



California ISO Planning Standards

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I. Introduction

The California ISO (ISO) tariff provides for the establishment of planning guidelines and standards above those established by NERC and WECC to ensure the secure and reliable operation of the ISO controlled grid. The primary guiding principle of these Planning Standards is to develop consistent reliability standards for the ISO grid that will maintain or improve transmission system reliability to a level appropriate for the California system.

These ISO Planning Standards are not intended to duplicate the NERC and WECC reliability standards, but to complement them where it is in the best interests of the security and reliability of the ISO controlled grid. The ISO planning standards will be revised from time to time to ensure they are consistent with the current state of the electrical industry and in conformance with NERC Reliability Standards and WECC Regional Criteria. In particular, the ISO planning standards:

- Address specifics not covered in the NERC Reliability Standards and WECC Regional Criteria;
- Provide interpretations of the NERC Reliability Standards and WECC Regional Criteria specific to the ISO Grid;
- Identify whether specific criteria should be adopted that are more stringent than the NERC Reliability Standards and WECC Regional Criteria where it is in the best interest of ensuring the ISO controlled grid remains secure and reliable.

NERC Reliability Standards and WECC Regional Criteria:

The following links provide the minimum standards that ISO needs to follow in its planning process unless NERC or WECC formally grants an exemption or deference to the ISO. They are the NERC Transmission Planning (TPL) standards, other applicable NERC standards (i.e., NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant), and the WECC Regional Criteria:

<http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States>

<https://www.wecc.biz/Standards/Pages/Default.aspx>

Section II of this document provides additional details about the ISO Planning Standards. Guidelines are provided in subsequent sections to address certain ISO planning standards, such as the use of new Special Protection Systems, which are not specifically addressed at the regional level of NERC and WECC. Where appropriate, background information behind the development of these standards and references (web links) to subjects associated with reliable transmission planning and operation are provided.

II. ISO Planning Standards

The ISO Planning Standards are:

1. Applicability of ~~NERC~~ Reliability Standards to non-Bulk Electric System Low Voltage Facilities under ISO Operational Control

~~In planning for identified non-BES facilities, according to NERC Bulk Electric System definition and WECC BES Inclusion and Exclusion Guidelines, that have been turned over to the ISO operational control, the ISO will apply the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant, the approved WECC Regional Criteria and NERC Transmission Planning (TPL) standard TPL-001-4 categories P0, P1 and P3 contingencies taken on the non-BES equipment. All other NERC Transmission Planning (TPL) standard TPL-001-4 categories of contingencies taken on non-BES equipment may be evaluated for risk and consequences and may be used for project justification in conjunction with reduction in load outage exposure, through a benefit to cost ratio (BCR) under standard 5 section 4 herein. The ISO will apply NERC Transmission Planning (TPL) standards, the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for Diablo Canyon Power Plant, and the approved WECC Regional Criteria to facilities with voltages levels less than 100 kV or otherwise not covered under the NERC Bulk Electric System definition that have been turned over to the ISO operational control.~~

2. Voltage Standard

Voltage and system performance must meet WECC Regional Criteria TPL-001-WECC-CRT-3 <https://www.wecc.biz/Reliability/TPL-001-WECC-CRT-3.1.pdf>.

In accordance with Requirements WR2 and WR3 of WECC Regional Criteria TPL-001-WECC-CRT-3 the following standards and limits are to be used within the ISO controlled grid.

Table 1: ISO steady state voltage standard.

Voltage level	Normal Conditions (P0)		Contingency Conditions (P1-P7)		Voltage Deviation P1&P3
	Vmax (pu)	Vmin (pu)	Vmax (pu)	Vmin (pu)	
≤ 200 kV	1.05	0.95	1.10	0.90	≤8%
≥ 200 kV	1.05	0.95	1.10	0.90	≤8%
≥ 500 kV	1.05	1.00	1.10	0.90	≤8%

The voltage deviation applies only to load and generating buses within the ISO controlled grid (including generator auxiliary load). The maximum total voltage deviation for standard TPL-001-4 category P3 is ≤8% measured from the voltage that exists after the initial condition (loss of generator unit followed by system

adjustments) and therefore takes into consideration only voltage deviation due to the second event.

All buses within the ISO controlled grid that cannot meet the requirements specified in Table 1 will require further investigation. Exceptions to this voltage standard may be granted by the ISO and will be documented through stakeholder process. The ISO will make public all exceptions through its website.

Exceptions and clarifications by PTO area:

Table 2: System Voltage Limits in SCE Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
All buses	525 kV	540/1.029	520/0.990	550/1.048 ²	498.8/0.950
Alamitos, Arcogen, Huntington Beach, Mandalay, Redondo	230 kV	230/1.000 ¹	220/0.957	230/1.000 ²	207/0.900

¹ Due to equipment (circuit breaker) voltage limit.

Bailey, Chevmain, Cima, Colorado River, Cool Water, Eagle Mt., Eagle Rock, El Casco, Gene, Harborgren, Highwind, Iron Mt., Inyo, Ivanpah, Johanna, Lewis, Primm, Rancho Vista, Red Bluff, Sandlot, Santiago, Serrano, Whirlwind, Windhub	230 kV	241.5/1.050	218.5/0.95	245/1.065 ²	207/0.900
All other buses	230 kV	241.5/1.050	218.5/0.95	242/1.052 ²	207/0.900
Eagle Mtn, Blythe	161 kV	169/1.050 ²	152.95/0.950	169/1.050 ²	144.9/0.900
Cool Water, Inyokern, Kramer, Victor	115 kV	120.75/1.050	109.25/0.950	121/1.052 ²	103.5/0.900
Control, Inyo	115 kV	120.75/1.05	117/1.026	121/1.052 ²	114.5/0.996
All other buses	115 kV	120.75/1.050	109.25/0.950	123/1.070 ²	103.5/0.900
All buses	66 kV	69.3/1.050	62.7/0.950	72.5/1.090 ²	59.4/0.900

Table 3: System Voltage Limits in PG&E Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
DCPP bus	500 kV	545/1.090	512/1.024	550/1.100	512/1.024
All other buses	500 kV	550/1.100	518/1.036	550/1.100	473/0.946
DCPP bus	230 kV	242/1.052	218/0.948	242/1.052	207/0.900
All other buses	230 kV	242/1.052	219/0.952	242/1.052	207/0.900
All buses	115 kV	121/1.052 ²	109/0.948	121/1.052 ¹	104/0.904
All buses	70 kV	72.5/1.036	66.5/0.950	72.5/1.036	63.0/0.900
All buses	60 kV	63.0/1.050	57.0/0.950	66.0/1.100	54.0/0.900

Maximum voltage deviation: DCPP 230 kV bus at 11 kV or 4.78%.

² PG&E Utility Standard TD1036S allows 115 kV voltages to operate as high as 126 kV until capital projects can be placed into service to achieve a desired operating limit of 121 kV.

Table 4: System Voltage Limits in SDG&E Area

Facility	Nominal Voltage	Steady State Pre-Contingency		Steady State Post-Contingency	
		High Limit (kV)	Low Limit (kV)	High Limit (kV)	Low Limit (kV)
All buses	525 kV	550/1.048	498.75/0.950	550/1.048	472.5/0.900
All buses	230 kV	241.5/1.050	218.5/0.950	241.5/1.050	207/0.900
All buses	138 kV	144.9/1.050	131.1/0.950	144.9/1.050	124.2/0.900
All buses	69 kV	72.45/1.050	65.55/0.950	72.45/1.050	62.1/0.900

Table 5: System Voltage Limits in VEA Area

System	Facility	Steady State Pre-Contingency		Steady State Post-Contingency	
		High (kV/p.u.)	Low (kV/p.u.)	High (kV/p.u.)	Low (kV/p.u.)
All buses	230 kV	248.4/1.080	218.5/0.950	253/1.100	207/0.900
All buses	138 kV	149.0/1.080	131.1/0.950	151.8/1.100	124.2/0.900

Table 6: System Voltage Limits for Trans Bay Cable

System	Facility	Steady State Pre-Contingency		Steady State Post-Contingency	
		High Limit (kV/p.u.)	Low Limit (kV/p.u.)	High Limit (kV/p.u.)	Low Limit (kV/p.u.)
All buses	230 kV	241.5/1.050	218.5/0.950	253/1.100	207/0.900
All buses	115 kV	120.75/1.050	109.25/0.950	126.5/1.100	103.5/0.900

3. Specific Nuclear Unit Standards

The criteria pertaining to the Diablo Canyon Power Plant (DCPP), as specified in the NUC-001 Nuclear Plant Interface Requirements (NPIRs) for DCPP, and Appendix E of the Transmission Control Agreement located on the ISO web site at: <http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=3972DF1A-2A18-4104-825C-E24350BA838F>

4. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard

A single module of a combined cycle power plant is considered a single contingency (G-1) and shall meet the performance requirements of the NERC TPL-001-4 standard for single contingencies (P1). Supporting information is located in Section IV of this document. Furthermore any reference to the loss of a “generator

unit” in the NERC multiple contingency standards (P3-P5) shall be similar to the loss of a “single module of a combined cycle power plant”.

A re-categorization of any combined cycle facility that falls under this standard to a less stringent requirement is allowed if the operating performance of the combined cycle facility demonstrates a re-categorization is warranted. The ISO will assess re-categorization on a case by case based on the following:

- a) Due to high historical outage rates in the first few years of operation no exceptions will be given for the first two years of operation of a new combined cycle module.
- b) After two years, an exception can be given upon request if historical data proves that no outage of the combined cycle module was encountered since start-up.
- c) After three years, an exception can be given upon request if historical data proves that outage frequency is less than once in three years.

The ISO may withdraw the re-categorization if the operating performance of the combined cycle facility demonstrates that the combined cycle module exceeds a failure rate of once in three year. The ISO will make public all exceptions through its website.

5. Planning for New Transmission versus Involuntary Load Interruption Standard

This standard sets out when it is necessary to upgrade the transmission system from a radial to a looped configuration or to eliminate load dropping otherwise permitted by WECC and NERC planning standards through transmission infrastructure improvements. It does not address all circumstances under which load dropping is permitted under NERC and WECC planning standards.

1. No single contingency (TPL-001-4 P1) should result in loss of more than 250 MW of load.
2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines “closed in” during normal operation.
3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more constraining.
4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

6. Planning for High Density Urban Load Area Standard

6.1 Local Area Planning

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources.³ The local areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local generation and transmission capacity. Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels.

For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

- In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.
- In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, number of customers impacted by the outage, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

6.2 System Wide Planning

System planning is characterized by much broader geographical size, with greater transmission import capability and most often with plentiful resources that usually

³ A “local area” for purposes of this Planning Standard is not necessarily the same as a Local Capacity Area as defined in the CAISO Tariff.

can be procured at somewhat lower prices than local area resources. Due to this fact more resources are available and are easier to find, procure and dispatch. Provided it is allowed under NERC reliability standards, the ISO will allow non-consequential load dropping system-wide SPS schemes that include some non-consequential load dropping to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

7. Extreme Event Reliability Standard

The requirements of NERC TPL-001-4 require Extreme Event contingencies to be assessed; however the standard does not require mitigation plans to be developed for these Extreme Events. The ISO has identified in Section 7.1 below that the San Francisco Peninsula area has unique characteristics requiring consideration of corrective action plans to mitigate the risk of extreme events. Other areas of the system may also be considered on a case-by-case basis as a part of the transmission planning assessments.

7.1 San Francisco-Peninsula - Extreme Event Reliability Standard

The ISO has determined through its Extreme Event assessments, conducted as a part of the annual transmission planning process, that there are unique characteristics of the San Francisco Peninsula area requiring consideration for mitigation as follows.

- high density urban load area,
- geographic and system configuration,
- potential risks of outages including seismic, third party action and collocating facilities; and
- challenging restoration times.

The unique characteristics of the San Francisco Peninsula form a credible basis for considering for approval corrective action plans to mitigate the risk of outages that are beyond the application of mitigation of extreme events in the reliability standards to the rest of the ISO controlled grid. The ISO will consider the overall impact of the mitigation on the identified risk and the associated benefits that the mitigation provides to the San Francisco Peninsula area.

8. Other Planning Standards

8.1 Local Capacity Area Technical Criteria

A Local Capacity Area, as defined in the ISO Tariff, is planned to meet the minimum performance established in mandatory standards as well as local capacity technical study criteria as defined in ISO Tariff section 40.3.1.1.

8.2 Required Maintenance Standard

Transmission and resource owners must be able to perform required maintenance, of reasonable time duration, on their BES and non-BES equipment during the year.

During transmission or resource maintenance the P0 and P1 performance requirements in NERC TPL-001-4 for either BES or non-BES facilities must be maintained. Corrective action(s) must be implemented when it is established through a combination of real-time data and technical studies that there is no window during the year to schedule the transmission or resource maintenance.

III. ISO Planning Guidelines

The ISO Planning Guidelines include the following:

1. Special Protection Systems

As stated in the NERC glossary, a Special Protection System (SPS) is “an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition of faulted components to maintain system reliability.” In the context of new projects, the possible action of an SPS would be to detect a transmission outage (either a single contingency or credible multiple contingencies) or an overloaded transmission facility and then curtail generation output and/or load in order to avoid potentially overloading facilities or prevent the situation of not meeting other system performance criteria. A SPS can also have different functions such as executing plant generation reduction requested by other SPS; detecting unit outages and transmitting commands to other locations for specific action to be taken; forced excitation pulsing; capacitor and reactor switching; out-of-step tripping; and load dropping among other things.

The primary reasons why SPS might be selected over building new transmission facilities are that SPS can normally be implemented much more quickly and at a much lower cost than constructing new infrastructure. In addition, SPS can increase the utilization of the existing transmission facilities, make better use of scarce transmission resources and maintain system reliability. Due to these advantages, SPS is a commonly considered alternative to building new infrastructure in an effort to keep costs down when integrating new generation into the grid and/or addressing reliability concerns under multiple contingency conditions. While SPSs have substantial advantages, they have disadvantages as well. With the increased transmission system utilization that comes with application of SPS, there can be increased exposure to not meeting system performance criteria if the SPS fails or inadvertently operates. Transmission outages can become more difficult to schedule due to increased flows across a larger portion of the year; and/or the system can become more difficult to operate because of the

independent nature of the SPS. If there are a large number of SPSs, it may become difficult to assess the interdependency of these various schemes on system reliability. These reliability concerns necessarily dictate that guidelines be established to ensure that performance of all SPSs are consistent across the ISO controlled grid. It is the intent of these guidelines to allow the use of SPSs to maximize the capability of existing transmission facilities while maintaining system reliability and optimizing operability of the ISO controlled grid. Needless to say, with the large number of generator interconnections that are occurring on the ISO controlled grid, the need for these guidelines has become more critical.

It needs to be emphasized that these are guidelines rather than standards and should be used in the development of any new SPS. 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). This is to emphasize that best engineering practice and judgment will need to be exercised 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 SPS in all potential applications.

ISO SPS1

The overall reliability of the system should not be degraded after the combined addition of the SPS.

ISO SPS2

The SPS needs to be highly reliable. Normally, SPS failure will need to be determined to be non-credible. In situations where the design of the SPS requires WECC approval, the WECC Remedial Action Scheme Design Guide will be followed.

ISO SPS3

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 revised as needed. In addition, the actual amount of generation that can be tripped is project specific and may depend on specific system performance issues to be addressed. Therefore, the amount of generation that can be tripped for a specific project may be lower than the amounts provided in this guide. The net amount of generation is the gross plant output less the plant's and other auxiliary load tripped by the same SPS.

ISO SPS4

For SPSs, the following consequences are unacceptable should the SPS fail to operate correctly:

- 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 transmission line that 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 rare 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.

ISO SPS5

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 SPS6

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

ISO SPS7

If the SPS is designed for new generation interconnection, 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 SPS8

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. For example, the operation of SPS may result in a transmission line initially being loaded at its one-hour rating. The SPS could then automatically trip or run-back additional generation (or trip load if not already addressed under ISO SPS7 above) to bring the line loading within the line's four-hour or longer rating. This is intended to minimize real-time operator intervention.

ISO SPS9

The SPS needs to be agreed upon by the ISO and may need to be approved by the WECC Remedial Action Scheme Reliability Task Force.

ISO SPS10

The 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 SPS requirement would be to allow 8 initiating events rather than limiting the SPS to 6 initiating events until the identified system reinforcements are placed into service.

ISO SPS11

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

ISO SPS12

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 SPS13

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.

ISO SPS14

To ensure that the ISO's transmission planning process consistently reflects the utilization of SPS in its annual plan, the ISO will maintain documentation of all SPS utilized to meet its reliability obligations under the NERC reliability standards, WECC regional criteria, and ISO planning standards.

ISO SPS15

The transmission owner in whose territory the SPS is installed will, in coordination with affected parties, be responsible for designing, installing, testing, documenting, and maintaining the SPS.

ISO SPS16 Generally, the SPS should trip load and/or resources that have the highest effectiveness factors to the constraints that need mitigation such that the magnitude of load and/or resources to be tripped is minimized. As a matter of principle, voluntary load tripping and other pre-determined mitigations should be implemented before involuntary load tripping is utilized.

ISO SPS17

Telemetry from the SPS (e.g., SPS status, overload status, etc.) to both the Transmission Owner and the ISO is required unless otherwise deemed unnecessary by the ISO. Specific telemetry requirements will be determined by the Transmission Owner and the ISO on a project specific basis.

IV. Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard Supporting Information

Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard - A single module of a combined cycle power plant is considered a single (G-1) contingency and shall meet the performance requirements of the NERC TPL-001-4 standard for single contingencies (P1).

The purpose of this standard is to require that an outage of any turbine element of a combustion turbine be considered as a single outage of the entire plant and therefore must meet the same performance level as the NERC TPL-001-4 standard P1.

The ISO has determined that, a combined cycle module should be treated as a single contingency. In making this determination, the ISO reviewed the actual operating experience to date with similar (but not identical) combined cycle units currently in operation in California. The ISO's determination is based in large part on the performance history of new combined cycle units and experience to date with these units. The number of combined cycle facility forced outages that have taken place does not support a double contingency categorization for combined cycle module units in general. It should be noted that all of the combined cycle units that are online today are treated as single contingencies.

Immediately after the first few combined cycle modules became operational, the ISO undertook a review of their performance. In defining the appropriate categorization for combined cycle modules, the ISO reviewed the forced outage history for the following three combined cycle facilities in California: Los Medanos Energy Center (Los

Medanos), Delta Energy Center (Delta), and Sutter Energy Center (Sutter)⁴. Los Medanos and Sutter have been in service since the summer of 2001, Delta has only been operational since early summer 2002.

Table 2 below sets forth the facility forced outages for each of these facilities after they went into operation (i.e. forced outages ⁵that resulted in an output of zero MWs.) The table demonstrates that facility forced outages have significantly exceeded once every 3 to 30 years. Moreover, the ISO considers that the level of facility forced outages is significantly above the once every 3 to 30 years even accounting for the fact that new combined cycle facilities tend to be less reliable during start-up periods and during the initial weeks of operation. For example, four of the forced outages that caused all the three units at Los Medanos to go off-line took place more than nine months after the facility went into operation.

Facility	Date	# units lost
Sutter ⁶	08/17/01	No visibility
Sutter	10/08/01	1 CT
Sutter	12/29/01	All 3
Sutter	04/15/02	1 CT + ST
Sutter	05/28/02	1 CT
Sutter	09/06/02	All 3
Los Medanos ⁷	10/04/01	All 3
Los Medanos	06/05/02	All 3
Los Medanos	06/17/02	All 3
Los Medanos	06/23/02	1CT+ST
Los Medanos	07/19/02	All 3
Los Medanos	07/23/02	1CT+ST
Los Medanos	09/12/02	All 3
Delta ⁸	06/23/02	All 4
Delta	06/29/02	2 CT's + ST
Delta	08/07/02	2 CT's + ST

Table 2: Forced outages that have resulted in 0 MW output from Sutter, Los Medanos and Delta after they became operational

⁴ Los Medanos and Sutter have two combustion turbines (CT's) and one steam turbine (ST) each in a 2x1 configuration. Delta has three combustion turbines (CT's) and one steam turbine (ST) in a 3x1 configuration. All three are owned by the Calpine Corporation.

⁵ Only forced outages due to failure at the power plant itself are reported, forced outages due to failure on the transmission system/switchyard are excluded. The fact that a facility experienced a forced outage on a particular day is public information. In fact, information on unavailable generating units has been posted daily on the ISO website since January 1, 2001. However, the ISO treats information regarding the cause of an outage as confidential information.

⁶ Data for Sutter is recorded from 07/03/01 to 08/10/02

⁷ Data for Los Medanos is recorded from 08/23/01 to 08/10/02

⁸ Data for Delta is recorded from 06/17/02 to 08/10/02

The ISO realizes that this data is very limited. Nevertheless, the data adequately justifies the current classification of each module of these three power plants as a single contingency.

V. Background behind Planning for 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 certain 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 a specific single contingency. Historically, a wide variation among the PTOs has existed predominantly due to slightly differing planning and design philosophies. This standard is intended to provide a consistent framework upon which involuntary load interruption decisions can be made by the ISO when planning infrastructure needs for the ISO controlled grid.

The overarching requirement is that implementation of these standards should not result in lower levels of reliability to end-use customers than existed prior to restructuring. As such, the following is required:

1. No single contingency (TPL-001-4 P1) may result in loss of more than 250 MW of load.

This standard is intended to coordinate ISO planning standards with the WECC requirement that all transmission outages with at least 300 MW or more be directly reported to WECC. It is the ISO's intent that no single contingency (TPL-001-4 P1) should trigger loss of 300 MW or more of load. The 250 MW level is chosen in order to allow for differences between the load forecast and actual real time load that can be higher in some instances than the forecast and to also allow time for transmission projects to become operational since some require 5-6 years of planning and permitting with inherent delays. It is also ISO's intent to put a cap on the radial and/or consequential loss of load allowed under NERC standard TPL-001-4 single contingencies (P1).

2. All single substations of 100 MW or more should be served through a looped system with at least two transmission lines "closed in" during normal operation.

This standard is intended to bring consistency between the PTOs' substation designs. It is not the ISO's intention to disallow substations with load below 100 MW from having looped connections; however it is ISO's intention that all substations with peak load above 100 MW must be connected through a looped configuration to the grid.

3. Existing radial loads with available back-tie(s) (drop and automatic or manual pick-up schemes) should have their back-up tie(s) sized at a minimum of 50% of the

yearly peak load or to accommodate the load 80% of the hours in a year (based on actual load shape for the area), whichever is more stringent.

This standard is intended to insure that the system is maintained at the level that existed prior to restructuring. It is obvious that as load grows, existing back-ties for radial loads (or remaining feed after a single contingency for looped substations) may not be able to pick up the entire load; therefore the reliability to customers connected to this system may deteriorate over time. It is the ISO's intention to establish a minimum level of back-up tie capability that needs to be maintained.

4. Upgrades to the system that are not required by the standards in 1, 2 and 3 above may be justified by eliminating or reducing load outage exposure through a benefit to cost ratio (BCR) above 1.0 and/or where there are other extenuating circumstances.

It is ISO's intention to allow the build-up of transmission projects that are proven to have a positive benefit to ratepayers by reducing load drop exposure.

Information Required for BCR calculation: For each of the outages that required involuntary interruption of load, the following should be estimated:

- 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., week day 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 ISO Transmission Plan for areas where additional transmission reinforcement is needed or justified through benefit to cost ratio determination.

VI. Background behind Planning for High Density Urban Load Area Standard for Local Areas

A local area is characterized by relatively small geographical size, with limited transmission import capability and most often with scarce resources that usually can be procured at somewhat higher prices than system resources. These areas are planned to meet the minimum performance established in mandatory standards or other historically established requirements, but tend to have little additional flexibility beyond the planned-for requirements taking into account both local resource and transmission

capacity. The need for system reinforcement in a number of local areas is expected to climb due to projected resource retirements, with single and double contingency conditions playing a material role in driving the need for reinforcement. Relying on load shedding on a broad basis to meet these emerging needs would run counter to historical and current practices, resulting in general deterioration of service levels. One of the fundamental ISO Tariff requirements is to maintain service reliability at pre-ISO levels, and it drives the need to codify the circumstances in which load shedding is not an acceptable long-term solution:

1. For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standard P1-P7 contingencies and impacts on the 115 kV or higher voltage systems.

This standard is intended to continue avoiding the need to drop load in high density urban load areas due to, among other reasons, high impacts to the community from hospitals and elevators to traffic lights and potential crime.

The following is a link to the 2010 Census Urban Area Reference Maps:

<http://www.census.gov/geo/maps-data/maps/2010ua.html>

This site has diagrams of the following urbanized areas which contain over one million persons.

Los Angeles--Long Beach--Anaheim, CA
San Francisco--Oakland, CA
San Diego, CA
Riverside--San Bernardino, CA
San Jose, CA

2. In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built.

This standard is intended to insure that a reliable transition exists between the time when problems could arise until long-term transmission upgrades are placed in service.

3. In considering if load shedding, where allowed by NERC standards, is a viable mitigation in either the near-term, or the long-term for local areas that would not call upon high density urban load, case-by-case assessments need to be considered. Assessments should take in consideration, but not limited to, risk assessment of the outage(s) that would activate the SPS including common right of way, common structures, history of fires, history of lightning, common

substations, restoration time, coordination among parties required to operate pertinent part of the transmission system, number of resources in the area, outage history for resources in the area, retirement impacts, and outage data for the local area due to unrelated events.

It is ISO's intention to thoroughly evaluate the risk of outages and their consequences any time a load shedding SPS is proposed regardless of population density.

VII. Interpretations of terms from NERC Reliability Standard and WECC Regional Criteria

Listed below are several ISO interpretations of the terms that are used in the NERC standards that are not already addressed by NERC.

Combined Cycle Power Plant Module: A **combined cycle** is an assembly of heat engines that work in tandem off the same source of heat, converting it into mechanical energy, which in turn usually drives electrical generators. In a combined cycle power plant (CCPP), or combined cycle gas turbine (CCGT) plant, one or more gas turbine generator(s) generates electricity and heat in the exhaust is used to make steam, which in turn drives a steam turbine to generate additional electricity.

Entity Responsible for the Reliability of the Interconnected System Performance: In the operation of the grid, the ISO has primary responsibility for reliability. In the planning of the grid, reliability is a joint responsibility between the PTO and the ISO subject to appropriate coordination and review with the relevant local, state, regional and federal regulatory authorities.

Entity Required to Develop Load Models: The PTOs, in coordination with the utility distribution companies (UDCs) and others, develop load models.

Entity Required to Develop Load Forecast: The California Energy Commission (CEC) has the main responsibility for providing load forecast. If load forecast is not provided by the CEC or is not detailed and/or specific enough for a certain study then the ISO, at its sole discretion, may use load forecasts developed by the PTOs in coordination with the UDCs and others.

Footnote 12 of TPL-001-4 Interpretation and Applicable Timeline⁹: The shedding of Non-Consequential load following P1, P2-1 and P3 contingencies on the Bulk Electric System of the ISO Controlled Grid is not considered appropriate in meeting the performance requirements. In the near-term planning horizon the requirements of Footnote 12 may be applied until the long-term mitigation plans are

⁹Implementation and applicable timeline will remain the same as the "Effective Date:"(s) described in the NERC TPL-001-4 standard.

in-service. In the near-term transmission planning horizon, the non-consequential load loss will be limited to 75 MW and has to meet the conditions specified in Attachment 1 of TPL-001-4.

High Density Urban Load Area: Is an Urbanized Area, as defined by the US Census Bureau¹⁰ with a population over one million persons.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. For studies that address regional transmission facilities such as the design of major interties, a 1 in 5-year extreme weather load level should be assumed. For studies that are addressing local load serving concerns, the studies should assume a 1 in 10-year extreme weather load level. The more stringent requirement for local areas is necessary because fewer options exist during actual operation to mitigate performance concerns. In addition, due to diversity in load, there is more certainty in a regional load forecast than in the local area load forecast. Having a more stringent standard for local areas will help minimize the potential for interruption of end-use customers.

Planned or Controlled Interruption: Load interruptions can be either automatic or through operator action as long as the specific actions that need to be taken, including the magnitude of load interrupted, are identified and corresponding operating procedures are in place when required.

Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should be less than 30 minutes.

¹⁰ Urbanized Area (UA): A statistical geographic entity consisting of a densely settled core created from census tracts or blocks and contiguous qualifying territory that together have a minimum population of at least 50,000 persons.