achieve the required system performance as described abo the planning horizon:
R2.1.1.	Including a schedule for implementation.
R2.1.2.	Including a discussion of expected required in-service dates of facilities.
R2.1.3.	Consider lead times necessary to implement plans.
R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need system facilities. Detailed implementation plans are not needed.
R3.	The Planning Authority and Transmission Planner shall each document the results of its Reliability A corrective plans and shall annually provide the results to its respective Regional Reliability Organizat required by the Regional Reliability Organization.
MEASURES	**Details or N/A**
M1	The Planning Authority and Transmission Planner shall have a valid assessment and corrective plan Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.
M2	The Planning Authority and Transmission Planner shall have evidence it reported documentation of r reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.
DATA RETENTION	**Details OR On-Going**
	None specified.

Standards Title:	System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
Number:	TPL-003-0
	System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
Purpose:	

Requirement Number	Text of Requirement
R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
R1.1.	Be made annually.
R1.2.	Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
R1.3.1.	Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.
R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.
R1.3.4.	Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
R1.3.5.	Have all projected firm transfers modeled.
R1.3.6.	Be performed and evaluated for selected demand levels over the range of forecast system demands.
R1.3.7.	Demonstrate that System performance meets Table 1 for Category C contingencies.
R1.3.8.	Include existing and planned facilities.
R1.3.9.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
R1.3.10.	Include the effects of existing and planned protection systems, including any backup or redundant systems.
R1.3.11.	Include the effects of existing and planned control devices.
R1.3.12.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
R1.4.	Address any planned upgrades needed to meet the performance requirements of Category C.
R1.5.	Consider all contingencies applicable to Category C.
R2.	When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1.	Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
R2.1.1.	Including a schedule for implementation.
R2.1.2.	Including a discussion of expected required in-service dates of facilities.
R2.1.3.	Consider lead times necessary to implement plans.
R2.2.	Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
R3.	The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.
MEASURES	**Details or N/A**
M1	The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.
M2	The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.
DATA RETENTION	**Details OR On-Going**
	None specified.

Standards Title:	System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
Number:	TPL-004-0
	System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
Purpose:	
Requirement Number	**Text of Requirement**
R1.	The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
R1.1.	Be made annually.
R1.2.	Be conducted for near-term (years one through five).
R1.3.	Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1.	Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
R1.3.2.	Cover critical system conditions and study years as deemed appropriate by the responsible entity.
R1.3.3.	Be conducted annually unless changes to system conditions do not warrant such analyses.
R1.3.4.	Have all projected firm transfers modeled.
R1.3.5.	Include existing and planned facilities.
R1.3.6.	Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
R1.3.7.	Include the effects of existing and planned protection systems, including any backup or redundant systems.
R1.3.8.	Include the effects of existing and planned control devices.
R1.3.9.	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
R1.4.	Consider all contingencies applicable to Category D.
R2.	The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.
MEASURES	**Details or N/A**
M1	The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.
M2	The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.
DATA RETENTION	**Details OR On-Going**
	None specified.