BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for the Commission's Transmission Assessment Process	R.04-01-026

INITIAL COMMENTS AND SUBMISSION OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION IN RESPONSE TO ORDER INSTITUTING RULEMAKING

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

California Statutes

Others

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Pursuant to the Order Instituting Rulemaking, filed January 22, 2004 ("OIR"), and Rule 14.5 of the Commission's Rules of Practice and Procedure, the California Independent System Operator Corporation ("CAISO") respectfully responds to the Commission's request that the CAISO submit standards for determining whether a transmission project is required to maintain or enhance system reliability and comment on the proposed addition to General Order 131-D ("G.O. 131-D").[1] In doing so, the CAISO commends the Commission for initiating this Rulemaking and confirms its commitment to work cooperatively with the Commission and all interested parties to achieve the goal of this proceeding to improve the transmission planning and siting process in California. The CAISO strongly supports such an objective and outcome as a necessary means to ensure that needed transmission infrastructure gets planned, sited, and built in California.

1 See, OIR, Ordering ¶ 7 at p. 16.

I.

INTRODUCTION AND SUMMARY

The OIR properly recognizes that transmission planning and siting in California suffers unnecessarily from regulatory redundancy. The goal of this Rulemaking is "to streamline the transmission planning process for … [Investor Owned Utilities ("IOUs")] by eliminat[ing] duplicative transmission need assessments that currently exist at the CAISO and the Commission."[2] The Commission proposes to realize its goal of a more efficient transmission review process by amending G.O. 131-D, Section III.A.

The proposed amendment eliminates regulatory redundancy by creating a framework that allows the Commission to defer, in the context of an application for a certificate of public convenience and necessity ("CPCN"), to the prior determination of project need reached by the CAISO in its Grid Coordinated Planning Process. The OIR clarifies that the Commission's proposed deference will extend to CAISO need determinations for both reliability and economic projects to the extent the CAISO applies Commission-adopted standards.[3] Specifically, once economic and reliability methodologies are adopted by the Commission, the Commission's

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[2] OIR at pp. 1 and 5. Under Public Utilities Code section 1001, IOUs must secure from the Commission a certificate of public convenience and necessity as a precondition to constructing or expanding certain electrical transmission lines. The Commission has traditionally interpreted section 1001 as imposing an obligation to evaluate the proposed transmission project on the grounds of need, utility capital structure and cost impacts, ratepayer impacts, and environmental impacts as required by the California Environmental Quality Act. (OIR at p. 2.) However, in the current regulatory environment, the need for a particular project has already been evaluated prior to the CPCN application in the CAISO's Grid Coordinated Planning Process pursuant to the CAISO's statutory responsibility to ensure the efficient use and reliable operation of the transmission grid. (*Id.,* citing Pub. Util. Code § 345.)

[3] The CAISO understands that the absence of any prior submission from the CAISO in this proceeding or in any previous proceeding regarding its reliability methodology (i.e., the standards or policies applied by the CAISO to determine if a project is needed to support continued reliable operation of the grid) constituted the justification for the omission of any reference to "reliability" in proposed G.O. 131-D. As set forth below, the CAISO believes G.O. 131-D should be modified to include an explicit reference to a reliability methodology. The economic methodology referred to in the proposed amendment is currently being developed in the Commission's pending Transmission Investigation docket, I.00-11-001 and, therefore, is not the focus of this Rulemaking and the CAISO does not directly address it here.

review of a particular project's need determination during the CPCN proceeding would be limited to confirming that the adopted methodologies were applied by the CAISO.[4] Under this construct, the Commission would continue to conduct an environmental review of the proposed project under California Environmental Quality Act ("CEQA") through the CPCN proceeding.[5]

The OIR directs the CAISO to submit "standards" for use in determining whether a transmission project is required to maintain or enhance system reliability. In compliance with this directive, the CAISO submits its reliability methodology consisting of two basic components: (1) Applicable Reliability Criteria and (2) CAISO Grid Coordinated Planning Process. The Applicable Reliability Criteria are, in turn, composed of the reliability standards established for the bulk electric system in North America by the North American Electric Reliability Council ("NERC"), those established for the Western Interconnection by the Western Electricity Coordinating Council ("WECC"), and those established for the CAISO Controlled Grid by the CAISO Governing Board.[6] Although each of these components of the Applicable Reliability Criteria build-off one another to ensure consistent application across the NERC/WECC/CAISO regions, they are dynamic in nature and can be modified to meet changing needs by the respective governing bodies of NERC, WECC, and the CAISO. The CAISO's Grid Coordinated Planning Process is set forth in the CAISO Tariff at sections 3.2 et seq. and 5.7 et seq., Grid Coordinated Planning Process memorandum, and Grid Project Review Information Requirements.[7]

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[4] OIR at pp. 5, 8.

[5] OIR at p. 8.

[6] The NERC/WECC standards and CAISO Planning Standards, both discussed in further detail below, are attached as Exhibits 1 and 2, respectively.

[7] These documents, also discussed further below, are attached as Exhibits 3, 4, and 5, respectively.

With respect to the proposed changes to G.O. 131-D, the CAISO commends the creativity and candidness of the Commission and its underlying Staff Report[8] and concurs that the general framework outlined in the OIR will result in a more effective approach to transmission planning and siting by maximizing the respective expertise of the Commission and CAISO to the benefit of California's consumers. Specifically, the CAISO supports the Commission's vision of funneling the resource mix determinations from the IOU's long-term procurement plans into the CAISO Grid Coordinated Planning Process. By incorporating the Commission's resource decisions involving generation, distributed generation, and demand-side management – which of course are based on, among other factors, load forecast assumptions - into the CAISO's planning process, the IOUs, CAISO, and stakeholders need not revisit these issues in the planning process and the Commission can properly defer to the load and supply forecast assumptions when it reaffirms the CAISO's need determinations in the CPCN process. The CAISO acknowledges, of course, that the Commission will have to ensure that the timing of these processes (i.e., procurement, transmission planning, and CPCN) is such that important inputs, such as load forecasts, do not become stale.

Nevertheless, the CAISO believes changes to the proposed language are necessary to clarify authority, remove ambiguity, and ensure regulatory efficiency:

1. Add a reference to a "reliability" methodology to correct for its omission.
2. Clarify that the Commission is only confirming whether the CAISO applied the economic and reliability needs assessment standards and methodologies adopted by the Commission.

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[8] As noted, the CAISO also commends Commission staff for its thoughtful and comprehensive analysis set forth in the Report on the Current Transmission Planning Process for Investor Owned Utilities ("Staff Report") attached as Appendix B to the OIR.

3. Ensure that the proposed streamlined planning and siting process accommodates the necessarily and appropriately subjective nature of the CAISO's proposed reliability methodology. That is, the Commission should acknowledge and its rules should accommodate the fact that reliability criteria and standards necessarily evolve over time and are, by nature, subjective.

Accordingly, to address the three identified concerns, the CAISO recommends amending proposed G.O. 131-D in the following manner (modifications underlined):

> The Commission will utilize the CAISO's determination of whether a transmission facility is required for reliability or for economic reasons to the extent it has analyzed the need for the proposed transmission facility using the Commission-adopted reliability or economic methodology, as those methodologies may be amended from time to time in accordance with the applicable rules and procedures of NERC, WECC, and/or the CAISO. Once the transmission facility is before the Commission for a CPCN, the Commission will determine whether the CAISO applied the adopted reliability or economic methodology to the project, without revisiting the question of need. The Commission will implement this provision consistent with PU Code 1822 and CPUC Rules of Practice and Procedure Article 17.1.

II.

DESCRIPTION OF CAISO'S PROPOSED RELIABILITY STANDARDS

A. Applicable Reliability Criteria

Public Utilities Code section 345 provides that, "the [CAISO] shall ensure efficient use and reliable operation of the transmission grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council." To satisfy that obligation, the CAISO adheres to both established *operating* reserve criteria (e.g., established WECC Operating Reserve requirements) and established *planning* standards, as described below. Each of these sets of standards or requirements is designed to not only meet demand under normal operating conditions, but must also meet demand under various criteria that assume outages of various components of the system. To satisfy these objectives and in order to comply with Public Utilities Code section 345, the CAISO adopted reliability criteria comprised of three parts:

1. The NERC planning standards (Exhibit 1);
2. The WECC planning standards (successor to the Western Systems Coordinating Council) (Exhibit 1); and
3. The CAISO planning standards (Exhibit 2).

The CAISO Tariff further specifies that the CAISO and Participating Transmission Owners ("PTOs") must ensure system reliability consistent with Applicable Reliability Criteria.[9] Applicable Reliability Criteria is defined as "the reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the [Nuclear Regulatory Commission]." The NERC planning standards apply to all NERC Regional Councils, who geographically cover the continental United States, several Canadian provinces, and the northern portion of Baja California Norte, Mexico. The universal application of the NERC standards follows from reliance on multiple entities to ensure reliability of the interconnected bulk electricity system. In an integrated network, the performance of one system can affect the performance of other systems, thereby impacting the ability of these systems to meet reliability criteria. Accordingly, the NERC reliability criteria set specific planning standard performance requirements that must be satisfied by all Reliability Councils within the NERC organization. Similarly, the NERC Reliability Councils, such as the WECC, have the responsibility of coordinating the application of the NERC standards within their council region

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9 CAISO Tariff § 3.2.1.2 (Exhibit 3).

as well as of developing and applying standards that incorporate the NERC standards, but reflect the characteristics, geography, and demographics of the particular Reliability Council. Both NERC and the WECC have transparent and formalized procedures to adopt, change, or remove planning standards and it is common for such standards to be modified periodically as experience and technological innovations dictate.

Like the WECC, the CAISO develops and applies additional standards that incorporate and are based on NERC and WECC standards, but reflect the characteristics, geography, and demographics of its Control Area. Specifically, the CAISO planning standards are intended to supplement the NERC/WECC general standards by addressing reliability issues specific to the CAISO Controlled Grid. The CAISO's intent is to build off of, to the extent possible, the regional (WECC) and continental (NERC) standards in recognition of the need to coordinate the development (i.e., expansion) of the CAISO grid with neighboring non-CAISO electric systems inside and outside California. The CAISO Grid Planning Standards are developed through a stakeholder process and implemented following approval by the CAISO Board of Governors.

In general, the CAISO's Applicable Planning Criteria are designed to ensure reliable system performance under "likely" events or contingencies (e.g., the loss of a single element, e.g., transmission line or generating unit) and provide allowances for less optimal system performance under "unlikely" events (e.g., the loss of multiple elements). Nevertheless, the NERC/WECC/CAISO planning standards are deterministic, not probabilistic. This means that the NERC/WECC/CAISO planning standards set forth fixed boundaries that limit the extent or scope of allowable system performance resulting from expected events that occur on the power system. (See Exhibit 2 at p. 9.) The planning standards are defined by allowable system performance levels (A, B, C, or D) that result from a specific system element or multiple elements being forced out of service by some unknown event.

As an example on how to read the criteria, refer to Table I, page 25, of the combined NERC/WECC standards (Exhibit 1). NERC/WECC system performance Category B identifies the acceptable system performance measurements that must be met if the loss of a single transmission element occurs. In this particular example, a single-line-to-ground fault could result in the loss of a generator, a transformer, or a transmission line. The allowed system performance for this event is described as: "All other transmission elements within applicable ratings, all voltages within applicable ratings, the system is stable, no loss of customer load is allowed and no cascading is allowed." Table W-1 on page 12 adds the more stringent WECC requirements, "Transient voltage swings are not allowed to exceed 25% at load busses and 30% at non-load busses, frequency deviations should not go below 59.6 Hz for 6 cycles, and post-transient voltage dips should not exceed 5% at any bus." By way of this example, it should be clear that the NERC, WECC, and CAISO standards are interrelated and build upon each other to create an appropriate standard for measuring the reliability of the CAISO grid.

B. CAISO Coordinated Grid Planning Process

Under the Federal Energy Regulatory Commission ("FERC") approved CAISO Tariff, the CAISO is required, in coordination with PTOs, to identify the need for any transmission additions or upgrades required to ensure that their system's performance is consistent with Applicable Reliability Criteria.[10] To meet this requirement, PTOs annually file a transmission expansion plan for their service territory that documents how they propose to satisfy the Applicable Reliability Criteria. Violations of Applicable Reliability Criteria generally have three

[10] CAISO Tariff § 3.2.1.2 (Exhibit 3).

potential categories of solutions: new generation, new transmission and/or load reduction. Accordingly, while the annual plans are intended to identify and select transmission solutions to reliability violations, information on generation and other operating solutions, including demand-side management and remedial action schemes, are also included to permit the prudent and reasoned evaluation of the merits of PTO-proposed transmission projects.[11] The PTO transmission expansion plan provides a detailed, year-by-year analysis of projects needed to meet reliability criteria for the next five years, plus an analysis of the tenth year.[12] The first five-year analysis is necessary to fit with the PTOs' budgeting cycles. The tenth-year analysis is required to facilitate identification of longer-term transmission needs not identified in the initial five-year assessment, including projects with permitting and construction timeframes greater than five years, and the integration of short-term transmission needs into longer planning requirements (e.g., to avoid building three 230kV lines when a single 500kV line would be more efficient). Because the PTOs' transmission plans are performed on an annual basis, they demonstrate a rolling ten-year planning horizon for their systems.

Subsequent to the submission of each PTO's annual plan, and for purposes of developing a CAISO Controlled Grid-wide integrated plan, the CAISO then initiates an open stakeholder process in February of the calendar year to ensure stakeholders are provided an early opportunity to review and comment on the transmission expansion plans submitted by the PTOs. The product of this stakeholder participation is the development of base cases and study plans. The study plans are required to incorporate concerns identified by stakeholders and describe how

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11 CAISO Tariff § 3.2.1 (Exhibit 3); Exhibit 4 at pp. 1 and 7.

12 CAISO Tariff § 3.2.2.1. (Exhibit 3)

those concerns will be addressed in the study.[13] For purposes of stakeholder notification of the initiation of the annual transmission planning process, the CAISO publishes a market notice that is disseminated to all stakeholders listed on the CAISO's "Market Participant" e-mail list. The "Market Participant" e-mail list is maintained and constantly updated by the CAISO's client relations department. Any entity or individual interested in CAISO activities may have their name placed on the list. Accordingly, the CAISO appropriately relies on this "Market Participant" e-mail list and public awareness for participation in the stakeholder process.

Following initial stakeholder input, the PTOs further refine identified analyses of their individual systems, hold additional meetings as needed with the CAISO and stakeholders, and coordinate with the CAISO on the development, execution, and evaluation of the studies. Toward the end of the calendar year, the PTOs hold a final open stakeholder meeting to discuss the results of the studies and to address all remaining comments on the studies. Subsequent to this meeting, a study report is finalized and submitted to the CAISO for its final approval. In its review, the CAISO considers numerous detailed factors, as set forth in Exhibit 5, to evaluate the transmission projects set forth in the PTO's transmission plan, including, but not limited to:

1. A description of the proposed project – length of line, supporting structure type, substation bus arrangements, general routing information, line rating, shunt capacitor sizes, etc.;
2. Cost estimates – equipment and land costs, description of justifications for variations from typical costs;
3. Project schedule;
4. Key issues, including land use restrictions and environmental concerns;

13 See, Exhibit 4.

5. Background – identify nature of violation of Applicable Reliability Criteria, provide load forecast, rationale for selecting the identified project as the preferred project;

6. Base case assumptions – identify other projects that may affect study results, load modeling assumptions, generation assumptions, etc.;

7. Other study assumptions – including the computer models used in the study;

8. Documentation of studies – provide power flow, post-transient load flow and stability analyses, sensitivities, etc.; and

9. Project alternatives – list of transmission alternatives considered and explanation of why they were not selected.

By using the above criteria the CAISO can ensure all reliability criteria violations have been appropriately identified and addressed, reasonable transmission alternatives considered, and the recommended project comprehensively evaluated. Once the CAISO has approved the PTOs' transmission expansion plans, their recommended projects are incorporated into the CAISO's Controlled Grid Study to corroborate that all reliability violations have been addressed and to assure that there are no "seams" issues among the PTOs' systems that were not identified in the PTOs' individual studies. After the CAISO finishes this analysis, projects deemed needed and which cost in excess of $20 million are submitted to the CAISO Board of Governors for their approval. CAISO management approves needed projects that cost under $20 million. Subsequently, to the extent necessary under G.O. 131-D, the PTOs file applications with the Commission for a CPCN.

In separate processes, but still part of the overall CAISO Coordinated Grid Planning Process, the CAISO Grid Planning Department performs studies to determine Reliability Must-Run (RMR) requirements for local areas and reviews and approves the PTO studies for new generator interconnection projects. These additional studies are conducted to determine the need for additional transmission projects or the modification of projects identified during the annual grid planning process. RMR requirements are determined by a subset of the CAISO Planning Standards called the "CAISO Reliability-Must-Run Criteria."[14] [15]

III.

CAISO'S COMMENTS ON AMENDMENT TO G.O. 131-D

A. The Amendment to G.O. 131-D Should Explicitly Include the CAISO's Reliability Methodology.

The proposed amendment to G.O. 131-D set forth in the OIR fails to reference adoption by the Commission of a methodology for determining transmission project need based on system reliability or any subsequent deference to that need determination by the CAISO. The OIR makes clear, however, that the Commission's proposed deference will extend to CAISO need determinations for reliability projects to the extent the CAISO applies Commission-approved standards. As noted in the OIR, the recommended approach would eliminate existing redundancy in transmission need assessment "by having the CAISO responsible for assessing

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14 Attached as Exhibit 6.

15 In addition, until recently, the CAISO Coordinated Planning Process has not assessed the deliverability of generation for the purposes of resource adequacy. Pursuant to the Federal Energy Regulatory Commission's direction in its order regarding standardization of generation interconnection agreements and procedures ("Order No. 2003") the CAISO recently filed Standard Large Generator Interconnection Procedures with FERC ("LGIP"). The CAISO included a new Deliverability Assessment in the LGIP to establish that each Load Serving Entity demonstrate, pursuant to defined standards and under a given set of system conditions, that the resources they have procured can be delivered to satisfy system aggregate load, and that local transmission constrained areas have sufficient transmission and generation resources to ensure that available generation resources located outside the local area can be adequately delivered to the local load. The CAISO encourages the Commission and the California Energy Commission to participate in the development of the details of this Deliverability Assessment methodology.

whether a project is needed for reliability and economic reasons."[16] The CAISO understands that the Commission felt procedurally compelled to omit reference to reliability standards in the proposed amendment until the CAISO submitted its reliability standards proposal for Commission consideration. Of course, upon adoption by the Commission of reliability standards, the CAISO believes this omission should be corrected to appropriately permit deference to CAISO need determinations based on reliability reasons.

B. The Commission Can Appropriately Defer to the Need Determination Reached Through the CAISO's Grid Coordinated Planning Process.

The Commission has historically determined in CPCN proceedings whether transmission infrastructure is needed to meet a reliability requirement by comparing the performance or capacity of the existing power system to the performance or capacity of the power system modified by inclusion of the proposed project identified in the CAISO's grid planning process.[17] The performance of both the existing power system and the modified power system is evaluated under the same set of prescribed outage contingencies and over an appropriate planning horizon that assumes some reasonable demand and supply forecasts. It follows, therefore, that in order to achieve the efficiency intended by this OIR by deferring to CAISO need determinations on reliability grounds, the reliability methodology used by the CAISO, and adopted by the Commission, must similarly apply (1) reliability criteria, (2) planning horizon, (3) load forecasts, and (4) supply forecasts. The CAISO's standards and processes, in conjunction with the

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16 OIR at p. 8.

17 See, *In the matter of Application of Pacific Gas and Electric Company (U 39 E) for a Certificate of Public Convenience and Necessity Authorizing Construction of the Tri-Valley 2002 Capacity Increase Project,* D.01-10-029 (Oct. 11, 2001); *In the matter of Application of Pacific Gas and Electric Company (U 39 E) for a Certificate of Public Convenience and Necessity for the North East San Jose Transmission Reinforcement Project,* D.01-05-059 (April 17, 2001); and *In the Matter of the Application of San Diego Gas & Electric Company (U 902 –E) for Certificate of Public Convenience and Necessity Valley-Rainbow 500kV Inter-Connect Project,* D.02-12-066 (Dec. 24, 2002) ("Valley-Rainbow Decision").

Commission's proposed framework for implementing amended G.O. 131-D, and as complemented by the Commission's established integrated planning or IOU procurement process, will appropriately address each of these components.

1. Applicable Reliability Criteria

The CAISO's Applicable Reliability Criteria, as described above and as set forth in attached Exhibits, appropriately defines performance standards that must be attained by the transmission grid and should be adopted by the Commission for purposes of furthering the stated objective of the OIR.

2. Planning Horizon

The OIR expressly states "that by deferring to the CAISO's determination of need, the Commission must necessarily accept the CAISO planning horizon, which is ten years. This longer-term outlook would replace the five-year time horizon that the Commission has typically used to assess when and whether a project is needed."[18] The CAISO applauds the Commission's flexibility and notes that the OIR does not represent a radical departure from Commission precedent. The Commission has acknowledged that a "planning horizon should not be mechanistically applied but rather requires an exercise of judgment based on the facts of each project."[19] For complex projects of the type likely to trigger a CPCN requirement, the ten-year planning horizon better corresponds to the lead-time in planning, permitting, and constructing large high voltage transmission projects. Indeed, adopting a longer planning horizon will likely encourage flexibility and creativity in meeting identified transmission infrastructure needs by

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18 OIR at p. 8.

19 Valley-Rainbow at p. 17.

permitting IOUs to propose long lead-time facilities rather than potentially piece-meal solutions that satisfy a shorter planning perspective.

3. Load Forecast

The applicable load forecast can constitute a source of controversy in CPCN proceedings because the determination regarding whether reliability standards are satisfied is highly dependent on the load forecast being used. Prudent transmission planning practice utilized throughout the WECC interconnected system considers a load forecast that reflects system conditions that would result in reasonably high electricity usage. As such, the CAISO Planning Standards require that transmission planning studies be conducted using a 1-in-10 year adverse whether condition to ensure that reliable service can be maintained even under stressed system conditions. Within this general parameter, however, the CAISO currently relies on the detailed forecasts prepared by the PTOs for purposes of developing their annual transmission plans. The PTO's forecasts are subject to stakeholder review and comment. In addition, the CAISO checks the reasonableness of the PTO forecasts against forecast data produced by the California Energy Commission ("CEC") and the CAISO's own load forecasts.

Reliance on the PTOs' load forecasts, as developed in the stakeholder process and independently validated by the CAISO, reflects an efficient and accurate approach to modeling future load. The PTOs generally possess the most detailed data regarding the effect of variable weather conditions and demand efficiency and conservation programs on regional, subregional, and highly localized load levels that are key components in developing load information at the highly granular levels necessary to run technical assessments. This approach has proven to be effective and accurate in producing load forecasts for planning purposes.

The OIR recognizes that adopting this process satisfies the Commission's view of its responsibilities under Public Utilities Commission Code section 1001. It does so through the integration of the Commission's IOU long-term procurement plans with the CAISO Grid Coordinated Planning Process.

> Once the Commission determines that transmission is needed after balancing competing options such as generation and demand side alternatives, that determination would be reflected in the CAISO's planning process, where a detailed analysis occurs for specific transmission projects. The Commission's upfront determination on transmission need in the procurement process would accomplish two objectives: 1) a comprehensive analysis of the alternatives available to meet customer resource requirements; and 2) an upfront determination that transmission is needed and fits within the comprehensive infrastructure plan that can be recognized once a specific project has been developed in the CAISO planning process and, if required, is before the Commission for CPCN.[20]

The Commission, therefore, appropriately acknowledges that its long-term clarification of the IOUs' desired resource mix will permit a reasonable assessment of the anticipated effects of conservation, energy efficiency, and demand-side management programs in the context of the CAISO's Grid Coordinated Planning Process.[21] Thus, the only question that would have to be considered at the CPCN proceeding to justify Commission deference is whether the load forecast assumptions generated by the CAISO's Grid Coordinated Planning Process incorporate the Commission's comprehensive infrastructure planning analysis from the approved IOU procurement plans.

4. Supply Forecast

For any given project area, the supply forecast generally involves an assessment of existing supply resources, both local generation and import transmission facilities, and an

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[20] OIR at p. 7.

[21] In addition, any assessment of the "deliverability" of IOU resources in the context of the Commission's procurement rules may also have a direct affect on the inputs to and outcome of the CAISO's Grid Planning Process.

estimate of future additions to supply resources. The Commission has limited inclusion of proposed generation resources in five-year planning cases to those which are "under construction or have received regulatory permits in the resource mix for transmission planning purposes unless there is compelling evidence that the future of such plants is in question."[22] The Commission's approach is consistent with that developed by the CAISO Planning Standard's Committee for a ten-year planning horizon.[23] The CAISO developed five stages of generation development for the modeling of new generation in the initial power flow cases used to assess the need for transmission system additions:

Level 1: Under Construction

Level 2: Regulatory Approval

Level 3: Application Under Review

Level 4: Starting Application Process

Level 5: Press Release Only

For ten-year planning cases, the CAISO's standards provide that only generation that is under construction or has received regulatory approval (Levels 1 and 2) 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 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. This bright-line test can be augmented by the outcome of the procurement proceeding to remove forecast assumption uncertainty in the same manner as described for load forecasting.

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22 Valley-Rainbow at 33.

23 "California ISO Approach on the Modeling of New Generation in Powerflow Cases," attached as Exhibit 7.

Similarly, information from the procurement proceedings could provide significant guidance for generation retirement assumptions (i.e. generation with long-term contracts is much less likely to retire than generation without long-term contracts). The sole question, therefore, for the Commission to resolve at the CPCN proceeding is again whether the resource determinations in the IOU procurement plans were utilized in the CAISO's Grid Coordinated Planning Process.

C. An Expedited Mechanism Must Be Crafted To Allow "Adoption" of Changes to the CAISO's Applicable Reliability Criteria

The OIR states that "[t]he Commission believes that by adopting an economic methodology that the CAISO and IOUs will apply to transmission projects, the Commission would be fulfilling its statutory mandate under Section 1001, which places on the Commission the responsibility to determine that a utility project is needed."[24] Similarly, the proposed amendment to G.O. 131-D expressly provides that the Commission's deference is limited "to the extent that the CAISO has analyzed the need for the proposed transmission facility using a Commission-adopted economic methodology." The CAISO interprets the language used by the Commission as not attempting to enlarge its authority by somehow requiring Commission "approval" of either the economic or reliability methodologies applied by the CAISO, but merely that for purposes of its CPCN process the methodologies must be formally adopted or recognized by the Commission to permit deference.[25] Nevertheless, the CAISO is concerned that the

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[24] OIR at p. 9.

[25] The CAISO has repeatedly asserted in various Commission proceedings that the Commission is legally obligated to defer to the CAISO's need determination regardless of whether or not particular reliability or economic methodologies are adopted by the Commission. The CAISO does not waive its position. However, rather than fully reiterate in its comments the basis for this assertion, the CAISO hereby incorporates by reference its "Opening Brief of the California System Operator," filed in Conditional Application of SAN DIEGO GAS AND ELECTRIC COMPANY for a Certificate of Public Convenience and Necessity Authorizing the Construction of the Valley-Rainbow 500 kV Transmission Project, A.01-03-036, on July 12, 2002. Moreover, the CAISO believes that this

expected advantages of the proposed streamlined planning process will evaporate if a cumbersome or static "adoption" requirement is unable to accommodate the evolving nature of the Applicable Reliability Criteria and economic methodology.

As noted above, the CAISO is compelled by both state and federal law to apply the NERC/WECC standards. These entities can and are continuously contemplating modification to their standards especially after the August 14, 2003 Northeast blackout. When promulgated, changes to the NERC/WECC standards are automatically incorporated into the Applicable Reliability Criteria. Similarly, Public Utilities Code section 345's mandate that the CAISO "ensure efficient use and reliable operation of the transmission grid" imposes on the CAISO an independent obligation to ensure a reliable and cost-effective transmission system. This authority further arises from the FERC's directive that the CAISO coordinate transmission planning, and subsequent FERC determinations approving the transmission planning section of the CAISO's tariff that includes the responsibility to determine whether a transmission project is needed to promote economic efficiency or reliability. (See e.g. 81 FERC ¶ 61,122, pp 61,459 (October 30, 1997); 80 FERC ¶ 61,128, pp 61,430-35 (July 30, 1997); CAISO Tariff § 3.2.1.) Accordingly, the CAISO possesses not only the authority, but obligation, to amend its Grid Planning Standards and Grid Coordinated Planning Process, from time to time to meet its statutory responsibilities.

The CAISO believes that reopening this Rulemaking proceeding, or amending G.O. 131-D, upon every change in either the Applicable Reliability Criteria or Grid Coordinated Planning Process would defeat the regulatory efficiency envisioned by the OIR. The CAISO appreciates the Commission's interpretation of its statutory responsibility under Public Utilities Code section

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Rulemaking can accommodate the views and needs of the CAISO, Commission, and market participants and, therefore, is pleased to work with the Commission to achieve a mutually acceptable outcome.

1001 and is willing to seek a creative solution to the identified problem. As noted above in the introduction, the CAISO believes that the most efficient solution consistent with the goal of this Rulemaking, is to modify G.O. 131-D in a manner that specifies that the Commission will defer to a CAISO need determination based on the approved standards as they may be amended from time to time by the entities with authority to make such amendments. In this regard, it should be noted that the Commission is a WECC member and may participate in the formulation of regional reliability standards. Similarly, the Commission's Staff Report recommends as one of its five main recommendations that the Commission become more active in the CAISO planning process.[26] The CAISO strongly encourages Commission participation in its Grid Planning Standards Committee to provide needed input into the standards applied by the CAISO.

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[26] OIR, Appendix B at p. 2.

IV.

CONCLUSION

The CAISO believes that the Commission should proceed and adopt the proposed changes to G.O. 131-D as modified by the CAISO above. The CAISO further believes that the Commission can fulfill its statutory obligation under Public Utilities Code section 1001 to determine need in the context of a CPCN application by adopting the Applicable Reliability Criteria as well as the process reflected in the Grid Coordinated Planning Process.

Respectfully submitted,

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Attorneys for
California Independent System Operator

Dated: February 23, 2004

CERTIFICATE OF SERVICE

I hereby certify that at the time of submission of **COMMENTS AND SUBMISSION OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION IN RESPONSE TO ORDER INITIATING RULEMAKING in Docket #R.04-01-026**, the California Public Utilities Commission had not yet established an official service list in accordance to the procedures set forth in the Order Instituting Rulemaking issued on January 28, 2004.

Executed on February 23, 2004, at Folsom, California.

Charity N. Wilson
An Employee of The California
Independent System Operator

VERIFICATION

Pursuant to Rules 14.5 and 2.4 of the Commission's Rules of Practice and Procedure, I, Armando Perez, hereby verify the factual assertions set forth in the California Independent System Operator's ("CAISO") Initial Comments and Submission filed on February 23, 2004, in R.04-01-026 ("Initial Comments"). I am Director of Grid Planning for the CAISO and am familiar with the standards, policies and procedures referenced by the CAISO in the Initial Comments. I have reviewed the CAISO's Initial Comments, and to the best of my knowledge, the facts included therein are true and correct.

I declare under penalty of perjury that the foregoing is true and correct.

Armando S. Perez

Armando Perez

Signed February 23, 2004, in Folsom, California

EXHIBIT 1

Western Electricity Coordinating Council

RELIABILITY CRITERIA

PART I - NERC/WECC PLANNING STANDARDS

PART II - POWER SUPPLY ASSESSMENT POLICY

PART III - MINIMUM OPERATING RELIABILITY CRITERIA

PART IV - DEFINITIONS

PART V - PROCESS FOR DEVELOPING AND APPROVING WECC STANDARDS

AUGUST 2002

Western Electricity Coordinating Council

AUGUST 2002

RELIABILITY CRITERIA

PART I - NERC/WECC PLANNING STANDARDS

PART II - POWER SUPPLY ASSESSMENT POLICY

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PART V - PROCESS FOR DEVELOPING AND APPROVING WECC STANDARDS

The WECC Reliability Criteria set forth the performance standards used by Western Electricity Coordinating Council and its Member Systems in assessing the reliability of the interconnected system. During 1996 the Council initiated an in-depth and comprehensive review of these Criteria. Recommendations made as a result of this review have been adopted by the Council and these Criteria have been revised accordingly. Definitions for key words and phrases used in the Council's planning and operating criteria are included.

WESTERN ELECTRICITY COORDINATING COUNCIL

NERC/WECC PLANNING STANDARDS

PART I

Contents

Preface

This document merges the WECC Planning Standards into the ***NERC Planning Standards****. The WECC Planning Standards are indicated in italic and are preceded by headings WECC-S, WECC-M, or WECC-G, depending upon whether the differences are Standards, Measures or Guides. Certain aspects of the WECC standards are either more stringent or more specific than the NERC standards.*

The NERC standards and associated Table I are applicable to all systems, without distinction between internal and external systems. Unless otherwise stated, WECC standards and the associated WECC Disturbance-Performance Table of Allowable Effects on Other Systems are not applicable to internal systems.

It is intended that the WECC standards be periodically reviewed by the Reliability Subcommittee as experience indicates, in accordance with WECC's Process for Developing and Approving WECC Standards.

Foreword

This **NERC Planning Standards** report is the result of the NERC Engineering Committee's efforts to address how NERC will carry out its reliability mission by establishing, measuring performance relative to, and ensuring compliance with **NERC Policies**, **Standards**, **Principles**, and **Guides**. From the planning or assessment perspective, this report establishes **Standards** and defines in terms of **Measurements** the required actions or system performance necessary to comply with the **Standards**. This report also provides **Guides** that describe good planning practices for consideration by all electric industry participants.

Mandatory compliance with the **NERC Planning Standards** is required of the NERC Regional Councils (Regions) and their members as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment. This report, however, does not address issues of implementation, compliance, and enforcement of the **Standards**. The timing and manner in which implementation and enforcement of and compliance with the **NERC Planning Standards** will be achieved has yet to be defined.

Background

At its September 1996 meeting, the NERC Board of Trustees unanimously accepted the report, *Future Course of NERC*, of its Future Role of NERC Task Force - II. This report outlines several findings and recommendations on NERC's future role and responsibilities in the light of the rapidly changing electric industry environment.

The report also concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In accepting the Task Force's report, the Board also directed the NERC Engineering Committee and Operating Committee to develop appropriate implementation plans to address the recommendations in the *Future Course of NERC* report and to present these plans to the Board at its January 1997 meeting. The primary focus of the action plans and the initiatives from the Engineering Committee perspective was the development of **Planning Standards and Guides**. At its January 1997 meeting, the NERC Board of Trustees accepted the Engineering Committee's November 1996 "Proposed Action Plan to Establish Revised and New NERC Planning Standards and Guides" report. This action plan formed the basis for the development of **NERC's Planning Standards**.

Standards Development

The Engineering Committee assigned the overall responsibility for the development and coordination of the **NERC Planning Standards** to its Reliability Criteria Subcommittee (RCS). The Engineering Committee's other subgroups were also called upon to provide major inputs to RCS in its **Planning Standards** development effort. These other subgroups included: the Reliability Assessment Subcommittee, the Interconnections Dynamics Working Group, the Multiregional Modeling Working Group, the System Dynamics Database Working Group, the Load Forecasting Working Group, and the Available Transfer Capability Implementation Working Group.

In the development of the **NERC Planning Standards**, all proposed **Standards, Measurements, and Guides** were distributed for Regional and electric industry review prior to their submittal to the Engineering Committee and Board for approval. The Engineering Committee recognized that the **NERC Planning Standards** would have to be more specific than in the past, and that differences among the Regions would still need to be considered. It also recognizes that the development of **Planning Standards** will be an evolutionary process with continual additions, changes, and deletions.

The Engineering Committee extends its appreciation to the members of its subgroups and the members of the Regions and electric industry sectors that commented on the proposed drafts of the **NERC Planning Standards** in their development phases. A substantial effort was expended to develop the **NERC Planning Standards** in a very short time frame.

Foreword

The **NERC Planning Standards** continue to define the reliability of the interconnected bulk electric systems using the following two terms:

- **Adequacy** - The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- **Security** - The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

The Engineering Committee recognizes that this **NERC Planning Standards** report is the first such industry effort to establish industry **Planning Standards** requiring mandatory compliance by the Regions, their members, and all other electric industry participants. This report also defines the specific actions or system performance that must be met to ensure compliance with the **Planning Standards**.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and their capability to support a wide variety of transfers.

The future challenge to the reliability of the electric systems will be to plan and operate transmission systems so as to provide requested electric power transfers while maintaining overall system reliability.

Introduction

Electric system reliability begins with planning. The **NERC Planning Standards** state the fundamental requirements for planning reliable interconnected bulk electric systems. The **Measurements** define the required actions or system performance necessary to comply with the **Standards**. The **Guides** describe good planning practices and considerations.

With open access to the transmission systems in connection with the new competitive electricity market, all electric industry participants must accept the responsibility to observe and comply with the **NERC Planning Standards** and to contribute to their development and continued improvement. That is, compliance with the **NERC Planning Standards** by the Regional Councils (Regions) and their members as well as all other electric industry participants is mandatory.

The Regions and their members along with all other electric industry participants are encouraged to consider and follow the **Guides**, which are based on the **NERC Planning Standards**. The application of **Guides** is expected to vary to match load conditions and individual system requirements and characteristics.

Background

In January 1996, the NERC Board of Trustees formed a task force to reassess NERC's future role, responsibilities, and organizational structure in light of the rapidly changing electric industry environment. The task force's report, *Future Course of NERC*, accepted by the Board at its September 1996 meeting, concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In January 1997, the Board voted unanimously to obligate its Regional and Affiliate Councils and their members to promote, support, and comply with all NERC Planning and Operating Policies.

Regional Planning Criteria and Guides

The Regions, subregions, power pools, and their members have the primary responsibility for the reliability of bulk electric supply in their respective areas. These entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria and guides that are based on the **Planning Standards** and which reflect the diversity of individual electric system characteristics, geography, and demographics for their areas.

Therefore, all electric industry participants must also adhere to applicable Regional, subregional, power pool, and individual member planning criteria and guides. In those cases where Regional, subregional, power pool, and individual member planning criteria and guides are more restrictive than the **NERC Planning Standards**, the more restrictive reliability criteria and guides must be observed.

Responsibilities for Planning Standards, Measurements, and Guides

The NERC Board of Trustees approves the **NERC Planning Standards, Measurements, and Guides** to ensure that the interconnected bulk electric systems are planned reliably.

To assist the Board, the NERC Engineering Committee:

- Develops the **NERC Planning Standards, Measurements, and Guides** for the Board's approval, and
- Coordinates the **NERC Planning Standards, Measurements, and Guides**, as appropriate, with corresponding Operating Policies, Standards, Measurements, and Guides developed by the NERC Operating Committee.

The Regions, subregions, power pools, and their members:

- Develop planning criteria and guides that are applicable to their respective areas and which are in compliance with the **NERC Planning Standards,**
- Coordinate their planning criteria and guides with neighboring Regions and areas, and
- Agree on planning criteria and guides to be used by intra- and interregional groups in their planning and assessment activities.

Format of the NERC Planning Standards

The presentation of the **Planning Standards** in this report is based on the following general format:

- **Introduction** - Background and reason(s) for the **Standard(s)**.
- **Standard** - Statement of the specifics requiring compliance.
- **Measurement** - Measure(s) of performance relative to the **Standard**.
- **Guides** - Good planning practices and considerations that may vary for local conditions.
- **Compliance and Enforcement** - Not addressed in this report.

Introduction

The **NERC Planning Standards** are in bold face type to distinguish them from the other sections of the report. In some cases, the **Measurements** of a Standard are multifaceted and address several characteristics of the bulk electric systems or system components.

Definition of Bulk Electric System

The **NERC Planning Standards, Measurements, and Guides** in this report are intended to apply primarily to the bulk electric systems, also referred to as the interconnected transmission systems or networks. Because of the individual character of each of the Regions, it is recommended that each Region define those facilities that are to be included as its bulk electric systems or interconnected transmission systems for which application of the **Planning Standards** will be required. Any differences from the following Board definition of bulk electric system shall be documented and reported to the NERC Engineering Committee prior to the application or implementation of the **Planning Standards** in this report.

The NERC Board of Trustees at its April 1995 meeting approved a definition for the bulk electric system as follows:

> **"The bulk electric system is a term commonly applied to that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher."**

This definition is included in the May 1995 NERC brochure on "Planning of the Bulk Electric Systems" prepared by a task force of the Engineering Committee.

A system facility, element, or component has been defined as any generating unit, transmission line, transformer, or piece of electrical equipment comprising an electric system. This definition is included in the May 1995 NERC *Transmission Transfer Capability* reference document.

Compliance With NERC Planning Standards

The interconnected bulk electric systems in the United States, Canada, and the northern portion of Baja California, Mexico are comprised of many individual systems, each with its own electrical characteristics, set of customers, and geographic, weather, and economic conditions, and regulatory and political climates. By their very nature, the bulk electric systems involve multiple parties. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the reliability of the other systems. Therefore, to maintain the reliability of the bulk electric systems or interconnected transmission systems or networks, the Regions and their members and all electric industry participants must comply with the **NERC Planning Standards**.

The interconnected transmission systems are the principal media for achieving reliable electric supply. They tie together the major electric system facilities, generation resources, and customer demand centers. These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:

- **Deliver Electric Power to Areas of Customer Demand** - Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions.

- **Provide Flexibility for Changing System Conditions** - Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.

- **Reduce Installed Generating Capacity** - Transmission interconnections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing investment in generation facilities.

- **Allow Economic Exchange of Electric Power Among Systems** - Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among all systems and industry participants. Such economy transfers help to reduce the cost of electric supply to customers.

Electric power transfers have a significant effect on the reliability of the interconnected transmission systems, and must be evaluated in the context of the other functions performed by these interconnected systems. In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned, and as opposition to new transmission prevents facilities from being constructed as planned. Efforts by all industry participants to minimize costs will also continue to encourage, within safety and reliability limits, maximum loadings on the existing transmission systems.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will be to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability.

All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk electric systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Adequacy and Security (I.) are provided in the following sections:

A. Transmission Systems
B. Reliability Assessment
C. Facility Connection Requirements
D. Voltage Support and Reactive Power
E. Transfer Capability
F. Disturbance Monitoring

Introduction

The fundamental purpose of the interconnected transmission systems is to move electric power from areas of generation to areas of customer demand (load). These systems should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and planned equipment outages, continuously varying customer demands) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.

Electric systems must be planned to withstand the more probable forced and planned outage system contingencies at projected customer demand and projected electricity transfer levels.

Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. The risks and consequences of these contingencies should be reviewed by the entities responsible for the reliability of the interconnected transmission systems. Actions to mitigate or eliminate the risks and consequences are at the discretion of those entities.

The ability of the interconnected transmission systems to withstand probable and extreme contingencies must be determined by simulated testing of the systems as prescribed in these I.A. Standards on Transmission Systems.

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.

Standards

S1. The interconnected transmission systems shall be planned, designed, and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet 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 (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

S2. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels, under the conditions of the contingencies as defined in Category B of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category B of Table I (attached).

S3. The interconnected transmission systems shall be planned, designed, and constructed 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 conditions of the contingencies 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.

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category C of Table I (attached).

S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I (attached).

WECC-S1 ***In addition to NERC Table I, WECC Member Systems shall comply with the WECC Disturbance-Performance Table of Allowable Effects on Other Systems contained in this section when planning the Western Interconnection. The WECC Disturbance-Performance Table does not apply internal to a WECC Member System.***

WECC-S2 ***The NERC Category C.5 initiating event of a non-three phase fault with normal clearing shall also apply to the credible common mode contingency of two adjacent circuits on separate towers. The credibility of such an outage depends upon the credibility of the common mode failure. The credible outage of two circuits could result from a lightning storm or forest fire. Considerations in the determination of credibility should include line design; length; location, whether forested, agricultural, mountainous, etc.; outage history; operational guidelines; and separation between circuits.***

WECC-S3 *The common mode simultaneous outage of two generator units connected to the same switchyard, not addressed by the initiating events in NERC Category C, shall not result in cascading.*

WECC-S4 *The loss of multiple bus sections as a result of a failure or delayed clearing of a bus tie or bus sectionalizing breaker shall meet the performance specified for Category D of the WECC Disturbance-Performance Table.*

WECC-S5 *For contingencies involving existing or planned facilities, the Table W-1 performance category can be adjusted based on actual or expected performance (e.g. event outage frequency and consideration of impact) after going through the WECC Phase I Probabilistic Based Reliability Criteria (PBRC) Performance Category Evaluation (PCE) Process.*

WECC-S6 *Any contingency adjusted to Category D must not result in a cascading outage unless the MTBF is greater than 300 years (frequency less than 0.0033 outages/year) or the initiating disturbances and corresponding impacts are confined to either a radial system or a local network.*

WECC-S7 *For any event that has actually resulted in cascading, action must be taken so that future occurrences of the event will not result in cascading, or it must go through the PBRC process and demonstrate that the MTBF is greater than 300 years (frequency less than 0.0033 outages/year).*

WECC-S8 *The WECC Planning Standards require systems to meet the same performance category for unsuccessful reclosing as that required for the initiating disturbance without reclosing.*

WECC-S9 *To the extent permitted by NERC Planning Standards, individual systems or a group of systems may apply standards that differ from the WECC specific standards in Table W-1 for internal impacts. If the individual standards are less stringent, other systems are permitted to have the same impact on that part of the individual system for the same category of disturbance. If these standards are more stringent, these standards may not be imposed on other systems. This does not relieve the system or group of systems from WECC standards for impacts on other systems.*

WECC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECTS ON OTHER SYSTEMS

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C	0.033 – 0.33	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D	< 0.033	Nothing in addition to NERC		

Notes:

1. *The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.*

2. *As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.*

3. *Additional voltage requirements associated with voltage stability are specified in Standard I-D. If it can be demonstrated that post transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem.*

Table W-1

4. *Refer to Figure W-1 for voltage performance parameters.*

5. *Load buses include generating unit auxiliary loads.*

6. *To reach the frequency categories shown in the WECC Disturbance-Performance Table for Category C disturbances, it is presumed that some planned and controlled islanding has occurred. Underfrequency load shedding is expected to arrest this frequency decline and assure continued operation within the resulting islands.*

7. *For simulation test cases, the interconnected transmission system steady state loading conditions prior to a disturbance should be appropriate to the case. Disturbances should be simulated at locations on the system that result in maximum stress on other systems. Relay action, fault clearing time, and reclosing practice should be represented in simulations according to the planning and operation of the actual or planned systems. When simulating post transient conditions, actions are limited to automatic devices and no manual action is to be assumed.*

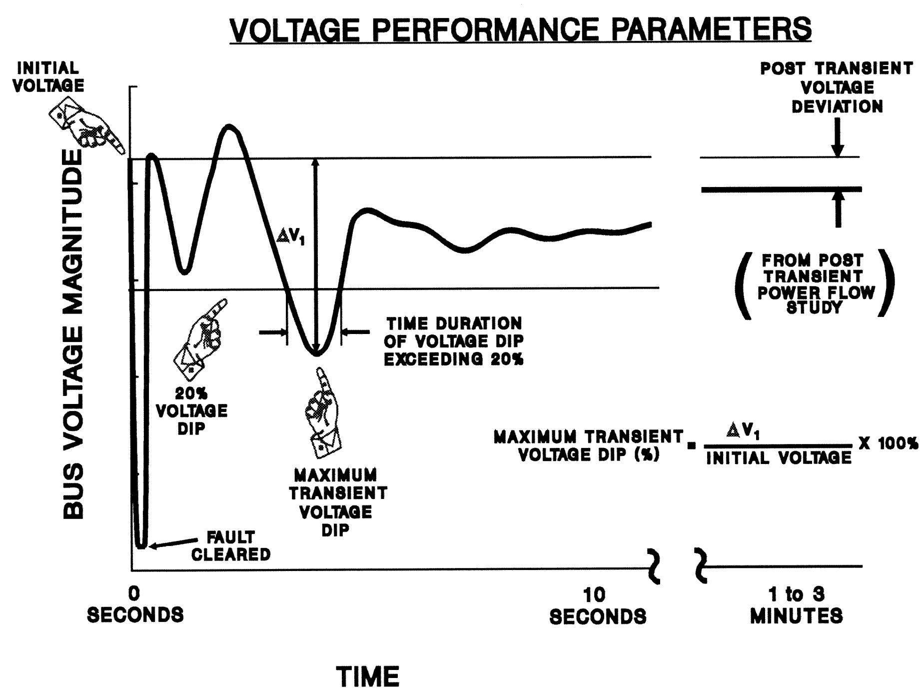

Figure W-1

Measurements

M1. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S1 are as defined in Category A (no contingencies) of Table I (attached) and summarized below:

a. Line and equipment loadings shall be within applicable thermal rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. All customer demands shall be supplied, and all projected firm (non-recallable reserved) transfers shall be maintained.
d. Stability of the network shall be maintained.

Assessment Requirements
Entities responsible for the reliability of interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S1.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Be supported by a current or past study that addresses the plan year being assessed.
2. Address any planned upgrades needed to meet the performance requirements of Category A.
3. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

System performance assessments based on system simulation testing shall show that with all planned facilities in service (no contingencies), established normal (pre-contingency) operating procedures in place, and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands.

Assessments shall include the effects of existing and planned reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category A of Table I.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M1), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M2. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S2 contingencies are as defined in Category B (event resulting in the loss of a single element) of Table I (attached) and summarized below:

a. Line and equipment loadings shall be within applicable rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. No loss of customer demand (except as noted in Table I, footnote b) shall occur, and no projected firm (non-recallable reserved) transfers shall be curtailed.
d. Stability of the network shall be maintained.
e. Cascading outages shall not occur.

Assessment Requirements
Entities responsible for the reliability of interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S2. Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be supported by a current or past study that addresses the plan year being assessed.

2. Assessments shall address any planned upgrades needed to meet the performance requirements of Category B.
3. Assessments shall be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

System performance assessments based on system simulation testing shall show that for system conditions where the initiating event results in the loss of a single generator, transmission circuit, or bulk system transformer, and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. No planned loss of customer demand nor curtailment of projected firm transfers shall be necessary to meet these performance requirements, except as noted in footnote b of Table I. This system performance shall be achieved for the described contingencies of Category B of Table I.

Assessments shall consider all contingencies applicable to Category B, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category B of Table I. Assessments shall also include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems, to ensure that protection systems and control devices are sufficient to meet the system performance as defined in Category B of Table I.

The systems must be capable of meeting Category B requirements while accommodating 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.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall also be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M2), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M3. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S3 are as defined in Category C (event(s) resulting in the loss of two or more elements) of Table I (attached) and summarized below:

a. Line and equipment loadings shall be within applicable thermal rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. Planned (controlled) interruption of customer demand or generation (as noted in Table I, footnote d) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.
d. Stability of the network shall be maintained.
e. Cascading outages shall not occur.

Assessment Requirements
Entities responsible for the reliability of the interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S3.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

2. Assessments of the near-term planning horizon shall be supported by a current or past study that addresses the plan year being assessed. For assessments of the longer-term planning horizon, a current or past study that addresses the plan year being assessed shall only be required if marginal conditions that may have longer lead-time solutions have been identified in the near-term assessment.

3. Assessments shall address any planned upgrades needed to meet the performance requirements of Category C.

System performance assessments based on system simulation testing shall show that for system conditions where (See Table I Category C)

1. The initiating event results in the loss of two or more elements, or
2. Two separate events occur resulting in two or more elements out of service with time for manual system adjustments between events,

and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. Planned outages of customer demand or generation (as noted in Table I, footnote d) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed. This system performance shall be achieved for the described contingencies of Category C of Table I.

Assessments shall consider all contingencies applicable to Category C, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category C of Table I. Assessments shall also include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems, to ensure that protection systems and control devices are sufficient to meet the system performance as defined in Category C of Table I.

The systems must be capable of meeting Category C requirements while accommodating 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.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall also be conducted for near (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M3), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M4. Entities responsible for the reliability of the interconnected transmission systems shall assess the risks and system responses for Standard S4 as defined in Category D of Table I (attached).

Assessment Requirements
Entities responsible for the reliability of the interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S4.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be conducted for near-term (years one through five) planning horizons.

2. Assessments shall be supported by a current or past study that addresses the plan year being assessed.

System performance assessments based on system simulation testing shall evaluate system conditions of Table I Category D, with all projected firm transfers modeled.

Assessments shall consider all contingencies applicable to Category D, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources, and shall include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems.

Assessments shall consider 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 when evaluating the effects of Category D events.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall be conducted for near-term (years one through five) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses.

Corrective Plan Requirements
None required.

Reporting Requirements
The documentation of results of these reliability assessments and mitigation measures shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M5. Entities responsible for the reliability of the interconnected transmission systems shall document their assessment activities in compliance with the I.B. Standard on Reliability Assessment to ensure that their respective systems are in compliance with these I.A. Standards on Transmission Systems. This documentation shall be provided to NERC on request. (S1, S2, S3, and S4)

Guides

G1. The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations.

G2. Studies affecting more than one system owner or user should be conducted on a joint interconnected system basis.

G3. The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network.

G4. The interconnected transmission systems should provide flexibility in switching arrangements, voltage control, and other protection system measures to ensure reliable system operation.

G5. The assessment of transmission system capability and the need for system enhancements should take into account themaintenance outage plans of the transmission facility owners. These maintenance plans should be coordinated on an intra- and interregional basis.

G6. The interconnected transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

G7 Reliability assessments should examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Pre-contingency system conditions chosen for analysis should include contracted firm (non-recallable reserved) transmission services.

G8. Annual updates to the transmission assessments should be performed, as appropriate, to reflect anticipated significant changes in system conditions.

G9. Extreme contingency evaluations should be conducted to measure the robustness of the interconnected transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical (and in some cases not possible) to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to control or limit the scope of such cascading or system instability events and the significant economic and social impacts that can result.

G10. It may be appropriate to conduct the extreme contingency assessments on a coordinated intra- or interregional basis so that all potentially affected entities are aware of the possibility of cascading or system instability events.

WECC-G1 ***The contingencies specified for each Category in the NERC table and the outage frequency range provided in the WECC table provide a basis for***

estimating performance categories for disturbances that are not in the NERC Table or for disturbances that have sufficient data available to estimate their probability of occurrence.

WECC-G2 ***Each system should provide sufficient transmission capacity within its system to serve its load and meet its transmission obligations to others without unduly relying on or without imposing an undue degradation of reliability on any other system, unless pursuant to prior agreement with the system(s) so affected. Each system should provide sufficient transmission capacity, by ownership or agreement, for scheduling power transfers between its system and any other system. In transferring such power there should be no undue degradation of reliability on any system not a party to the transfer.***

WECC-G3 ***Each system should plan its system with adequate transfer capability so that its power transfers will not have an undue loop flow impact on other systems, and so that planned schedules do not depend on opposing loop flow to keep actual flows within the path transfer capability. A system adding facilities should recognize that the addition itself could result in a component of loop flow that should be accommodated. Loop flow is an inherent characteristic of interconnected AC transmission systems and the mere presence of loop flow on circuits other than those of the transfer path is not necessarily an indication of a problem in planning or in scheduling practices.***

WECC-G4 ***An initiating event of a three phase fault may be used for screening contingencies of two adjacent circuits. However, the required performance will be as specified in Table I for category C5 (Non three phase fault with Normal Clearing: Double Circuit Tower-line) events. Simulations meeting the criteria with a three-phase fault may be assumed to meet the criteria with a non-three phase fault and normal clearing.***

TERMS USED IN THE WECC PLANNING STANDARDS

Post Transient Voltage Deviation

In the context of these Planning Standards, post transient voltage deviation refers to "voltage drop" not "voltage rise," and the post-transient time frame is considered to be one to three minutes after a system disturbance occurs. This allows available automatic voltage support measures to take place, but does not allow the effects of operator manual actions or Area Generation Control response. The recommended simulation is a post transient power flow that simulates all automatic action but not manual actions and not area interchange control. The post transient voltage deviation standards do not fully identify all potential voltage collapse problems. Voltage collapse standards are discussed in greater depth in Standard I D.

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B – Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Single Single Single Single	A/R A/R A/R A/R	A/R A/R A/R A/R	Yes Yes Yes Yes	No[b] No[b] No[b] No[b]	No No No No
	Single Pole Block, Normal Clearing[f]: 4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C – Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]: 1. Bus Section 2. Breaker (failure or internal fault)	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[f]: 5. Any two circuits of a multiple Circuit towerline[g]	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 6. Generator 8. Transformer 7. Transmission Circuit 9. Bus Section	Multiple Multiple	A/R A/R	A/R A/R	Yes Yes	Planned/Controlled[d] Planned/Controlled[d]	No No

D [e] – Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing [f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [f]: 5. Breaker (failure or internal fault) Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	Evaluate for risks and consequences. • May involve substantial loss of customer demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems.

Footnotes to Table I.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria

Introduction

NERC, through its Planning Committee (or successor group(s)), reviews and assesses the overall reliability (adequacy and security) of the interconnected bulk electric systems, both existing and as planned, to ensure that each Region (subregion) complies with the NERC Planning Standards and its own Regional planning criteria.

NERC also conducts special reliability assessments on a Regional, interregional, and Interconnection basis as conditions warrant or as requested by the NERC Planning Committee or Board of Trustees. Such special reliability assessments may include, among others, security assessments, operational assessments, evaluations of emergency response preparedness, adequacy of fuel supply and hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the adequacy of the interconnected bulk electric systems in North America.

To carry out these reviews and assessments of the overall reliability of the interconnected bulk electric systems, NERC (and its Planning Committee or successor group(s)) must have sufficient data and input from the Regions to prepare and publish NERC's annual seasonal (summer and winter) and longer-range assessments of the reliability of the interconnected bulk electric systems. Additional data may also be required for the special reliability assessments.

NERC's adequacy and security assessments must ensure the requirements stated in each Region's planning criteria and the **NERC Planning Standards** are met.

The Regions must also assess their Regional bulk electric system reliability within the context of the interconnected networks. Therefore, the Region and its members must coordinate their assessment efforts not only within their Region, but also with neighboring systems and Regions.

Standards

S1. The overall reliability (adequacy and security) of the Regions' interconnected bulk electric systems, both existing and as planned, shall comply with the NERC Planning Standards and each Region's respective Regional planning criteria.

Measurements

M1. Each Region shall annually conduct reliability assessments of its respective existing and planned Regional bulk electric system (generation and transmission facilities) for: 1) seasonal (winter and summer of the current year) conditions or other current-year system conditions as deemed appropriate by the Region, and 2) near-term (years one through five) and longer-term (years six through ten) planning horizons. For the near term, detailed assessments shall be conducted. For the longer term, assessment shall focus on the analysis of trends in resources and transmission adequacy, other industry trends and developments, and reliability concerns.

Similarly, the Regions shall also annually conduct interregional reliability assessments to ensure that the Regional bulk electric systems are planned and developed on a coordinated or joint basis to preserve the adequacy and security of the interconnected bulk electric systems.

Regional and interregional reliability assessments shall demonstrate that the performance of these systems are in compliance with NERC Standard I.A and respective Regional transmission and generation criteria. These assessments shall also identify key reliability issues and the risks and uncertainties affecting adequacy and security.

Regional and interregional seasonal, near-term, and longer-term reliability assessments shall be provided to NERC on an annual basis.

In addition, special reliability assessments shall also be performed as requested by the NERC Planning Committee or Board of Trustees under their specific directions and criteria. Such assessments may include, among others, security assessments, operational assessments, evaluations of emergency response preparedness, adequacy of fuel supply and hydro conditions, reliability impacts of new or proposed environmental rules and regulations, and reliability impacts of new or proposed legislation that affects, has affected, or has the potential to affect the adequacy of the interconnected bulk electric systems in North America.

M2. Each Region shall provide, as requested (seasonally, annually, or as otherwise specified) by NERC, system data, including past, existing, and future facility and bulk electric system data, reports, and system performance information, necessary to assess reliability and compliance with the NERC Planning Standards and the respective Regional planning criteria.

The facility and bulk electric system data, reports, and system performance information shall include, but not be limited to, one or more of the following types of information as outlined below:

1. Electric Demand and Net Energy for Load (actual and projected demands and net energy for load, forecast methodologies, forecast assumptions and uncertainties, and treatment of demand-side management)

2. Resource Adequacy and Supporting Information (Regional assessment reports, existing and planned resource data, resource availability and characteristics, and fuel types and requirements)

3. Demand-Side Resources and Their Characteristics (program ratings, effects on annual system loads and load shapes, contractual arrangements, and program durations)

4. Supply-Side Resources and Their Characteristics (existing and planned generator units, ratings, performance characteristics, fuel types and availability, and real and reactive capabilities)

5. Transmission System and Supporting Information (thermal, voltage, and stability limits, contingency analyses, system restoration, system modeling and data requirements, and protection systems)

6. System Operations and Supporting Information (extreme weather impacts, interchange transactions, and congestion impacts on the reliability of the interconnected bulk electric systems)

7. Environmental and Regulatory Issues and Impacts (air and water quality issues, and impacts of existing, new, and proposed regulations and legislation)

Introduction

All facilities involved in the generation, transmission, and use of electricity must be properly connected to the bulk interconnected transmission systems (generally 100 kV and higher) to avoid degrading the reliability of the electric systems to which they are connected.

To avoid adverse impacts on reliability when making connections to the interconnected bulk electric systems, generation and transmission owners and electricity end-users must meet facility connection and performance requirements as specified by those responsible for the reliability of the bulk interconnected transmission systems.

Standards

S1. Facility connection requirements shall be documented, maintained, and published by voltage class, capacity, and other characteristics that are applicable to generation, transmission, and electricity end-user facilities which are connected to, or being planned to be connected to, the bulk interconnected transmission systems.

S2. Generation, transmission, and electricity end-user facilities, and their modifications, shall be planned and integrated into the interconnected transmission systems in compliance with NERC Planning Standards, applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.

Measurements

M1. Transmission providers, in conjunction with transmission owners, shall document, maintain, and publish facility connection requirements for

a. generation facilities,
b. transmission facilities, and
c. end-user facilities

to ensure compliance with **NERC Planning Standards** and applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria and facility connection requirements.

Facility connection requirements shall address, but are not limited to, the following items:

1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.

2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.

3. Voltage level and MW and Mvar capacity or demand at point of connection.
4. Breaker duty and surge protection.
5. System protection and coordination.
6. Metering and telecommunications.
7. Grounding and safety issues.
8. Insulation and insulation coordination.
9. Voltage, reactive power, and power factor control.
10. Power quality impacts.
11. Equipment ratings.
12. Synchronizing of facilities.
13. Maintenance coordination.
14. Operational issues (abnormal frequency and voltages).
15. Inspection requirements for existing or new facilities.
16. Communications and procedures during normal and emergency operating conditions.

Facility connection requirements shall be maintained and updated as required.

Documentation of these requirements shall be available to the users of the transmission systems, the Regions, and NERC on request (five business days). (S1)

M2. Those entities responsible for the reliability of the interconnected transmission systems and those entities seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall coordinate and cooperate on their respective assessments to evaluate the reliability impact of the new facilities and their connections on the interconnected transmission systems and to ensure compliance with **NERC Planning Standards** and applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.

The entities involved shall present evidence that they have cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved. Assessments shall include steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under Standard I.A.

Documentation of these assessments shall include study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

This documentation shall be retained for three years and shall be provided to the Regions and NERC on request (within 30 days). (S2)

Guides

G1. Inspection requirements for connected facilities or new facilities to be connected should be included in the facility connection requirements documentation.

G2. Notification of new facilities to be connected, or modifications of existing facilities already connected to the interconnected transmission systems should be provided to those responsible for the reliability of the interconnected transmission systems as soon as feasible to ensure that a review of the reliability impact of the facilities and their connections can be performed and that the facilities are placed in service in a timely manner.

G3. Use of common data and modeling techniques is encouraged.

Introduction

Sufficient reactive resources must be located throughout the electric systems, with a balance between static and dynamic characteristics. Both static and dynamic reactive power resources are needed to supply the reactive power requirements of customer demands and the reactive power losses in the transmission and distribution systems, and provide adequate system voltage support and control. They are also necessary to avoid voltage instability and widespread system collapse in the event of certain contingencies. Transmission systems cannot perform their intended functions without an adequate reactive power supply.

Dynamic reactive power support and voltage control are essential during power system disturbances. Synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) can provide dynamic support. Transmission line charging and series and shunt capacitors are also sources of reactive support, but are static sources.

Reactive power sources must be distributed throughout the electric systems among the generation, transmission, and distribution facilities, as well as at some customer locations. Because customer reactive demands and facility loadings are constantly changing, coordination of distribution and transmission reactive power is required. Unlike active or real power (MWs), reactive power (Mvars) cannot be transmitted over long distances and must be supplied locally.

Standard

S1. Reactive power resources, with a balance between static and dynamic characteristics, shall be planned and distributed throughout the interconnected transmission systems to ensure system performance as defined in Categories A, B, and C of Table I in the I.A. Standards on Transmission Systems.

WECC-S1 ***For transfer paths, post-transient voltage stability is required with the path modeled at a minimum of 105% of the path rating (or Operational Transfer Capability) for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the path modeled at a minimum of 102.5% of the path rating (or Operational Transfer Capability).***

WECC-S2 ***For load areas, post-transient voltage stability is required for the area modeled at a minimum of 105% of the reference load level for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the area modeled at a minimum of 102.5% of the reference load level. For this standard, the reference load level is the maximum established planned load limit for the area under study.***

WECC-S3 ***Specific requirements that exceed the minimums specified in I.D WECC-S1 and S2 may be established, to be adhered to by others, provided that technical justification has been approved by the Planning Coordination Committee of the WECC.***

WECC-S4 ***These Standards apply to internal WECC Member Systems as well as between WECC Member Systems.***

Measurements

M1. Entities responsible for the reliability of the interconnected transmission systems shall conduct assessments (at least every five years or as required by changes in system conditions) to ensure reactive power resources are available to meet projected customer demands, firm (non-recallable) electric power transfers, and the system performance requirements as defined in Categories A, B, and C of Table I of the I.A. Standards on Transmission Systems. Documentation of these assessments shall be provided to the Regions and NERC on request. (S1)

M2. Generation owners and transmission providers shall work jointly to optimize the use of generator reactive power capability. These joint efforts shall include:

a. Coordination of generator step-up transformer impedance and tap specifications and settings,
b. Calculation of underexcited limits based on machine thermal and stability considerations, and
c. Ensuring that the full range of generator reactive power capability is available for applicable normal and emergency network voltage ranges. (S1)

Guides

G1. Transmission owners should plan and design their reactive power facilities so as to ensure adequate reactive power reserves in the form of dynamic reserves at synchronous generators, synchronous condensers, and static var compensators (SVCs and STATCOMs) in anticipation of system disturbances. For example, fixed and mechanically-switched shunt compensation should be used to the extent practical so as to ensure reactive power dynamic reserves at generators and SVCs to minimize the impact of system disturbances.

G2. Distribution entities and customers connected directly to the transmission systems should plan and design their systems to operate at close to unity power factor to minimize the reactive power burden on the transmission systems.

G3. At continuous rated power output, new synchronous generators should have an overexcited power factor capability, measured at the generator terminals, of 0.9 or less and an underexcited power factor capability of 0.95 or less.

If a synchronous generator does not meet this requirement, the generation owner should make alternate arrangements for supplying an equivalent dynamic reactive power capability to meet the area's reactive power requirements.

G4. Reactive power compensation should be close to the area of high reactive power consumption or production.

G5. A balance between fixed compensation, mechanically-switched compensation, and continuously-controlled equipment should be planned.

G6. Voltage support and voltage collapse studies should conform to Regional guidelines.

G7. Power flow simulation of contingencies, including P-V and V-Q curve analyses, should be used and verified by dynamic simulation when steady-state analyses indicate possible insufficient voltage stability margins.

G8. Consideration should be given to generator shaft clutches or hydro water depression capability to allow generators to operate as synchronous condensers.

WECC-G1 ***Each system should plan and provide, by ownership or agreement, sufficient reactive power capacity and voltage control facilities to satisfy the requirements of its own system***

WECC-G2 ***Reactive Power Margin Requirements: The development of "Reactive Power Margin Requirements" based on the V-Q methodology developed by TSS (e.g., 400 MVAR at a particular bus) provides one alternate way to screen cases and determine whether or not they likely meet this criteria. The "Reactive Power Margin Requirement" is a proxy for Standards I.D WECC-S1 through WECC-S3.***

WECC-G3 ***Identification of Critical Conditions: It may be necessary to study a variety of load, transfer, and generation patterns to identify the most critical set of system conditions. For example, various conditions should be considered, such as: peak load conditions with maximum imports, low load conditions with minimum generation, and maximum interface flow conditions with worst case load conditions.***

WECC-G4 ***When developing the 105% and 102.5% load or transfer cases to demonstrate conformance with I.D WECC-S1, S2, and S3, conformance with the***

performance requirement (e.g., facility thermal loading limits) identified in Section I.A is not required.

WECC-G5 *Load Voltage Response Assumption: Loads and distribution regulating devices in the study area should be modeled as detailed as is practical. If detailed load models cannot be estimated, the loads can be represented as constant MVA in long-term (post transient) voltage stability study; this representation approximates the effect of voltage regulation by LTC bulk power delivery transformers and distribution voltage regulators. For short-term (transient) voltage stability and dynamic simulation, dynamic modeling of induction motors is recommended.*

WECC-G6 *Load Shedding: Controlled load interruption, as allowed in Table I of the NERC/WECC Planning Standards, is allowed to meet these standards.*

WECC-G7 *Automatic Switching: Planned operation of automatic switching (distribution voltage regulators, switched static devices, etc.) may be modeled to meet these standards.*

WECC-G8 *Voltage magnitudes alone are poor indicators of voltage stability or security because the system may be near collapse even if voltages are near normal depending on the system characteristics. The system should be planned so that there is sufficient margin between normal operating point and the collapse point to allow for reliable system operation.*

WECC-G9 *In assessing the requirements under WECC-S3, relevant system variations and uncertainties should be considered. Types of analysis that may be used include P-V, V-Q, and dynamic studies.*

WECC-G10 *Voltage stability analysis and the evaluation of balance between dynamic and static reactive power resources may be performed using the methodologies adopted by TSS.*

Introduction — Total and Available Transfer Capabilities

A competitive electricity market is dependent on the availability of transmission services. The availability of these services must be based on the physical and electrical characteristics and capabilities of the interconnected transmission networks as reliably planned and operated under the **NERC Planning Standards**, the NERC Operating Policies, and applicable Regional, subregional, power pool, and individual system criteria.

The total transfer capability (TTC) and the available transfer capability (ATC) for particular directions must be available to the market participants. These transfer capabilities are generally calculated through computer simulations of the interconnected transmission systems under a specific set of system conditions.

TTC and ATC values must balance both technical and commercial issues. The definitions of the key TTC and ATC transfer capability terms that bridge the technical characteristics of interconnected transmission system performance and the commercial requirements associated with transmission service requests are as follows:

- The total transfer capability (TTC) is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.

- Available transfer capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as TTC less existing transmission commitments (including retail customer service), less a capacity benefit margin (CBM)), less a transmission reliability margin (TRM). (The transfer capability margins - CBM and TRM - are defined under section I.E.2 of the Planning Standards document.)

  ATC is expressed as:

  ATC = TTC – Existing Transmission Commitments (includes retail customer service) – CBM – TRM

  Depending on the methodology used, either ATC or TTC may be calculated first.

TTC and ATC values are projected values. They are intended to indicate the available transfer capabilities of the interconnected transmission network.

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above

NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurements

M1. Each Region, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. Certain systems that are not required to post ATC values are exempt from this Standard.

This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's TTC and ATC methodology shall (S1):

a. Include a narrative explaining how TTC and ATC values are determined.
b. Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system, are included.
c. Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.
d. Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)
e. Require that TTC and ATC values and postings within the current week be determined at least once per day, that daily TTC and ATC values and postings for day 8 through the first month be determined at least once per week, and that monthly TTC and ATC values and postings for months 2 through 13 be determined at least once per month.
f. Indicate the treatment and level of customer demands, including interruptible demands.
g. Specify how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used within the Region and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regions. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.

h. Describe how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.
i. Describe the Region's practice on the netting of transmission reservations for purposes of TTC and ATC determination.

Each Regional TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.

The most recent version of the documentation of each Region's TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M2. Eliminated. Requirements included in Measurement M3.

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

M4. Each Region, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market. (S1

Each Region's procedure shall specify (S1):

a. The name, telephone number, and email address of a contact person to whom concerns are to be addressed.
b. The amount of time it will take for a response.
c. The manner in which the response will be communicated (e.g., email, letter, telephone, etc.).
d. What recourse a customer has if the response is deemed unsatisfactory.

Guides

G1. The Regional responses to transmission user concerns or questions regarding the ATC and TTC methodology and values of the transmission provider(s) should be made publicly available, possibly on a web site, for consistency and to avoid duplicative customer questions.

Introduction — Transfer Capability Margins

In defining the components that comprise Available Transfer Capability (ATC), two transmission transfer capability margin terms, known as Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM), are introduced.

The definitions for CBM and TRM are:

- Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

- Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

The methodologies used to determine CBM and TRM and the resulting CBM and TRM values impact ATC and, therefore, must be available to the market participants.

Standards

S1 Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurements

M1. Each Region, in conjunction with its members, shall develop and document a Regional CBM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's CBM methodology shall (S1):

a. Specify that the method used by each Regional member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.
b. Specify the frequency of calculation of the generation reliability requirement and associated CBM values.
c. Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.
d. Require that CBM be preserved only on the transmission provider's system where the load serving entity's load is located (i.e., CBM is an import quantity only).
e. Describe the inclusion or exclusion rationale for generation resources of each LSE including those generation resources not directly connected to the transmission provider's system but serving LSE loads connected to the transmission provider's system.
f. Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system but not obligated to serve native/network load connected to the transmission provider's system.

g. Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.
h. Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.
i. Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).
j. Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.

Each Regional CBM methodology shall address each of the items listed above and shall explain its use, if any, in determining CBM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining CBM values.

The most recent version of the documentation of each Region's CBM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M2. Eliminated. Requirements included in Measurement M3.

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review the CBM calculations and values of member transmission providers to ensure that they comply with the Regional CBM methodology and are periodically updated (at least annually) and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

This Regional procedure shall:

a. Indicate the frequency under which the verification review shall be implemented.
b. Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.
c. Require review of the consistency of the transmission provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are also addressed in the planning

criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.

d. Require CBM values to be periodically updated (at least annually) and available to the Regions, NERC, and transmission users in the electricity markets.

The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).

M4. Each transmission provider shall document and make available its procedures on the use of CBM (scheduling of electrical energy against a CBM preservation) to the Regions, NERC, and the transmission users in the electricity market.

These procedures shall:

a. Require that CBM is to be used only after the following steps have been taken (as time permits): all non-firm sales have been terminated, direct-control load management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to reestablish operating reserves.
b. Require that CBM shall only be used if the LSE calling for its use is experiencing a generation deficiency and its transmission provider is also experiencing transmission constraints relative to imports of energy on its transmission system.
c. Describe the conditions under which CBM may be available as non-firm transmission service. (S1)

The transmission providers shall make their CBM use procedures available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

M5. Each transmission provider that uses CBM shall report to the Regions, NERC, and the transmission users the use of CBM by the load-serving entities' loads on its system, except for CBM sales as non-firm transmission service. This disclosure may be after the fact. (S1)

Within 15 days after the use of CBM for emergency purposes, a transmission provider shall make available the 1) circumstances, 2) duration, and 3) amount of

CBM used. This information shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

The use of CBM also shall be consistent with the transmission provider's CBM use procedures.

The scheduling of energy against a CBM preservation as non-firm transmission service need not be disclosed to comply with this Standard.

M6. Each Region, in conjunction with its members, shall develop and document a Regional TRM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S2)

Each Region's TRM methodology shall (S2):

a. Specify the update frequency of TRM calculations.
b. Specify how TRM values are incorporated into ATC calculations.
c. Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values.

   The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM: aggregate load forecast error (not included in determining generation reliability requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window).

   Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.

d. Describe the conditions, if any, under which TRM may be available to the market as non-firm transmission service.
e. Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional TRM methodology.

Each Regional TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.

The most recent version of the documentation of each Region's methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

M7. Eliminated. Requirements included in Measurement M8.

M8. Each Region, in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and values of member transmission providers to ensure that they comply with the Regional TRM methodology and are periodically updated and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S2)

This Regional procedure shall:

a. Indicate the frequency under which the verification review shall be implemented.
b. Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users.
c. Require review of the consistency of the transmission provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.
d. Require TRM values to be periodically updated (at least prior to each season — winter, spring, summer, and fall), as necessary, and made available to the Regions, NERC, and transmission users in the electricity market.

The documentation of the Regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).

Introduction

Recorded information about transmission system faults or disturbances is essential to determine the performance of system components and to analyze the nature and cause of a disturbance. Such information can help to identify equipment misoperations, and the causes of oscillations that may have contributed to a disturbance. Protection system and control deficiencies can also be analyzed and corrected, reducing the risk of recurring misoperations. Transient modeling data can be gathered from fault and sequence-of-event monitoring equipment and long-time modeling data can be gathered from dynamic monitoring equipment using wide-area measurement techniques or swing sensors.

Standards

S1. Requirements shall be established on a Regional basis for the installation of disturbance monitoring equipment (e.g., sequence-of-event, fault recording, and dynamic disturbance recording equipment) that is necessary to ensure data is available to determine system performance and the causes of system disturbances.

S2. Requirements for providing disturbance monitoring data for the purpose of developing, maintaining, and updating transmission system models shall be established on a Regional basis.

Measurements

M1. Each Region shall develop comprehensive requirements for the installation of disturbance monitoring equipment to ensure data is available to determine system performance and the causes of system disturbances.

The comprehensive Regional requirements shall include the following items:

Technical requirements:

1. Type of data recording capability (e.g., sequence-of-event, fault recording, dynamic disturbance recording)
2. Equipment characteristics (e.g., recording duration requirements, time synchronization requirements, data format requirements, event triggering requirements)
3. Monitoring, recording, and reporting capabilities of the equipment (e.g., voltage, current, MW, Mvar, frequency)
4. Data retention capabilities (e.g., length of time data is to be available for retrieval)

Criteria for the location of monitoring equipment:
5. Regional coverage requirements (e.g., by voltage, geographic area, electric area/subarea)
6. Installation requirements (e.g., substations, transmission lines, generators)

Testing and maintenance requirements:
7. Responsibility for maintenance and/or testing

Documentation requirements:
8. Requirements for periodic updating, review, and approval of the Regional requirements

The Regional requirements shall be provided to other Regions and NERC on request (five business days).

M2. Regional members shall provide to their respective Regions a list of their disturbance monitoring equipment that is installed and operational in compliance with Regional requirements. (S1)

M3. Each generation owner and transmission provider shall maintain a database of all disturbance monitoring equipment installations, and shall provide such information to the Region and NERC on request. (S1)

M4. Each Region shall establish requirements for providing disturbance monitoring data to ensure that data is available to determine system performance and the causes of system disturbances. Documentation of Regional data reporting requirements shall be provided to appropriate Regions and NERC on request. (S2)

M5. Regional members shall provide to their respective Regions system fault and disturbance data in compliance with Regional requirements. Each Region shall maintain and annually update a database of the recorded information. (S1, S2)

M6. Regional members shall use recorded data from disturbance monitoring equipment to develop, maintain, and enhance steady-state and dynamic system models and generator performance models. (S2)

Guides

G1. Data from transmission system disturbance monitoring equipment should be in a consistent, time synchronized format.

G2. The Regional database should be used to identify locations on the transmission systems where additional disturbance monitoring equipment may be needed.

G3. The monitored data from disturbance monitoring equipment should be used to develop, maintain, validate, and enhance generator performance models and steady-state and dynamic system models.

G4. Each Region should establish and coordinate the requirements for the installation of disturbance monitoring equipment with neighboring Regions.

II. System Modeling Data Requirements — Discussion

System modeling is the first step toward reliable interconnected transmission systems. The timely development of system modeling data to realistically simulate the electrical behavior of the components in the interconnected networks is the only means to accurately plan for reliability. To achieve this purpose, the **NERC Planning Standards** on System Modeling Data Requirements (II) establishes a set of common objectives for the development and submission of necessary data for electric system reliability assessment.

The detail in which the various system components are modeled should be adequate for all intra- and interregional reliability assessment activities. This means that system modeling data should include sufficient detail to ensure that system contingency, steady-state, and dynamic analyses can be simulated. Furthermore, any qualified user should be able to recognize significant limiting conditions in any portion of the interconnected transmission systems.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Modeling Data Requirements (II) are provided in the following sections:

A. System Data
B. Generation Equipment
C. Facility Ratings
D. Actual and Forecast Demands
E. Demand Characteristics (Dynamic)

These **Standards, Measurements, and Guides** shall apply to all system modeling necessary to achieve interconnected transmission system performance as described in the Standards on System Adequacy and Security (I) in this report.

Introduction

Complete, accurate, and timely data is needed for system analyses to ensure the adequacy and security of the interconnected transmission systems, meet projected customer demands, and determine the need for system enhancements or reinforcements.

System analyses include steady-state and dynamic (all time frames) simulations of the electrical networks. Data requirements for such simulated modeling include information on system components, system configuration, customer demands, and electric power transactions.

Standard

S1. Electric system data required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurements

M1. All the users of the interconnected transmission systems shall provide appropriate equipment characteristics, system data, and existing and future interchange transactions in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Standard II.A.S1, M2 for the modeling and simulation of the steady-state behavior of the NERC Interconnections: Eastern, Western, and ERCOT.

This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Standard II.A.S1, M2). If no schedule exists, then data shall be provided on request (30 business days).

M2. The Regions, in coordination with the entities responsible for the reliability of the interconnected transmission systems, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regions shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection.

The following list describes the steady-state data that shall be addressed in the Interconnection-wide requirements:

1. Bus (substation and switching station): name, nominal voltage, electrical demand (load) supplied (consistent with the aggregated and dispersed substation demand data supplied per Standard II.D.), and location.

2. Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum ratings (net real and reactive power), regulated bus and voltage set point, and equipment status.

3. AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard II.C.), equipment status, and metering locations.

4. DC Transmission Line (overhead and underground): Line parameters, normal and emergency ratings, control parameters, rectifier data, and inverter data.

5. Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings (consistent with methodologies defined and ratings supplied per Standard II.C.), and equipment status.

6. Reactive Compensation (shunt and series capacitors and reactors): nominal ratings, impedance, percent compensation, connection point, and controller device.

7. Interchange Transactions: Existing and future interchange transactions and/or assumptions.

The data requirements and reporting procedures for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be documented, reviewed (at least every five years), and available to the Regions, NERC, and all users of the interconnected transmission systems on request (five business days).

M3. All users of the interconnected transmission systems shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional data requirements and reporting procedures as defined in Standard II.A.S1, M4 for the modeling and simulation of the dynamics behavior of the NERC Interconnections: Eastern, Western, and ERCOT.

This data shall be provided to the Regions, NERC, and those entities responsible for the reliability of the interconnected transmission systems as specified within the applicable reporting procedures (Standard II.A. S1, M4). If no schedule exists, then data shall be provided on request (30 business days).

M4. The Regions, in coordination with the entities responsible for the reliability of the interconnected transmission systems, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western and

ERCOT. Within an interconnection, the Regions shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. The following list describes the dynamics data that shall be addressed in the Interconnection-wide requirements:

1. Unit-specific dynamics data shall be reported for generators and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, and other associated generation equipment.

   However, estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.

   The Interconnection-wide requirements shall specify unit size thresholds for permitting: 1.) the use of non-detailed vs. detailed models, 2.) the netting of small generating units with bus load, and 3.) the combining of multiple generating units at one plant.

2. Device specific dynamics data shall be reported for dynamic devices, including, among others, static var controls (SVC), high voltage direct current systems (HVDC), flexible AC transmission systems (FACTS), and static compensators (STATCOM).

3. Dynamics data representing electrical demand (load) characteristics as a function of frequency and voltage.

4. Dynamics data shall be consistent with the reported steady-state (power flow) data supplied per Standard II.A.S1, M1.

The data requirements and reporting procedures for each of the NERC Interconnections (Eastern, Western, and ERCOT) shall be documented, reviewed (at least every five years), and available to the Regions, NERC, and all users of the interconnected systems on request (five business days).

M5. Data requirements for the steady-state and dynamics modeling of other associated transmission and generation facilities are included under the following sections of the **Standards**:

- Voltage Support and Reactive Power (I.D.)
- Disturbance Monitoring (I.F.)
- Generation Equipment (II.B.)

- Facility Ratings (II.C.)
- System Protection and Control (III)
- System Restoration (IV)

M6. Load-serving entities shall provide actual and forecast demands for their respective customers for steady-state and dynamics system modeling as specified in the respective steady-state and dynamics procedural manuals for the Interconnections and in compliance with the Actual and Forecast Demands (II.D.) and Demand Characteristics (Dynamic) (II.E.) Standards in this report. (S1)

Guides

G1. Any changes to interconnection tie line data should be agreed upon by all involved facility owners.

G2. The in-service date should be the year and season that a facility will be operable or placed in service.

G3. The out-of-service date should be the year and season that the facility will be retired or taken out of service.

G4. All data should be screened to detect inappropriate or inaccurate data.

G5. The reactive limits of generators should be periodically reviewed and field tested, as appropriate, to ensure that reported var limits are attainable. (See Generation Equipment Standard II.B.)

G6. Generating station service load (SSL) and auxiliary load representations should be provided to those entities responsible for the reliability of the interconnected transmission systems on request. The presence of SSL in a dynamic simulation will alter the bus angles derived from solution. This change in angle can be significant from the steady-state, dynamic, and voltage control perspectives, especially for large generating units.

G7. To accurately model system inertia, the netting of generation and customer demand should be avoided. For smaller units, the netting of generation and load is acceptable.

G8. Generating units equal to or greater than 50 MVA should generally be individually modeled. To maintain sufficient detail in the model, larger units should not be lumped together.

G9. Smaller generating units at a particular station may be lumped together and represented as one unit. The lumping of generating units at a station is acceptable where all units have the same electrical and control characteristics. Equivalent lumped units should generally not exceed 300 MVA.

G10. The dynamics data for each generating unit should be supplied on the machine's own MVA and kV base.

G11. Data for generator step-up transformers that are modeled as part of the generator data record should include effective tap ratios and per unit impedance (R and X values) on the transformer's MVA and kV base.

G12. Generator models should conform to *IEEE Guide for Synchronous Generator Modeling Practices in Stability Analysis* (IEEE Std. 1110-1991), or successor, Table 1, model 2.1 (for wound rotor machines) or 2.2 (for round rotor machines).

G13. Models of excitation systems, voltage regulators, and power system stabilizers should conform to *IEEE Recommended Practice for Excitation System Models for Power System Stability Studies* (IEEE Std. 421.5-1992), or successor, if a model appropriate to the equipment is available. If no model having the required characteristics is available, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Computer Models for Representation of Digital-Based Excitation Systems", IEEE Working Group Report, *IEEE Transactions on Energy Conversion, Vol. 11., No. 3, September 1996*, should be considered in developing models of digital-based excitation systems.

G14. Models of turbine-governor systems for steam units should conform to IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines", as published in *IEEE Transactions on Power Apparatus and Systems, Nov./Dec 1973*, model 1. If this model lacks the characteristics required to represent the dynamic response of the turbine governor system within the required frequency range and time interval, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Dynamic Models for Fossil Fueled Steam Units in Power System Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.6, No. 2, May 1991*, should be considered in developing models of steam turbine governor systems.

G15. Models of turbine-governor systems for hydro units should conform to IEEE Committee Report, "Dynamic Models for Steam and Hydro Turbines", as published in *IEEE Transactions on Power Apparatus and Systems, Nov./Dec. 1973,* model 2. If this model lacks the characteristics required to represent the dynamic response of the turbine governor system within the required frequency range and time interval, a library model or a user-written model of comparable detail with a block diagram may be supplied. "Hydraulic Turbine and Turbine Control Models for System Dynamic Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.7., No. 1,* *February 1992*, should be considered in developing models of hydro turbine governor systems.

G16. Models of turbine-governor systems for combustion turbine units should represent appropriate gains, limits, time constants and damping, and should include a parameter explicitly setting the ambient temperature load limit if this limits unit output for ambient temperatures expected during the season under study. "Dynamic Models for Combined Cycle Plants in Power System Studies", IEEE Working Group Report, *IEEE Transactions on Power Systems, Vol.9., No. 3, August 1994*, should be considered in developing models of combustion turbine governor systems.

Introduction

Validation of generator modeling data through field verification and testing is critical to the reliability of the interconnected transmission systems. Accurate, validated generator models and data are essential for planning and operating studies used to ensure electric system reliability.

Generating capability to meet projected system demands and provide the required amount of generation capacity margins is necessary to ensure service reliability. This generating capability must be accounted for in a uniform manner that ensures the use of realistically attainable values when planning and operating the systems or scheduling equipment maintenance.

Synchronous generators are the primary means of voltage and frequency control in the bulk interconnected electric systems. The correct operation of generator controls can be the crucial factor in whether the electric systems can sustain a severe disturbance without a cascading breakup of the interconnected network. Generator dynamics data is used to evaluate the stability of the electric systems, analyze actual system disturbances, identify potential stability problems, and analytically validate solutions for the identified problems.

Generator reactive capability is commonly derived from the generator real and reactive capability curves supplied by the manufacturer. Reactive power generation limits derived in this manner can be optimistic as heating or auxiliary bus voltage limits may be encountered before the generator reaches its maximum sustained reactive power capability. Manufacturer-provided design data may also not accurately reflect the characteristics of operational field equipment because settings can drift and components deteriorate over time. Field personnel may also change equipment settings (to resolve specific local problems) that may not be communicated to those responsible for developing a system modeling database and conducting system assessments. It is important to know the actual reactive power limits, control settings, and response times of generation equipment and to represent this information accurately in the system modeling data that is supplied to the Regions and those entities responsible for the reliability of the interconnected transmission systems.

Standard

S1. Generation equipment shall be tested to verify that data submitted for steady-state and dynamics modeling in planning and operating studies is consistent with the actual physical characteristics of the equipment. The data to be verified and provided shall include generator gross and net dependable capability, gross and net reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems.

Measurements

M1. Each Region shall establish and maintain procedures for generation equipment data verification and testing for all types of generating units in its Region. These procedures shall address generator gross and net dependable capability, reactive power capability, voltage regulator controls, speed/load governor controls, and excitation systems (including power system stabilizers and other devices, if applicable). These procedures shall also address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these procedures. (S1)

M2. Generation equipment owners shall annually test to verify the gross and net dependable capability of their units. They shall provide the Regions with the following information on request:

a. Summer and winter gross and net capabilities of each unit based on the power factor level expected for each unit at the time of summer and winter peak demand, respectively.

b. Active or real power requirements of auxiliary loads.

c. Date and conditions during tests (ambient and design temperatures, generator loadings, voltages, hydrogen pressure, high-side voltage, and auxiliary loads). (S1)

M3. Generation equipment owners shall test to verify the gross and net reactive power capability of their units at least every five years. They shall provide the Regions with the following information on request:

a. Maximum sustained reactive power capability (both lagging and leading) as a function of real power output and generator terminal voltage. If safety or system conditions do not allow testing to full capability, computations and engineering reports of estimated capability shall be provided.

b. Reason for reactive power limitation.

c. Reactive power requirements of auxiliary loads.

d. Date and conditions during tests (ambient and design temperatures, generator loadings, voltages, hydrogen pressure, high-side voltage, and auxiliary loads). (S1)

M4. Generation equipment owners shall test voltage regulator controls and limit functions at least every five years. Upon request, they shall provide the Regions with the status of voltage regulator testing as well as information that describes how generator controls coordinate with the generator's short-term capabilities and protective relays. Test reports shall include minimum and maximum excitation limiters (volts/hertz), gain and time constants, the type of voltage regulator control function, date tested, and the voltage regulator control setting. (S1)

M5. Generation equipment owners shall test speed/load governor controls at least every five years. Upon request, they shall provide the Regions with the status of governor tests as well as information that describes the characteristics (droop and deadband) of the speed/load governing system. (S1)

M6. Generation equipment owners shall verify the dynamic model data for excitation systems (including power system stabilizers and other devices, if applicable) at least every five years. Design data for new or refurbished excitation systems shall be provided at least one year prior to the in-service date with updated data provided once the unit is in service. Open circuit test response chart recordings shall be provided showing generator field voltage and generator terminal voltage. (Brushless units shall include exciter field voltage and current.) (S1)

Guides

G1. The following guidelines should be observed during testing of the reactive power capability of a generator:

a. The reactive power capability curve for each generating unit should be used to determine the expected reactive power capability.

b. Units should be tested while maintaining the scheduled voltage on the system bus. Coordination with other units may be necessary to maintain the scheduled voltage.

c. Hydrogen pressure in the generating unit should be at rated operating pressure.

d. Overexcited tests should be conducted for a minimum of two hours or until temperatures have stabilized.

e. When the maximum sustained reactive power output during the test is achieved, the following quantities should be recorded: generator gross MW and Mvar output, auxiliary load MW and Mvar, and generator and system voltage magnitudes.

G2. Most modern voltage regulators have limiting functions that act to bring the generating unit back within its capabilities when the unit experiences excessive field voltage, volts per hertz, or underexcited reactive current. These limiters are often intended to coordinate with other controls and protective relays. Testing should be done that demonstrates correct action of the controls and confirms the desired set points.

G3. Generation equipment owners should make a best effort to verify data necessary for system dynamics studies. An "open circuit step in voltage" is an easy to perform test that can be used to validate the generating unit and excitation system dynamics data. The open circuit test should be performed with the unit at rated speed and voltage but with its breakers open. Generator terminal voltage, field voltage, and field current (exciter field voltage and current for brushless excitation systems) should be recorded with sufficient resolution such that the change in voltages and current are clearly distinguishable.

G4. More detailed test procedures should be performed when there are significant differences between "open circuit step in voltage" tests and the step response predicted with the model data. Generator reactance and time constant data can be derived from standstill frequency response tests.

G5. The response of the speed/load governor controls should be evaluated for correct operation whenever there is a system frequency deviation that is greater than that established by the Regional procedures.

Introduction

Knowledge of facility ratings is essential for the reliable planning and operation of the interconnected transmission systems. Such ratings determine acceptable electrical loadings on equipment, before, during, and after system contingencies, and together with consideration of network voltage and system stability, determine the capability of the systems to deliver electric power from generation to point of use.

Standard

S1. Electrical facilities used in the transmission, and storage of electricity shall be rated in compliance with applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria.

Measurements

M1. Facility owners shall document the methodology (or methodologies) used to determine their electrical facility ratings. Further, the methodology(ies) shall be compliant with applicable Regional, subregional, power pool, and individual transmission provider/owner planning criteria.

The documentation shall include the methodology(ies) used to determine transmission facility ratings for both normal and emergency conditions. It shall also include methods for rating:

1. Transmission lines,
2. Transformers,
3. Series and shunt reactive elements,
4. Terminal equipment (e.g., switches, breakers, current transformers, etc.), and
5. Electrical energy storage devices (e.g., superconducting magnetic energy storage (SMES) system).

The rating of a transmission circuit shall not exceed the rating(s) of the most limiting element(s) in the circuit, including terminal connections and associated equipment. In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the rating for that facility.

Facility rating deviations from the methodology(ies), such as providing a consistent basis for jointly-owned facilities and unique applications, shall be documented. Ratings of jointly-owned facilities shall be coordinated and provided on a consistent basis.

The documentation shall identify the assumptions used to determine each of the facility ratings, including references to industry rating practices and standards (e.g., ANSI, IEEE, etc.). Seasonal ratings and variations in assumptions shall be included.

The documentation of the methodology(ies) used to determine transmission facility ratings shall be provided to the Regions and NERC on request (five business days).

M2. Facility owners shall have on file, or be able to readily provide, a document or data base identifying the normal and emergency ratings of all of their transmission facilities (e.g., lines, transformers, reactive devices, terminal equipment, and storage devices) that are part of the bulk interconnected transmission systems. Seasonal variations in ratings shall be included as appropriate.

The ratings shall be consistent with the methodology(ies) for determining facility ratings (Standard II.C. S1, M1) and shall be updated as facility changes occur. The ratings shall be provided to the Regions and NERC on request (30 business days).

Guides

G1. System modeling should use facility ratings based on weather assumptions appropriate for the seasonal (demand) conditions being evaluated.

G2. Facility ratings should be based on or adhere to applicable national electrical codes and electric industry rating practices consistent with good engineering practice.

G3. The ratings of bypass equipment do not need to be included in the facility rating determination. However, if it is the most limiting element, it should be identified and made available to the system operator. If an equipment failure results in extended use of bypass equipment, then the facility rating should be adjusted in the model and the Region and impacted operating entities should be informed.

Introduction

Actual demand data is needed for forecasting future electrical requirements, reliability assessments of past electric system events, load diversity studies, and validation of databases.

Forecast demand data is needed for system modeling and the analysis of the adequacy and security of the interconnected bulk electric systems, and for identifying the need and timing of system reinforcements to reliably supply customer electrical requirements.

Actual and forecast demand data generally includes hourly, monthly, and annual demands and monthly and annual net energy for load. This data may be required on an aggregated Regional, subregional, power pool, individual system basis, or on a dispersed transmission substation basis for system modeling and reliability analysis.

In addition to demands and net energy for load, that portion of demand that is included in or part of controllable demand-side management programs and which may be interrupted by system operators also may be required in evaluating the adequacy and security of the interconnected bulk electric systems.

Standards

S1. Actual demands and net energy for load data shall be provided on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Actual demand data on a dispersed substation basis shall be supplied when requested.

Forecast demands and net energy for load data shall be developed and maintained on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis. Forecast demand data shall also be developed on a dispersed substation basis.

S2. Controllable demand-side management (interruptible demands and direct control load management) programs and data shall be identified and documented.

Measurements

M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall have documentation identifying the scope and details of the actual and forecast (a) demand data, (b) net energy for load data, and (c) controllable demand-side management data to be reported for system modeling and reliability analysis.

The aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Standards IB, IIA, and IID.

The documentation of the scope and details of the data reporting requirements shall be available on request (five business days).

M2. The reporting procedures that are developed shall ensure that customer demands are not double counted or omitted in reporting actual or forecast demand data on either an aggregated or dispersed basis within an area or Region. (S1)

M3. Actual and forecast customer demand data and controllable demand-side management data reported to government agencies shall be consistent with data reported to those entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC. (S1, S2)

M4. The following information shall be provided annually on an aggregated Regional, subregional, power pool, individual system, or load serving entity basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard II.D.S1-S2, M1.

1. Integrated hourly demands in megawatts (MW) for the prior year.
2. Monthly and annual peak hour actual demands in MW and net energy for load in gigawatthours (GWh) for the prior year.
3. Monthly peak hour forecast demands in MW and net energy for load in GWh for the next two years.
4. Annual peak hour forecast demands (summer and winter) in MW and annual net energy for load in GWh for at least five years and up to ten years into the future, as requested.

M5. The following information shall be provided on a dispersed substation basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems:

a. Seasonal peak hour actual demands in MW and Mvars for the prior year (as defined in M1 and M2).
b. Seasonal peak hour forecast demands in MW and Mvars (as defined in M1 and M2).

M6. The actual and forecast customer demand data reported on either an aggregated or dispersed basis shall:

a. indicate whether the demand data of nonmember entities within an area or Region are included, and

b. address assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and net energy for load.

Full compliance requires items (a) and (b) to be addressed as described in the reporting procedures developed for Measurement M1 of this Standard II.D. Current information on items a) and b) shall be reported to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request (within 30 days). (S1)

M7. Assumptions, methods, and the manner in which uncertainties are addressed in the forecasts of aggregated peak demands and net energy for load shall be provided to the Regions and NERC on request. (S1)

M8. The actual and forecast demand data used in system modeling and reliability analyses (by the entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC) shall be consistent with the actual and forecast demand data provided under this II.D. Standard on Actual and Forecast Demands. (S1)

M9. Customer demands that are included in or part of controllable demand-side management programs, such as interruptible demands and direct control load management, shall be separately provided on an aggregated Regional, subregional, power pool, and individual system basis to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S2)

M10. Forecasts of interruptible demands and direct control load management data shall be provided annually for at least five years and up to ten years into the future, as requested, for summer and winter peak system conditions to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems as specified by the documentation in Standard II.D.S1-S2, M1.

M11. The amount of interruptible demands and direct control load management shall be made known to system operators and security center coordinators on request.

Full compliance requires the reporting of this data to system operators and security center coordinators with 30 days of a request. (S2)

M12. Forecasts shall clearly document how the demand and energy effects of demand-side management programs (such as conservation, time-of-use rates, interruptible demands, and direct control load management) are addressed.

Information detailing how demand-side management measures are addressed in the forecasts of peak demand and annual net energy for load shall be inclueded in the data reporting procedures of Measurement M1 of this Standard II.D.

Documentation on the treatment of demand-side management programs shall be available to NERC on request (within 30 days). (S2)

Guides

G1. System modeling and reliability analyses may be required for more than a five-year period for several reasons including review or comparison of results from previous studies, regulatory requirements, long lead-time facilities (e.g., transmission lines), and government requirements (e.g., construction and/or environmental permits).

G2. Actual and forecast demand data and forecast controllable demand-side management data should be provided on either an aggregated or dispersed basis in an appropriate common format to ensure consistency in reporting and to facilitate use of the data by the entities responsible for the reliability of the interconnected transmission systems, the Regions, and NERC.

G3. Weather normalized data, when provided in addition to actual data, should be identified as such and reconciled as appropriate.

G4. The characteristics of demand-side management programs used in assessing future resource adequacy should generally include:

- consistent program ratings (demand and energy), including seasonal variations
- effect on annual load shape
- availability, effectiveness, and diversity
- contractual arrangements
- expected program duration
- effects (demand and energy) of multiple programs

Introduction

The various components of customer demand respond differently to changes in system voltage and frequency. Seasonal and time-of-day variations may also affect the components and response characteristics of customer demands. Accurate representation of these customer demand characteristics is needed in system modeling since they can have important effects on system reliability.

Standard

S1. Representative frequency and voltage characteristics of customer demands (real and reactive power) required for the analysis of the reliability of the interconnected transmission systems shall be developed and maintained.

Measurements

M1. The entities responsible for the reliability of the interconnected transmission systems, in conjunction with the Regions, shall develop a plan for determining and promoting the accuracy of the representation of customer demands, identify the scope and specificity of the frequency and voltage characteristics of customer demands, and determine the procedures and schedule for data reporting.

Documentation of these customer demand characteristics (dynamic) plans and reporting procedures shall be provided to NERC and the Regions on request. (S1)

M2. The NERC System Dynamics Database Working Group or its successor group(s) shall maintain and publish customer demand characteristics requirements in its "procedural manual" pertaining to the Eastern Interconnection. Similar "procedural manuals" shall be maintained and published by the Western (***WECC***), ERCOT, and Hydro-Québec[1] Interconnections. These procedural manuals shall include plans for determining and promoting the accuracy of the representation of customer demands. (S1)

M3. Load-serving entities shall provide customer demand characteristics to the Regions and those entities responsible for the reliability of the interconnected transmission systems in compliance with the respective procedural manuals for the modeling of portions or all of the four NERC Interconnections: Eastern, Western, ERCOT, and Hydro-Québec.[4] (S1)

[1]Hydro-Québec uses the Procedural Manual of the Eastern Interconnection.

Guides

G1. The representation of customer demands should generally include a combination of constant MVA, constant current, and constant impedance for real and reactive power components and frequency dependence, as appropriate.

G2. Special demand models for significant frequency and voltage dependent customer demands, such as fluorescent lighting or motors, should be provided on request.

G3. Demand characteristics for zones or areas within electric systems or at substation buses should reflect the composition of the demand at those locations.

G4. The voltage and frequency characteristics of customer demands that are used in system models should be representative of seasonal and time-of-day variations, as appropriate.

G5. The representation of customer demand characteristics should be periodically reviewed and field tested, as appropriate, to ensure the accuracy of the demand modeling.

G6. The sensitivity of simulation results to the demand models should be evaluated. High sensitivity demands (e.g., motors and certain substation demands) should generally be represented by more detailed models.

Protection and control systems are essential to the reliable operation of the interconnected transmission networks. They are designed to automatically disconnect components from the transmission network to isolate electrical faults or protect equipment from damage due to voltage, current, or frequency excursions outside of the design capability of the facilities. Control systems are those systems that are designed to automatically adjust or maintain system parameters (voltages, facility loadings, etc.) within pre-defined limits or cause facilities to be disconnected from or connected to the network to maintain the integrity of the overall bulk electric systems.

The objectives for protection and control systems generally include:

- DEPENDABILITY - a measure of certainty to operate when required,
- SECURITY - a measure of certainty not to operate falsely,
- SELECTIVITY - the ability to detect an electrical fault and to affect the least amount of equipment when removing or isolating an electrical fault or protecting equipment from damage, and
- ROBUSTNESS - the ability of a control system to work correctly over the full range of expected steady-state and dynamic system conditions.

A reliable protection and control system requires an appropriate level of protection and control system redundancy. Increased redundancy improves dependability but it can also decrease security through greater complexity and greater exposure to component failure.

Protection and control system reliability is also dependent upon sound testing and maintenance practices. These practices include defining what, when, and how to test equipment calibration and operability, performing preventive maintenance, and expediting the repair of faulty equipment.

Diagnostic tools, such as fault and disturbance recorders, can provide a record of protection and control system performance under various transmission system conditions. These records are often the only means to diagnose protection and control anomalies. Such information is also critical in determining the causes of system disturbances, the sequence of disturbance events, and developing necessary corrective and preventive actions. In some instances, these records provide information about incipient conditions that would lead to future transmission system problems.

Coordination of protection and control systems is vital to the reliability of the transmission networks. The reliability of the transmission network can be jeopardized by unintentional and unexpected automatic control actions or loss of facilities caused by misoperation or uncoordinated protection and control systems. If protection and control systems are not properly coordinated, a system disturbance or contingency event could result in the unexpected loss of multiple facilities. Such unexpected consequences can result in unknowingly operating the electric systems under unreliable conditions including the risk of a blackout, if the event should occur.

The design of protection and control systems must be coordinated with the overall design and operation of the generation and transmission systems. Proper coordination requires an understanding of:

- The characteristics, operation, and behavior of the generation and transmission systems and their protection and control,
- Normal and contingency system conditions, and
- Facility limitations that may be imposed by the protection and control systems.

Coordination requirements are specifically addressed in the areas of communications, data monitoring, reporting, and analysis throughout the **Standards, Measurements, and Guides** under System Protection and Control (III).

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Protection and Control (III) are provided in the following sections:

A. Transmission Protection Systems
B. Transmission Control Devices
C. Generation Control and Protection
D. Underfrequency Load Shedding
E. Undervoltage Load Shedding
F. Special Protection Systems

These **Standards, Measurements, and Guides** shall apply to all protection and control systems necessary to achieve interconnected transmission network performance as described in the Standards on System Adequacy and Security (I) in this report.

Introduction

The goal of transmission protection systems is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network. They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred.

The need for redundancy in protection systems should be based on an evaluation of the system consequences of the failure or misoperation of the protection system and the need to maintain overall system reliability.

Standards

S1. Transmission protection systems shall be provided to ensure the system performance requirements as defined in the I.A. Standards on Transmission Systems and associated Table I.

S2. Transmission protection systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I.

S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.

S4. Transmission protection system maintenance and testing programs shall be developed and implemented.

Measurements

M1. Transmission or protection system owners shall review their transmission protection systems for compliance with the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I. Any non-compliance shall be documented, including a plan for achieving compliance. Documentation of protection system reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S1)

M2. Where redundancy in the protection systems due to single protection system component failures is necessary to meet the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I, the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations. Breaker failure protections need not be duplicated. (S2)

Each Region shall also develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S2)

M3. Each Region shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations. The Regional procedure shall include the following elements:

1. Requirements for monitoring and analysis of all transmission protective device misoperations.
2. Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affect the reliability of the bulk electric systems as specified by the Region.
3. Process for review, follow up, and documentation of corrective action plans for misoperations.
4. Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.
5. Regional definition of misoperations.

Documentation of the Regional procedure shall be maintained and provided to NERC on request (within 30 days). (S3)

M4. Transmission protection system owners shall have a protection system maintenance and testing program in place. This program shall include protection system identification, schedule for protection system testing, and schedule for protection system maintenance.

Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days). (S4)

M5 Transmission protection system owners shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.

Documentation of the misoperation analyses and corrective actions shall be provided to the affected Regions and NERC on request (within 30 days) according to the Regional procedures of Measurement III.A. S3, M3.

Guides

G1. Protection systems should be designed to isolate only the faulted electric system element(s), except in those circumstances where additional elements must be removed from service intentionally to preserve electric system integrity.

G2. Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault.

G3. The relative effects on the interconnected transmission systems of a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters.

G4. Protection systems and their associated maintenance procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling.

G5. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition.

G6. Communications channels required for protection system operation should be either continuously monitored, or automatically or manually tested.

G7. Models used for determining protection settings should take into account significant mutual and zero sequence impedances.

G8. The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance.

G9. Protection and control systems should be functionally tested, when initially placed in service and when modifications are made, to verify the dependability and security aspects of the design.

G10. Protection system applications should be reviewed whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

G11. The protection system testing program should include provisions for relay calibration, functional trip testing, communications system testing, and breaker trip testing.

G12. Generation and transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems.

G13. When two independent protection systems are required, dual circuit breaker trip coils should be considered.

G14. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

G15. Automatic reclosing or single-pole switching of transmission lines should be used where studies indicate enhanced system stability margins are necessary. However, the possible effects on the systems of reclosure into a permanent fault need to be considered.

G16. Protection system applications and settings should not normally limit transmission use.

G17. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible.

Introduction

Certain transmission devices are planned and designed to provide dynamic control of electric system quantities, and are usually employed as solutions to specific system performance issues. They typically involve feedback control mechanisms using power electronics to achieve the desired electric system dynamic response. Examples of such equipment and devices include: HVDC links, active or real power flow control and reactive power compensation devices using power electronics (e.g., unified power flow controllers (UPFCs), static var compensators (SVCs), thyristor-controlled series capacitors (TCSCs), and in some cases mechanically-switched shunt capacitors and reactors.

In planning and designing transmission control devices, it is important to consider their operation within the context of the overall interconnected systems over a variety of operating conditions. These control devices can be used to avoid degradation of system performance and cascading outages of facilities. If not properly designed, the feedback controls of these devices can become unstable during weakened system conditions caused by disturbances, and can lead to modal interactions with other controls in the interconnected systems.

Standard

S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.

Measurements

M1. When planning new or substantially modified transmission control devices, transmission owners shall evaluate the impact of such devices on the reliability of the interconnected transmission systems. The assessment shall include sufficient modeling of the details of the dynamic devices and encompass a variety of contingency system conditions. The assessment results shall be provided to the Regions and NERC on request. (S1)

M2. Transmission owners shall provide transmission control device models and data, suitable for use in system modeling, to the Regions and NERC on request. Preliminary data on these devices shall be provided prior to their in-service dates. Validated models and associated data shall be provided following installation and energization. (S1)

M3. The transmission owners or operators shall document and periodically (at least every five years or as required by changes in system conditions) review the settings and operating strategies of the control devices. Documentation shall be provided to the Regions and NERC on request. (S1)

Guides

G1. Coordinated control strategies for the operation of transmission control devices may require switching surge studies, harmonic analyses, or other special studies.

G2. For HDVC links in parallel with ac lines, supplementary control should be considered so that the HDVC links provide synchronizing and damping power for interconnected generators. Use of HDVC links to stabilize system ac voltages should be considered.

Introduction

Generator excitation and prime mover controls are key elements in ensuring electric system stability and reliability. These controls must be coordinated with generation protection to minimize generator tripping during disturbance-caused abnormal voltage, current, and frequency conditions. Generators are the primary method of electric system dynamic voltage control, and therefore good performance of excitation equipment (exciter, voltage regulator, and, if applicable, power system stabilizer) is essential for electric system stability. Prime mover controls (governors) are the primary method of system frequency regulation.

Generator control and protection must be planned and designed to provide a balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect the generating equipment from damage. Unnecessary generator tripping during a disturbance aggravates the loading conditions on the remaining on-line generators and can lead to a cascading failure of the interconnected electric systems.

Accurate data that describes generator characteristics and capabilities is essential for the studies needed to ensure the reliability of the interconnected electric systems. Protection characteristics and settings affecting electric system reliability must be provided as requested.

Standards

S1. All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator.

S2. Generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

S3. Temporary excursions in voltage, frequency, and real and reactive power output that a generator shall be able to sustain shall be defined and coordinated on a Regional basis.

S4. Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays.

S5. Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

S6. All generation protection system trip misoperations shall be analyzed for cause and corrective action.

S7. Generation protection system maintenance and testing programs shall be developed and implemented.

Measurements

M1. Generation equipment owners shall provide, upon request, the Region and transmission system operator a log that specifies the date, duration, and reason for each period when the generator was not operated in the automatic voltage control mode. The procedures for reporting the data shall address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements. (S1)

M2. When requested by the transmission system operator, the generating equipment owner shall provide a log that specifies the date, duration, and reason for a generator not maintaining the established network voltage schedule or reactive power output. (S2)

M3. The generation equipment owner shall provide the transmission system operator with the tap settings and available ranges for generator step-up and auxiliary transformers. When tap changes are necessary to coordinate with electric system voltage requirements, the transmission system operator shall provide the generation equipment owner with a report that specifies the required tap changes and technical justification for these changes. The procedures for reporting the data shall address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements. (S2)

M4. When requested, generating equipment owners shall provide the Region and transmission system operator with the operating characteristics of any generator's equipment protective relays or controls that may respond to temporary excursions in voltage, frequency, or loading with actions that could lead to tripping of the generator. The more common protective relays include volts per hertz, loss of excitation, underfrequency, overspeed, and backup distance. (S3)

M5. Upon request, generating equipment owners shall provide the Region and transmission system operator with information that describes how generator controls coordinate with the generator's short term capabilities and protective relays. (S4)

M6. Overexcitation limiters, when used, shall be coordinated with the thermal capability of the generator field winding. After allowing temporary field current overload, the limiter shall operate through the automatic ac voltage regulator to reduce field current to the continuous rating. Return to normal ac voltage regulation after current reduction shall be automatic. The overexcitation limiter shall be coordinated with overexcitation protection so that overexcitation protection only operates for failure of the voltage regulator/limiter. (S4)

M7. Upon request, generating equipment owners shall provide the Region or transmission system operator with information that describes the characteristics of the speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance to the extent possible while meeting the safety requirements of the plant. Nonfunctioning or blocked speed/load governor controls shall be reported to the Region and transmission system operator. (S5)

M8. Each Region shall have a process in place for the monitoring, notification, and analysis of all generation protection trip operations. Documentation of protection trip misoperations shall be provided to the affected Regions and NERC on request. (S6)

M9. Generation equipment owners shall have a generation protection system maintenance and testing program in place. Documentation of the implementation of protection system maintenance and testing shall be provided to the appropriate Regions and NERC on request. (S7)

Guides

G1. Power system stabilizers improve damping of generator rotor speed oscillations. They should be applied to a unit where studies have determined the possibility of unit or system instability and where the condition can be improved or corrected by the application of a power system stabilizer. Power system stabilizers should be designed and tuned to have a positive damping effect on local generator oscillations and on inter-area oscillations without deteriorating turbine/generator shaft torsional oscillation damping.

G2. Generators and turbines should be designed and operated so that there is additional reactive power capability that can be automatically supplied to the system during a disturbance.

G3. Generator control and protection should be periodically tested to the extent practical to ensure the generator plant can provide the designed control, and operate without tripping for specified voltage, frequency, and load excursions. Control responses should be checked periodically to validate the model data used in simulation studies.

G4. New or upgraded excitation equipment should consider high initial response, as inherent in brushless or static exciters.

G5. Generator step-up transformer and auxiliary transformers should have tap settings that are coordinated with electric system voltage control requirements and which do not limit maximum use of the reactive capability (lead and lag) of the generators.

G6. Prime mover control (governors) should operate freely to regulate frequency. In the absence of Regional requirements for the speed/load control characteristics, governor droop should generally be set at 5% and total governor deadband (intentional plus unintentional) should generally not exceed +/- 0.06%. These characteristics should in most cases ensure a coordinated and balanced response to grid frequency disturbances. Prime movers operated with valves or gates wide open should control for overspeed/overfrequency.

G7. Prime mover overspeed controls to the extent practical should be designed and adjusted to prevent boiler upsets and trips during partial load rejection characterized by abnormally high system frequency.

G8. Generator voltage regulators to the extent practical should be tuned for fast response to step changes in terminal voltage or voltage reference. It is preferable to run the step change in voltage tests with the generator not connected to the system so as to eliminate the system effects on the generator voltage. Terminal voltage overshoot should generally not exceed 10% for an open circuit step change in voltage test.

G9. New or upgraded excitation equipment to the extent practical should have an exciter ceiling voltage that is generally not less than 1.5 times the rated output field voltage.

G10. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B, and C of the I.A. Standards on Transmission Systems, unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

Introduction

A coordinated automatic underfrequency load shedding (UFLS) program is required to help preserve the security of the generation and interconnected transmission systems during major declining system frequency events. Such a program is essential to minimize the risk of total system collapse, protect generating equipment and transmission facilities against damage, provide for equitable load shedding (interruption of electric supply to customers), and help ensure the overall reliability of the interconnected systems.

Load shedding resulting from a system underfrequency event should be controlled so as to balance generation and customer demand (load), permit rapid restoration of electric service to customer demand that has been interrupted, and when necessary re-establish transmission interconnection ties.

Standards

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measurements

M1. Each Region shall develop, coordinate, and document a Regional UFLS program, which shall include the following:

a. Requirements for coordination of UFLS programs within the subregions, Region, and, where appropriate, among Regions.
b. Design details including size of coordinated load shedding blocks (% of connected load), corresponding frequency set points, intentional delays, related generation protection, tie tripping schemes, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UFLS programs.
c. A Regional UFLS program database. This database shall be updated as specified in the Regional program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.
d. Technical assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This technical assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:

1. A review of the frequency set points and timing, and
2. Dynamic simulation of possible disturbance that cause the Region or portions of the Region to experience the largest imbalance between demand (load) and generation.

e. Determination, as appropriate, of maintenance, testing, and calibration requirements by member systems.

Documentation of each Region's UFLS program and its database information shall be current and provided to NERC on request (within 30 days).

Documentation of the current technical assessment of the UFLS program shall also be provided to NERC on request (within 30 days). (S1)

M2. Those entities owning or operating an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements as specified in Measurement M1. Such entities shall provide and annually update their UFLS data as necessary for the Region to maintain and update and UFLS program as specified in Measurement M1.

The documentation of an entity's UFLS program shall be provided to the Region on request (within 30 days). (S1)

M3. UFLS equipment owners shall have an UFLS equipment maintenance and testing program in place. This program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance.

These programs shall be maintained and documented, and the results of implementation shall be provided to the Regions and NERC on request (within 30 days).

M4. Those entities owning or operating UFLS programs shall analyze and document their UFLS program performance in accordance with Standard III.D. S1-S2, M1, including the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

1. A description of the event including initiating conditions
2. A review of the UFLS set points and tripping times
3. A simulation of the event
4. A summary of the findings

Documentation of the analysis shall be provided to the Regions and NERC on request 90 days after the system event.

Guides

G1. The UFLS programs should occur in steps related to frequency or rate of frequency decay as determined from system simulation studies. These studies are critical to coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration.

G2. The UFLS programs should be coordinated with generation protection and control, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control.

G3. The technical assessment of UFLS programs should include reviews of system design and dynamic simulations of disturbances that would cause the largest expected imbalances between customer demand and generation. Both peak and off-peak system demand levels should be considered. The assessments should predict voltage and power transients at a widespread number of locations as well as the rate of frequency decline, and should reflect the operation of underfrequency sensing devices. Potential system separation points and resulting system islands should be determined.

G4. Except for qualified automatic isolation plans, the opening of transmission interconnections by underfrequency relaying should be considered only after the coordinated load shedding program has failed to arrest system frequency decline and intolerable system conditions exist.

G5. A generation-deficient entity may establish an automatic islanding plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the transmission systems. This islanding plan may be used only if it complies with the Regional UFLS program and leaves the remaining interconnected bulk electric systems intact, in demand and generation balance, and with no unacceptable high voltages.

G6. In cases where area isolation with a large surplus of generation compared to demand can be anticipated, automatic generator tripping or other remedial measures should be considered to prevent excessive high frequency and resultant uncontrolled generator tripping and equipment damage.

G7. UFLS relay settings and the underfrequency protection of generating units as well as any other manual or automatic actions that can be expected to occur under conditions of frequency decline should be coordinated.

G8. The UFLS program should be separate, to the extent possible, from manual load shedding schemes such that the same loads are not shed by both schemes.

G9. Generator underfrequency protection should not operate until the UFLS programs have operated and failed to maintain the system frequency at an operable level. This sequence of operation is necessary both to limit the amount of load shedding required and to help the systems avoid a complete collapse. Where this sequence is not possible, UFLS programs should consider and compensate for any generator whose underfrequency protection is required to operate before a portion of the UFLS program.

G10. Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated.

If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability.

If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

G11. Where the UFLS program fails to arrest frequency decline, generators may be isolated with local load to minimize loss of generation and enable timely system restoration.

Introduction

Electric systems that experience heavy loadings on transmission facilities with limited reactive power control can be vulnerable to voltage instability. Such instability can cause tripping of generators and transmission facilities resulting in loss of customer demand as well as system collapse. Since voltage collapse can occur suddenly, there may not be sufficient time for operator actions to stabilize the systems. Therefore, a load shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse.

It is imperative that undervoltage relays be coordinated with other system protection and control devices used to interrupt electric supply to customers.

Standards

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.

Measurements

M1. Those entities owning or operating UVLS programs shall coordinate and document their UVLS programs including descriptions of the following:

a. Coordination of UVLS programs within the subregions, the Region, and, where appropriate, among Regions.

b. Coordination of UVLS programs with generation protection and control, UFLS programs, Regional load restoration programs, and transmission protection and control programs.

c. Design details including size of customer demand (load) blocks (% of connected load), corresponding voltage set points, relay and breaker operating times, intentional delays, related generation protection, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UVLS programs.

Documentation of the UVLS programs shall be provided to the appropriate Regions and NERC on request. (S1, S2)

M2. Those entities owning or operating UVLS programs shall ensure that their programs are consistent with any Regional UVLS programs and that exist including automatically shedding load in the amounts and at locations, voltages, rates, and times consistent with any Regional requirements. (S1)

M3. Each Region shall maintain and annually update an UVLS program database. This database shall include sufficient information to model the UVLS program in dynamic simulations of the interconnected transmission systems. (S1)

M4. Those entities owning or operating UVLS programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of its UVLS program. Documentation of the UVLS technical assessment shall be provided to the appropriate Regions and NERC on request. (S1)

M5. Those entities owning or operating UVLS programs shall have a maintenance program to test and calibrate their UVLS relays to ensure accuracy and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the appropriate Regions and NERC on request. (S1)

M6. Those entities owning or operating an UVLS program shall analyze and document all system undervoltage events below the initiating set points of their UVLS programs. Documentation of the analysis shall be provided to the appropriate Regions and NERC on request. (S1)

Guides

G1. UVLS programs should be coordinated with other system protection and control programs (e.g., timing of line reclosing, tap changing, overexcitation limiting, capacitor bank switching, and other automatic switching schemes).

G2. Automatic UVLS programs should be coordinated with manual load shedding programs.

G3. Manual load shedding programs should not include, to the extent possible, customer demand that is part of an automatic UVLS program.

G4. Assessments of UVLS programs should include system dynamic simulations that represent generator overexcitation limiters, load restoration dynamics (tap changing, motor dynamics), and shunt compensation switching.

G5. Plans to shed load automatically should be examined to determine if acceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated.

If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability.

If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

Introduction

A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions, include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings.

The use of an SPS is an acceptable practice to meet the system performance requirements as defined under Categories A, B, or C of Table I of the I.A. Standards on Transmission Systems. Electric systems that rely on an SPS to meet the performance levels specified by the **NERC Planning Standards** must ensure that the SPS is highly reliable.

Examples of SPS misoperation include, but are not limited to, the following:

1. The SPS does not operate as intended.
2. The SPS fails to operate when required.
3. The SPS operates when not required.

Standards

S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.

S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A. Standards on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.

S3. SPS installations shall be coordinated with other protection and control systems.

S4. All SPS misoperations shall be analyzed for cause and corrective action.

S5. SPS maintenance and testing programs shall be developed and implemented.

Measurements

M1. Each Region whose members use or are planning to use an SPS shall have a documented Regional review procedure to ensure the SPS complies with Regional criteria and guides and **NERC Planning Standards**. The Regional review procedure shall include:

1. Description of the process for submitting a proposed SPS for Regional review.
2. Requirements to provide data that describes design, operation, and modeling of an SPS.
3. Requirements to demonstrate that the SPS design will meet above SPS Standards S1 and S2.
4. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional emergency procedures.
5. Regional definition of misoperation.
6. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.
7. Identification of the Regional group responsible for the Region's review procedure and the process for Regional approval of the procedure.
8. Determination, as appropriate, of maintenance and testing requirements.

Documentation of the Regional SPS review procedure shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3, S4)

M2. A Region that has a member with an SPS installed shall maintain an SPS database. The database shall include the following types of information:

1. Design Objectives – Contingencies and system conditions for which the SPS was designed,
2. Operation – The actions taken by the SPS in response to disturbance conditions, and
3. Modeling – Information on detection logic or relay settings that control operation of the SPS.

Documentation of the Regional database or the information therein shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3)

M3. A Region shall assess the operation, coordination, and effectiveness of all SPSs installed in the Region at least once every five years for compliance with NERC Planning Standards and Regional criteria. The Regions shall provide either a summary report or a detailed report of this assessment to affected Regions or NERC, on request (within 30 days). The documentation of the Regional SPS assessment shall include the following elements:

1. Identification of group conducting the assessment and the date the assessment was performed.
2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.

3. Identification of SPSs that were found not to comply with NERC Planning Standards and Regional criteria.
4. Discussion of any coordination problems found between an SPS and other protection and control systems.
5. Provide corrective action plans for non-compliant SPSs. (S1, S2, S3)

M4. SPS owners shall maintain a list of and provide data for existing and proposed SPSs as defined in Measurement III.F. S1-S3, M2. New or functionally modified SPSs shall be reviewed in accordance with the Regional procedures as defined in Measurement III.F. S1-S4, M1 prior to being placed in service.

Documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Planning Standards and Regional criteria shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3)

M5. SPS owners shall analyze SPS operations and maintain a record of all misoperations in accordance with Regional procedures in Measurement III.F. S1-S4, M1. Corrective actions shall be taken to avoid future misoperations.

Documentation of the misoperation analyses and the corrective action plans shall be provided to the affected Regions and NERC, on request (within 90 days). (S4)

M6. SPS owners shall have an SPS maintenance and testing program in place. This program shall include the SPS identification, summary of test procedures, frequency of testing, and frequency of maintenance. Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days). (S5)

Guides

G1. Complete redundancy should be considered in the design of an SPS with diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational.

G2. No identifiable common mode events should result in the coincident failure of two or more SPS components.

G3. An SPS should be designed to operate only for conditions that require specific protective or control actions.

G4. As system conditions change, an SPS should be disarmed to the extent that its use is unnecessary.

G5. SPSs should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling. Test devices or switches should be used to eliminate the necessity for removing or disconnecting wires during testing.

G6. The design of SPSs both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance. Test facilities and test procedures should be designed such that they do not compromise the independence of redundant SPS groups.

G7. SPSs that rely on circuit breakers to accomplish corrective actions should as a minimum use separate trip coils and separately fused dc control voltages.

A blackout is a condition where a major portion or all of an electrical network is de-energized resulting in loss of electric supply to a portion or all of that network's customer demand. Blackouts will generally take place under two typical scenarios:

- Dynamic instability, and
- Steady-state overloads and/or voltage collapse.

Blackouts are possible at all loading levels and all times in the year. Changing generation patterns, scheduled transmission outages, off-peak loadings resulting from operations of pumped storage units, storms, and rapid weather changes among other reasons can all lead to blackouts. Systems must always be alert to changing parameters that have the potential for blackouts.

Actions required for system restoration include identifying resources that will likely be needed during restoration, determining their relationship with each other, and training personnel in their proper application. Actual testing of the use of these strategies is seldom practical. Simulation testing of restoration plan elements or the overall plan are essential preparations toward readiness for implementation on short notice.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Restoration (IV) are provided in the following sections:

A. System Blackstart Capability
B. Automatic Restoration of Load

These **Standards, Measurements, and Guides** address only two aspects of an overall coordinated system restoration plan. From a planning standpoint, it is critical that any overall system restoration plans include adequate generating units with system blackstart capability. It is also important that adequate facilities are planned for the interconnected transmission systems to accommodate the special requirements of system restoration plans such as switching and sectionalizing strategies, station batteries for dc loads, coordination with under-frequency and undervoltage load shedding programs and Regional or area load restoration plans, and facilities for adequate communications.

Automatic restoration of load following a blackout helps to minimize the duration of interruption of electric service to customer demands. However, these automatic systems must be coordinated with other Regional load restoration activities and included in the components of overall system restoration plans.

Introduction

Following the complete loss of system generation (blackout), it will be necessary to establish initial generation that can supply a source of electric power to other system generation and begin system restoration. These initiating generators are referred to as system blackstart generators. They must be able to self-start without any source of off-site electric power and maintain adequate voltage and frequency while energizing isolated transmission facilities and auxiliary loads of other generators. Generators that can safely reject load down to their auxiliary load are another form of blackstart generator that can aid system restoration.

From a planning perspective, a system blackstart capability plan is necessary to ensure that the quantity and location of system blackstart generators are sufficient and that they can perform their expected functions as specified in overall coordinated Regional system restoration plans.

Standards

S1. A coordinated system blackstart capability plan shall be established, maintained, and verified through analysis indicating how system blackstart generating units will perform their intended functions as required in system restoration plans. Such blackstart capability plans shall include coordination within and among Regions as appropriate.

S2. Each blackstart generating unit shall be tested to verify that it can be started and operated without being connected to the system.

Measurements

M1. Each Region shall establish and maintain a system blackstart capability plan that shall be coordinated, as appropriate, with the blackstart capability plans of neighboring Regions. Documentation of system blackstart capability plans shall be provided to NERC on request. (S1)

M2. Regions shall maintain a record of all system blackstart generators within their respective areas and update such records on an annual basis. The record shall include the name, location, MW capacity, type of unit, date of test, and starting method of each system blackstart generating unit. (S1)

M3. The owner or operator of each system blackstart generating unit shall demonstrate at least every five years, through simulation or testing, that the unit can perform its intended functions as required in the system restoration plan. Documentation of the analysis shall be provided to the Region and NERC on request. (S1)

M4. The results of periodic tests of the startup and operation of each system blackstart generating unit shall be documented and provided to the Region and NERC on request. (S2)

M5. Each Region shall verify that the number, size, and location of system blackstart generating units are sufficient to meet system restoration plan expectations. (S1)

Guides

G1. Analyses should ensure that a system blackstart generating unit is capable of maintaining adequate regulation of voltage and frequency.

G2. Analyses should include evaluation of blackstart generator protection and control systems during the abnormal conditions that will exist during system restoration.

G3. Actual physical testing of system blackstart generating unit procedures should be performed where practical or feasible.

G4. When limited energy resources (e.g., hydro, pumped storage hydro, compressed air) are used for blackstart, the system blackstart capability plan timing considerations should include a range of limiting energy conditions.

References

Introduction

If properly coordinated and implemented, automatic restoration of load can be useful to minimize the duration of interruption of electric service to customer demands. However, care must be taken to ensure that automatic restoration of load does not impede restoration of the interconnected bulk electric systems.

After automatic load shedding (by either underfrequency or undervoltage relays) has occurred, use of automatic restoration of load after the electric systems have recovered sufficiently (systems stabilized, frequency near nominal, and voltages within appropriate limits) can speed the reenergization of customer demands and minimize delays in restoring the electric systems.

Standard

S1. Automatic load restoration programs shall be coordinated and in compliance with Regional load restoration programs. These automatic load restoration programs shall be designed to avoid recreating electric system underfrequencies or undervoltages, overloading transmission facilities, or delaying the restoration of system facilities and interconnection tie lines to neighboring systems.

Measurements

M1. Those entities owning or operating an automatic load restoration program shall coordinate, document, review, and implement their programs in compliance with Regional programs for load restoration. Documentation of automatic load restoration programs shall be provided to the appropriate Regions and NERC on request. (S1)

M2. Documentation of automatic load restoration programs shall include:

a. A description of how load restoration is coordinated with underfrequency and undervoltage load shedding programs within the Region and, where appropriate, among Regions.

b. Automatic load restoration design details including size of coordinated load restoration blocks (% of connected load), corresponding frequency or voltage set points, and operating sequence (including relay and breaker operating times and intentional delays). (S1)

M3. Each Region shall maintain and annually update an automatic load restoration program database. This database shall include sufficient information to model the automatic load restoration programs in dynamic simulations of the interconnected transmission systems. (S1)

References

M4. Those entities owning or operating an automatic load restoration program shall conduct and document a technical assessment of the effectiveness of the design and implementation of their programs including their relationship to underfrequency and undervoltage load shedding programs in the Region. Documentation of the technical assessments of automatic load restoration programs shall be available to the appropriate Regions and NERC on request. (S1)

M5. Those entities owning or operating automatic load restoration programs shall have a maintenance program to test and calibrate the automatic load restoration relays to ensure accurate and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the appropriate Regions and NERC on request. (S1)

Guides

G1. Relays installed to restore load automatically should be set with varying and relatively long time delays, except for that portion of the automatic load restoration, if any, that is designed to protect against frequency overshoot.

G2. The design of automatic load restoration programs should consider the system effects of reenergizing large blocks of customer demand.

G3. Major interconnection tie lines should generally be restored to service before automatic restoration of load is implemented.

References

The references in this section are provided as background information for the users of the **NERC Planning Standards**. This list is comprised of recommendations from the various members of the NERC Engineering Committee's subgroups that participated in the development of the **NERC Planning Standards**.

Except for NERC references, the references in the following list have not been reviewed or endorsed by NERC or any of its subgroups. However, these references should aid the reader who wants an understanding of specific technical areas addressed in the **NERC Planning Standards**.

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III.F Special Protection Systems

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The NERC Planning Standards were approved by the NERC BOT 1997, 2001, 2002
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WESTERN ELECTRICITY COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

PART II

WESTERN ELECTRICITY COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

INTRODUCTION

The Western Electricity Coordinating Council was established to promote the reliable operation of the interconnected bulk power system by the coordination of planning and operation of generating and interconnected transmission facilities.

The Planning Coordination Committee assigned the Reliability Subcommittee the task of developing an Adequacy of Supply Assessment Methodology. This document establishes the policy for conducting power supply assessments using the methodology developed by the Reliability Subcommittee. This policy shall be periodically reviewed and revised as experience indicates.

PURPOSE OF POWER SUPPLY ASSESSMENT

To ensure the reliability of the interconnected bulk electric system, it is necessary to assess both the security and the adequacy of the overall Western Interconnection. This document is focused on the portion of the assessment dealing with the adequacy of power supply. As electric industry restructuring has begun to break apart the traditional model of the vertically integrated utility, the responsibility for maintaining the adequacy of the power supply is moving toward market mechanisms. Though there may not be specific entities entrusted to plan for adequate resources, there exists a need to assess whether projected resources will be sufficient to reliably meet demand. Such information will allow regulators and policy makers to anticipate potential shortfalls so that determinations can be made as to whether impediments or insufficient incentives exist in the market.

It is not the intent of an adequacy assessment to replace the market, create sanctionable criteria or anticipate future energy prices. Its purpose is to project whether enough resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths. Such an assessment is required to comply with the NERC Planning Standards. These standards require that each region perform a regional assessment of existing and planned (forecast) adequacy of the bulk electric system.

It is recognized that it is impossible to provide 100% adequacy of power supply. It is the purpose of this document to establish a uniform policy for assessing the adequacy of installed and planned resources within the WECC region for the purposes of reporting within the Council, and to outside agencies. The assessments shall cover a period encompassing the next 5 years.

ASSESSMENT METHODOLOGY

The Power Supply Assessment Methodology shall be developed and maintained by the Reliability Subcommittee. Adequacy of supply may be defined and measured in terms of generating reserve margins and transmission limitations between load and resource areas and/or based on probabilistic methods. Appropriate technical tools shall be developed and utilized in conducting the assessments. The assessments shall account for diversity of load and generation, and account for transmission constraints between load and resource areas.

DATA REQUIREMENTS

To aid WECC in assessing resource adequacy, the following information shall be provided by the WECC members:

Load Forecasts

- Electricity demand and energy forecasts, including uncertainties
  - Variations due to weather
  - Variations due to other factors affecting forecasts

Demand Side Management (DSM) Programs

- Existing and planned demand-side management programs
  - Direct controlled interruptible loads
  - Aggregate effects of multiple DSM programs

Resource Information

- Supply-side resource characteristics, including uncertainties
  - Consistent generator unit ratings, including seasonal variations and environmental considerations affecting hydro and thermal units
  - Availability of generating units
  - Fuel type

Transmission Information

- Capabilities, availability of transmission capacity, and other uncertainties

REPORTING OF POWER SUPPLY ADEQUACY

The assessment of generating reserve margins and transmission limitations between load and resource areas as well as probabilities of supplying expected load levels, accounting for uncertainties, shall be developed and the results reported on a seasonal basis. The assessment shall be consistent with the requirement for maintaining operating reserves as defined in the *WECC Minimum Operating Reliability Criteria* and NERC Operating Policies.

Approved by Reliability Subcommittee June 16, 2000
Approved by Planning Coordination Committee June 30, 2000
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WESTERN ELECTRICITY COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

PART III

WESTERN ELECTRICITY COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

TABLE OF CONTENTS

WESTERN ELECTRICITY COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

INTRODUCTION

The reliable operation of the Western Interconnection requires that all entities comply with the *Western Electricity Coordinating Council (WECC) Minimum Operating Reliability Criteria* (hereafter referred to as MORC). The MORC shall apply to system operation under all conditions, even when facilities required for secure and reliable operation have been delayed or forced out of service.

On a continuing basis, the North American Electric Reliability Council (NERC), through its Operating Committee, establishes, reviews, and updates operating criteria to be followed by individual entities, pools, coordinated areas and reliability councils. All entities, WECC members and nonmembers, shall operate in accordance with the NERC or WECC Reliability Criteria, whichever is more specific or stringent. In addition to complying with the MORC, all entities shall comply with all WECC Operating Policies and Procedures which are included in the *WECC Operating Committee Handbook*. The WECC shall periodically review and revise MORC in accordance with the guidelines set forth in the *WECC Reliability Criteria Part V – Process for Developing and Approving WECC Standards*.

NERC has identified control areas as the primary entities responsible for ensuring the secure and reliable operation of the interconnected power system. Secure and reliable operation can only result from all entities complying with a consistent set of operating criteria. To this end it is imperative for all control areas in the Western Interconnection to be members of the WECC.

Entities such as Independent System Operators and Area Reliability Coordinators may assume some of the responsibilities that control areas have traditionally held. It is also imperative that these entities be WECC members and comply with all operating reliability criteria which apply to control areas.

The MORC and all WECC Operating Policies and Procedures apply to all entities unless expressly stated as applying only to a particular entity. It is imperative that all entities equitably share the various responsibilities to maintain reliability. Examples of equitably sharing reliability responsibilities include, but are not limited to:

- proper coordination and communication of interchange schedules,
- participation in coordinated underfrequency load shedding programs,
- participation in the unscheduled flow mitigation plan,
- providing appropriate levels of power system stabilizers, and
- maintaining appropriate governor droop settings.

The MORC is divided into sections corresponding to the NERC Policies. Also included are the coordination requirements necessary to achieve the objectives set forth in these Criteria. It is emphasized that these are minimum criteria related to operating reliability or procedures which are necessary for the secure and reliable operation of the interconnected power system. More specific and more stringent operating reliability criteria may be developed by each individual entity, pool, and/or coordinated area within the WECC.

Section 1 - Generation Control and Performance

All generation shall be operated to achieve the highest practical degree of service reliability. Appropriate remedial action will be taken promptly to eliminate any abnormal conditions which jeopardize secure and reliable operation.

A. Operating Reserve

The reliable operation of the interconnected power system requires that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies. This generating capacity is necessary to:

- supply requirements for load variations.
- replace generating capacity and energy lost due to forced outages of generation or transmission equipment.
- meet on-demand obligations.
- replace energy lost due to curtailment of interruptible imports.

1. **Minimum operating reserve.** Each control area shall maintain minimum operating reserve which is the sum of the following:

    (a) **Regulating reserve.** Sufficient spinning reserve, immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's *Control Performance Criteria.*

    Plus (b) **Contingency reserve.** An amount of spinning and nonspinning reserve, sufficient to meet the Disturbance Control Standard as defined in 1.E.2(a). This Contingency Reserve shall be at least the greater of:

    (1) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency (at least half of which must be spinning reserve); or

    (2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation (at least half of which must be spinning reserve).

    For generation-based reserves, only the amount of unloaded generating capacity that can be loaded within ten minutes of notification can be considered as reserve.

Plus (c) **Additional reserve for interruptible imports.** An amount of reserve, which can be made effective within ten minutes following notification, equal to interruptible imports.

Plus (d) **Additional reserve for on-demand obligations.** An amount of reserve, which can be made effective within ten minutes following notification, equal to on-demand obligations to other entities or control areas.

2. **Acceptable types of nonspinning reserve.** The nonspinning reserve obligations identified in A.1.b, A.1.c, and A.1.d, if any, can be met by use of the following:

   (a) load which can be interrupted within 10 minutes of notification

   (b) interruptible exports

   (c) on-demand rights from other entities or control areas

   (d) spinning reserve in excess of requirements in A.1.a and A.1.b

   (e) off-line generation which qualifies as nonspinning reserve (see definition)

3. **Knowledge of operating reserve.** Operating reserves shall be calculated such that the amount available which can be fully activated in the next ten minutes will be known at all times.

4. **Restoration of operating reserve.** After the occurrence of any event necessitating the use of operating reserve, that reserve shall be restored as promptly as practicable. The time taken to restore reserves shall not exceed 60 minutes.

5. **Analysis of islanding potential.** Each entity or coordinated group of entities shall analyze its potential for islanding in total or in part from interconnected resources at least every three years and shall maintain appropriate additional operating reserve for such contingencies or, if such is impractical, its load and generation shall be balanced by other appropriate measures.

6. **Sharing operating reserves.** Under written agreement, the operating reserve requirements of two or more control areas may be combined or shared, providing that such combination, considered as a single control area, meets the obligations of paragraph A.1. Similarly, arrangements may be made whereby one control area supplies a portion of another's operating reserve, provided that such capacity can be made available in such a manner that both meet the requirements of paragraph A.1. A firm transmission path must be available and reserved for the transmission of these operating reserves from the control area supplying the reserves to the control area calling on them.

7. **Operating reserve distribution.** Prudent operating judgment shall be exercised in distributing operating reserve, taking into account effective use of capacity in an emergency, time required to be effective, transmission

limitations, and local area requirements. Spinning reserve should be distributed to maximize the effectiveness of governor action.

8. **Review of contingencies.** To determine the amount of operating reserve required, contingencies shall be frequently reviewed and the most severe contingency designated.

B. Automatic Generation Control

Each control area shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and interchange schedules to its load. It shall also provide its proper contribution to Interconnection frequency regulation.

1. **Inclusion in control area.** Each entity operating transmission, generation, or distribution facilities shall either operate a control area or make arrangements to be included in a control area operated by another entity. All generation, transmission, and load operating within the Western Interconnection shall be included within the metered boundaries of a WECC control area. Control areas are ultimately responsible for ensuring that the total generation is properly matched to total load in the Interconnection.

2. **AGC.** Prudent operating judgment shall be exercised in distributing control among generating units. AGC shall remain in operation as much of the time as possible. As described in the *WECC Guidelines for Suspending Automatic Generation Control* in the *WECC Operating Committee Handbook*, AGC suspension should be considered when AGC equipment has failed or if system conditions could be worsened by AGC.

3. **Familiarity with AGC equipment.** Control center operating personnel must be thoroughly familiar with AGC equipment and be trained to take necessary corrective action when equipment fails or misoperates. If primary AGC has become inoperative, backup AGC or manual control shall be used to adjust generation to maintain schedules.

4. **Data scan rates for ACE.** It is recommended that the periodicity of data acquisition for and calculation of ACE should be no greater than four seconds.

C. Frequency Response and Bias

1. **Frequency bias setting.** The frequency bias shall be set as close as possible to the control area's natural frequency response characteristic. In no case shall the annual frequency bias or the monthly average frequency bias be set at a value of less than 1% of the estimated control area annual peak load per 0.1 Hz change in frequency.

2. **Governors.** To provide an equitable and coordinated system response to load/generation imbalances, governor droop shall be set at 5%. Governors shall not be operated with excessive deadbands, and governors shall not be blocked unless required by regulatory mandates.

3. **Tie-line bias.** Each control area shall operate its AGC on tie-line frequency bias mode, unless such operation is adverse to system or Interconnection reliability.

D. Time Control

1. **Time error.** Control areas shall assist in maintaining frequency at or as near 60.0 Hz as possible and shall cooperate in making any necessary time corrections per the *WECC Procedure for Time Error Control*. The amount of continuous time error contribution is a function of control area time error bias, inadvertent interchange accumulation, and the time error.

2. **Maintain standards for frequency offset.** Control areas shall cooperate in maintaining standards established by the NERC Operating Committee for frequency offset to make time corrections manually.

3. **Time error correction notice and commencement.** Time error corrections shall start and end on the hour or half hour, and notice shall be given at least twenty minutes before the time error correction is to start or stop. Time error corrections shall be made at the same rate by all control areas.

4. **Calibration of time and frequency devices.** Each control area shall at least annually check and calibrate its time error and frequency devices against a common reference.

E. Control Performance

1. **Continuous monitoring.** Each control area shall monitor its control performance on a continuous basis against two Standards: CPS1 and CPS2.

   (a) **Control performance standard (CPS1).** Over a year, the average of the clock-minute averages of a control area's ACE divided by -10β (β is control area frequency bias) times the corresponding clock-minute averages of Interconnection's frequency error shall be less than a specific limit. This limit, ε, is a constant derived from a targeted frequency bound reviewed and set as necessary by the NERC Performance Subcommittee.

   (b) **Control performance standard (CPS2).** The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See NERC's *Performance Standard Training Document*, Section B.1.1.2 for the methods for calculating L_{10}.

   (c) **Control performance standard (CPS) compliance.** Each control area shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90%.

2. **Disturbance conditions.** In addition to CPS1 and CPS2, the Disturbance Control Standard shall be used by each control area or reserve sharing group to

monitor control performance during recovery from disturbance conditions (see the *Performance Standard Training Document*, Section B.2):

(a) **Disturbance Control Standard.** Following the start of a disturbance, the ACE must return either to zero or to its pre-disturbance level within the time specified in the Disturbance Control Standard currently in effect in NERC Policy 1.

(b) **Disturbance control standard compliance.** Each control area or reserve sharing group shall meet the Disturbance Control Standard (DCS) 100% of the time for reportable disturbances.

(c) **Reportable disturbance reporting threshold.** Each control area or reserve sharing group shall include events that cause its Area Control Error (ACE) to change by at least 35% of the maximum loss generation that would result from a single contingency.

(d) **Average percent recovery.** For each reportable disturbance, the control area(s) with a MW loss or participating in the response, such as through operating reserve obligations or through a reserve sharing group, shall calculate an Average Percent Recovery. A copy of the control area's calculations, ACE chart, and Net Tie Deviation from Schedule chart shall be submitted to the NERC Regional Performance Subcommittee representative not later than 10 calendar days after the reportable disturbance.

(e) **Contingency reserve adjustment factor.** The WECC Performance Work Group (PWG) shall determine the Contingency Reserve Adjustment Factor for each control area no later than April 20, July 20, September 20, and January 20 for the previous quarter. The local PWG representatives shall allocate the factor among control areas that are members of reserve sharing groups according to the allocation methods developed by the group.

(f) **Operating reserve for control areas and reserve sharing groups.** Minimum Operating Reserve shall be increased by the Contingency Reserve Adjustment Factor. The WECC Performance Work Group shall monitor the compliance of each control area and reserve sharing group for carrying the minimum required operating reserve.

3. **ACE values.** The ACE used to determine compliance to the Control Performance Standards shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action.

F. Inadvertent Interchange

1. **Hourly verification.** Each control area shall, through hourly schedule verification and the use of reliable metering equipment, accurately account for inadvertent interchange.

2. **Common metering.** Each control area interconnection point shall be equipped with a common kWh meter, with readings provided hourly at the control centers of both areas.

3. **Including all interconnections.** All interconnections shall be included in inadvertent interchange accounting. Interchange served through jointly owned facilities and interchange with borderline customers shall be properly taken into account.

G. Control Surveys

1. **Survey purpose.** Periodic surveys of the control performance of the control areas shall be conducted. These surveys reveal control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance.

2. **Surveys.** The control areas in the Western Interconnection shall perform each of the following surveys, as described in the *NERC Control Performance Criteria Training Document*, when called for by the NERC Performance Subcommittee:

   (a) **AIE survey.** Area Interchange Error survey to determine the control area's interchange error(s) due to equipment failures, improper scheduling operations, or improper AGC performance.

   (b) **FRC survey.** Area Frequency Response Characteristic survey to determine the control area's response to changes in system frequency.

   (c) **CPC survey.** Control Performance Criteria survey to monitor the control area's control performance during normal and disturbance situations.

H. Control and Monitoring Equipment

1. **Tie line bias control equipment.** Each control area shall use accurate and reliable automatic tie line bias control equipment as a means of continuously balancing actual net interchange with scheduled net interchange, plus or minus its frequency bias obligation and automatic time error correction. The power flow and ACE signals that are transmitted for regulation service shall not be filtered prior to transmission except for anti-aliasing filtering of tie lines.

2. **Tie flows in ACE calculation.** To achieve accurate control, each control area shall include all of its interconnecting ties in its ACE calculation. Common interchange metering equipment at agreed upon terminals shall be used by adjacent control areas.

3. **Control checks made each hour.** Actual interchange shall be verified each hour by each control area using tie line kWh meters to determine regulating performance. Adjacent control areas shall use the same MWh value for each common interchange point. Control settings shall be adjusted to compensate for any equipment error until equipment malfunction can be corrected.

I. Backup Power Supply

Under emergency conditions, adequate and reliable emergency or backup power supply must be available to provide for generating equipment protection and continuous operation of those facilities required for restoration of the system to normal operation.

1. **Safe shut-down power.** Emergency or auxiliary power supply shall be provided for the safe shutdown of thermal generating units when completely isolated from a power source.
2. **Reliable start-up power.** A reliable and adequate source of start-up power for generating units shall be provided. Where sources are remote from the generating unit, standing instructions shall be issued to expedite start up.
3. **Black start capability for critical generating units.** All control areas must identify critical generating units and ensure provision of "black start" capability for these units if appropriate arrangements have not been made to receive off-system power for the purpose of system restoration.
4. **Testing.** Emergency or backup power supplies shall be periodically tested to ensure their availability and performance.

Section 2 - Transmission

The interconnected power system shall be operated to achieve the highest practical degree of service reliability. Appropriate remedial action shall be taken promptly to eliminate any abnormal conditions which jeopardize secure and reliable operation.

A. Transmission Operations

1. **Basic criteria.** The interconnected power system shall be operated at all times so that general system instability, uncontrolled separation, cascading outages, or voltage collapse will not occur as a result of any single contingency or multiple contingencies of sufficiently high likelihood (as defined below). Entities must ensure this criteria is met under all system conditions including equipment out of service, equipment derates or modifications, unusual loads and resource patterns, and abnormal power flow conditions. A single contingency means the loss of a single system element, however, the outage of multiple system elements should be treated as a single contingency if caused by a single event of sufficiently high likelihood. When experience proves that an outage involving multiple system elements, AC or DC, occurs more than once during the previous three years and causes, on other systems, loss of load, loss of generation rated greater than 100 MW or cascading outages, it shall be treated as a single contingency.

When it is agreed that a disturbance on specific facilities occurs more often than should be reasonably expected and results in an undue burden on the transmission system, the owners of the facilities shall take measures to reduce the frequency of occurrence of the disturbance, and cooperate with other entities in taking measures to reduce the effects of such disturbance.

Continuity of service to load is the primary objective of the *Minimum Operating Reliability Criteria*. Preservation of interconnections during disturbances is a secondary objective except when preservation of interconnections will minimize the magnitude of load interruption or will expedite restoration of service to load.

It is undesirable for the loss of load to exceed the amount of load designed to be tripped. This applies to all levels of system underfrequency load shedding programs, undervoltage load tripping schemes or other controlled remedial actions. It applies whether the initiating disturbance occurs within or outside the affected system. Entities may be required to establish maximum import levels to meet these criteria. The necessary operating procedures, equipment, and remedial action schemes shall be in place to prevent unplanned or uncontrolled loss of load or total system shutdown.

2. **Joint reliability procedures.** Where specific transmission issues have been identified, those entities affected by and those entities contributing to the problem shall develop joint procedures for maintaining reliability.

3. **Phase-shifting transformers and other flow altering facilities.** Phase shifting transformers or other facilities, when used to alter power flow through the interconnected power system, shall be operated to control the actual power flow within the limits of the scheduled power flow and the unaltered power flow. In meeting the criteria, a tolerance of two taps on phase shifting transformers and one discrete increment on other noncontinuous controllable devices is permissible provided no other operating criteria are violated. Such power flow altering facilities may be operated to some other criteria provided agreement is reached among the affected parties.

4. **Protective relay reliability.** Relays that have misoperated or are suspected of improper operation shall be promptly removed from service until repaired or correct operation is verified.

B. Voltage and Reactive Control

1. **Maintaining service.** To ensure secure and reliable operation of the interconnected power system, reactive supply and reactive generation shall be properly controlled, adequate reactive reserves shall be provided, and adequate transmission system voltages shall be maintained.

2. **Providing reactive requirements.** Each entity shall provide for the supply of its reactive requirements, including appropriate reactive reserves, and its share of the reactive requirements to support power transfers on interconnecting transmission circuits.

3. **Coordination.** Operating entities shall coordinate the use of voltage control equipment to maintain transmission voltages and reactive flows at optimum levels for system stability within the operating range of electrical equipment. Operating strategies for distribution capacitors and other reactive control equipment shall be coordinated with transmission system requirements.

4. **Transmission lines.** Transmission lines should be kept in service as much as possible. They may be removed from service for voltage control only after studies indicate that system reliability will not be degraded below acceptable levels. The entity responsible for operating such transmission line(s) shall promptly make notification according to the *WECC Procedure for Coordination of Scheduled Outages and Notification of Forced Outages* when removing such facilities from and returning them back to service.

5. **Generators.** Generating units 10 MVA and larger shall be equipped with automatic voltage control equipment. All generating units with automatic voltage control equipment shall normally be operated in voltage control mode. These generating units shall not be operated in other control modes (e.g., constant power factor control) unless authorized to do so by the host control area. The control mode of generating units shall be accurately represented in operating studies.

6. **Automatic voltage control equipment.** Automatic voltage control equipment on generating units, synchronous condensers, and static var compensators shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time. Such voltage control equipment shall operate at voltages specified by the host control area operator.

7. **Power system stabilizers.** Power system stabilizers on generators and synchronous condensers shall be kept in service as much of the time as possible.

8. **Reactive reserves.** Operating entities shall ensure that reactive reserves are adequate to maintain minimum acceptable voltage limits under facility outage conditions. Reactive reserves required for acceptable response to contingencies shall be automatically applied when contingencies occur. Operation of static and dynamic reactive devices shall be coordinated such that static devices are switched in or out of service so that the maximum reactive reserves are maintained on generators, synchronous condensers and other dynamic reactive devices.

9. **Undervoltage load shedding.** Operating entities shall assess the need for and install undervoltage load shedding as required to augment other reactive reserves to protect against voltage collapse and ensure system reliability performance criteria as specified in the WECC Disturbance-Performance Table of Allowable Effect on Other Systems are met during all internal and external outage conditions. The operator shall have written authority to manually shed additional load if necessary to maintain acceptable voltages and/or sufficient reactive margin to protect against voltage collapse.

10. **Switchable devices.** Devices frequently switched to regulate transmission voltage and reactive flow shall be switchable without de-energizing other facilities.

11. **HVDC.** Entities with HVDC transmission facilities should use the reactive capabilities of converter terminal equipment for voltage control.

Section 3 - Interchange

To ensure the secure and reliable operation of the interconnected power system, all entities involved in interchange scheduling shall coordinate and communicate information concerning schedules and schedule changes accurately and timely as detailed in the *WECC Scheduling Procedures for All Entities Involved in Interchange Scheduling.*

A. Interchange

1. **Net schedules.** The net schedule on any control area to control area interconnection or transfer path within a control area shall not exceed the total transfer capability of the transmission facilities.

2. **Transfer capability.** Transmission providers or control areas shall determine normal total transfer capability limits for the delivery and receipt of scheduled interchange. The determination of such total transfer capability limits shall, as far as practicable, take into consideration the effect of power flows through other parallel systems or control areas under both normal operating conditions and with a single contingency outage of the most critical facility.

3. **Schedule confirmation and implementation.** All scheduled transactions shall be confirmed and implemented between or among the control areas involved in such transactions. "Control areas involved" means the control area where the schedule originates, the control area(s) providing transmission service for the transaction, and the control area where the scheduled energy is delivered. If a schedule cannot be confirmed it shall not be implemented.

4. **Schedule verification.** Each Control Area is responsible to have the net scheduled interchange verified with all adjacent Control Areas on an hourly preschedule and real-time basis. This verification may be accomplished through a designated agent. Real-time verification shall take place prior to the start of the ramp.

5. **Schedule changes.** Schedule changes must be coordinated between control areas to ensure that the schedule changes will be executed by all control areas at the same time, in the same amount and at the same rate.

6. **Type of transaction.** Parties providing and receiving the scheduled energy shall agree upon the type of transaction being implemented (firm or interruptible) and the control area(s) and other parties providing the operating reserve for the transaction, and shall make this information available to all control areas involved in the transaction.

7. **Information sharing.** Control areas, pools, coordinated areas or reliability councils shall develop procedures to disseminate information on schedules

which may have an adverse effect on other control areas not involved in making the scheduled power transfer.

8. **Unscheduled flow.** Unscheduled flow is an inherent characteristic of interconnected AC power systems and the mere presence of unscheduled flow on circuits other than those of the scheduled transmission path is not necessarily an indication of a problem in planning or in scheduling practices. WECC transmission paths experiencing significant curtailments as a result of unscheduled flow may be qualified for unscheduled flow relief under the *WECC Unscheduled Flow Reduction Procedure*. All personnel involved in interchange scheduling shall be trained and fully competent in implementing the *WECC Unscheduled Flow Reduction Procedure*.

   The WECC planning process and the *Unscheduled Flow Reduction Procedure* are designed to minimize impact of unscheduled flow for normal system configurations. During abnormal system configurations such as during the restoration period following a major system disturbance, consideration shall be given to the unscheduled flow effects created by schedules and scheduled transmission paths and the reliability coordinator(s) shall ensure that all schedules are arranged such that the effect of unscheduled flow does not cause transfer capability limits to be exceeded on other transmission paths.

   It is unacceptable to rely on opposing unscheduled flow to keep actual flows within the path total transfer capability regardless of whether the path is a transmission element internal to a control area or whether the path is a control area to control area interconnection.

B. Transfer Capability Limit Criteria

The total transfer capability limit is the maximum amount of actual power that can be transferred over direct or parallel transmission elements comprising:

- An interconnection from one control area to another control area; or
- A transfer path within a control area.

The net schedule and prevailing actual power flowing over an interconnection or transfer path within a control area shall not exceed the total transfer capability limit on the interconnection or transfer path.

1. **Operating limits.** No elements within the interconnection shall be scheduled above continuous operating limits. An element is defined as any generating unit, transmission line, transformer, bus, or piece of electrical equipment involved in the transfer of power within an interconnection. At all times the interconnected system shall be operated so neither the net scheduled or actual power transferred over an interconnection or transfer path shall exceed the total transfer capability of that interconnection or transfer path. If the limit is exceeded, immediate action shall be taken to reduce actual flow to within transfer capability limits within 20 minutes for stability limitations and within 30 minutes for thermal limitations.

2. **Stability.** The interconnected power system shall remain stable upon loss of any one single element without system cascading that could result in the successive loss of additional elements. The system voltages shall be within acceptable limits defined in the *NERC/WECC Planning Standards*. If a single event could cause loss of multiple elements, these shall be considered in lieu of a single element outage. This could occur in exceptional cases such as two lines on the same right-of-way next to an airport. In either case, loss of either single or multiple elements should not cause uncontrolled, widespread collapse of the interconnected power system.

3. **System contingency response.** Following the outage and before adjustments can be made:

   (a) No remaining element shall exceed its short-time emergency rating.

   (b) The steady-state system voltages shall be within emergency limits.

The limiting event shall be determined by conducting power flow and stability studies while simulating various operating conditions. These studies shall be updated as system configurations introduce significant changes in the interconnection.

Section 4 - System Coordination

A high degree of coordination is essential within and between the entities, control areas, pools and coordinated areas of the WECC in all phases of operation which can affect the reliability of the interconnected power system.

This section sets forth operating items that require coordination to make certain that the minimum operating reliability criteria contained herein can be realized by the interconnected power system.

A. Monitoring System Conditions

Coordination and communication in the following areas is essential for secure and reliable operation of the interconnected power system.

1. **System conditions.** Loads, generation, transmission line and bulk power transformer loading, voltage, and frequency shall be monitored as required to determine if system operation is within known safe limits under both normal and emergency situations.

2. **Deviations.** The use of automatic equipment to bring immediate attention to important deviations in system operating conditions and to indicate or initiate corrective action shall be implemented.

3. **Remedial action scheme status alarms.** Alarms shall be provided to alert operating personnel regarding the status of remedial action schemes which are under their direct control and impact the reliability and security of interconnected power system operation.

4. **Sharing operational information.** All entities shall, by mutual agreement, provide essential and timely operational information regarding their system

(e.g., line flows, generator status, net interchange schedules at tie points, etc.) to all affected transmission providers and control areas.

5. **Voltage collapse.** Information regarding system problems that could lead to voltage collapse shall be disseminated and operation to alleviate the effects of such severe conditions shall be coordinated.

B. Coordination with Other Entities

1. **Procedures.** Procedures shall be in place for the effective transfer of operating information between control areas, entities, and coordinated groups of entities as necessary to maintain interconnected power system reliability.

2. **Switching operation.** The opening or closing of interconnections between control areas, and the opening or closing of any lines internal to control areas which may affect the operation of the interconnected power system under normal and emergency conditions must be fully coordinated.

3. **Voltage and reactive flows.** Control areas shall coordinate the control of voltage levels and reactive flows during normal and emergency conditions. All operating entities shall assist with their control area's coordination efforts.

4. **Load shedding and restoration.** The shedding and restoration of loads in emergencies must be coordinated as described in detail in Sections 5.D. and 6.C.

5. **Automatic actions.** Any automatic controlled islanding and automatic generator tripping which is necessary to maintain interconnected power system stability under emergency conditions shall be coordinated. All automatic remedial actions (automatic bypass of series compensation, phase shifter runback, opening of lines or transformers, load tripping, etc.) which may impact the interconnected power system, shall be coordinated.

6. **Interconnection capabilities.** Information regarding the operating capabilities of interconnecting facilities between operating entities or control areas shall be exchanged routinely and all operating entities shall coordinate establishment of the operating limitations of these facilities under normal and emergency conditions.

7. **Plans and forecasts.** Information regarding short-term load forecasts, generating capabilities, and schedules of additions or changes in system facilities that could affect interconnected operation shall be routinely disseminated.

8. **System characteristics.** Information regarding system electrical characteristics that affect the operation of the interconnected system, including any significant changes which result from the addition of facilities or modification of existing facilities, shall be routinely disseminated.

9. **Operating reserve.** Information regarding operating reserve policies and procedures shall be routinely disseminated.

10. **Abnormal operating conditions.** Operating entities forced to operate in such a way that a single contingency could result in general system instability, uncontrolled separation, cascading outages, or voltage collapse, shall promptly notify WECC and other affected operating entities via the WECC Communication System.

11. **Notification of system emergencies.** In the event of system emergencies involving loss of any element(s), all affected entities and control areas shall be notified of the extent of the outage and estimated time of restoration. Preliminary emergency outage notification shall be provided via the WECC Communication System as quickly as possible. Restoration information, if not available immediately, shall be provided as soon as practicable.

12. **Notification of noncompliance.** If an operating entity is not able to comply with the condition and term of a particular criterion, it must notify the host control area. The control area operator will notify the WECC who will report the noncompliance to the NERC Operating Committee.

C. Maintenance Coordination

1. **Sharing information.** The security and reliability of the interconnected power system depends upon periodic inspection and adequate maintenance of generators, transmission lines and associated equipment, control equipment, communication equipment, relaying equipment and other system facilities. Entities and coordinated groups of entities shall establish procedures and responsibility for disseminating information on scheduled outages and for coordinating scheduled outages of major facilities which affect the security and reliability of the interconnected power system.

D. System Protection Coordination

Reliable and adequate relaying must be provided to protect and permit maximum utilization of generation, transmission and other system facilities.

1. **Coordination.** Information regarding protective relay systems affecting interconnected operation shall be routinely disseminated and the settings of such relays shall be coordinated with the affected entities.

2. **Reviewing settings.** Relay applications and settings shall be reviewed periodically and adjustments made as needed to meet system requirements.

3. **Testing.** Each operating entity shall periodically test protective relay systems and remedial action schemes which impact the security and reliability of interconnected power system operation.

Section 5 - Emergency Operations

Even though precautionary measures have been developed and utilized, and extensive protective equipment installed, emergencies of varying magnitude do occur on the interconnected power system. These emergencies may be minor in nature and require small, real-time system adjustments, or they may be major and require fast, preplanned action to avoid the cascading loss of generation or transmission lines, uncontrolled separation, and interruption of customer service. All entities are expected to cooperate and take appropriate action to mitigate the severity or extent of any foreseeable system disturbance. Those operating criteria relating to emergency operation are set forth in this section.

A. Emergency Operating Philosophy

During an emergency condition, the security and reliability of the interconnected power system are threatened; therefore, immediate steps must be taken to provide relief. The following operating philosophy shall be observed:

1. **Corrective action.** The entity(ies) experiencing the emergency condition shall take immediate steps to relieve the condition by adjusting generation, changing schedules between control areas, and initiating relief measures including manual or automatic load shedding (if required) to relieve overloading or imminent voltage collapse. ACE shall be returned to zero or to its predisturbance value within the time specified in the Disturbance Control Standard following the start of a disturbance.

2. **Written authority.** Dispatching personnel shall have full responsibility and written authority to implement the emergency procedures listed in 5.A.1. above.

3. **Reestablishing reserves.** Operating entities or control areas shall immediately take steps to reestablish reserves to protect themselves and ensure that loss of any subsequent element will not violate any operating limits. The time taken to restore resource operating reserves shall not exceed 60 minutes.

4. **Notifying other affected entities.** In the event of system emergencies involving loss of any element(s), all affected entities and control areas shall be notified of the extent of the outage and estimated time of restoration. Preliminary emergency outage notification shall be provided via the WECC Communication System as quickly as possible. Restoration information, if not available immediately, shall be provided as soon as practicable.

5. **AGC.** AGC shall remain in service as long as its action continues to be beneficial. If AGC is out of service, manual control shall be used to adjust generation. AGC shall be returned to service as soon as practicable.

6. **Prompt restoration.** The affected entity(ies) and control area(s) shall restore the interconnected power system to a secure and reliable state as soon as possible.

7. **Zeroing schedules.** Energy schedules on a transmission path shall be promptly reduced to zero following an outage of the path unless a backup transmission path has been pre-arranged. If a system disturbance results in system islanding, all energy schedules across open paths between islands shall be immediately reduced to zero unless doing so would prolong frequency recovery.

8. **Emergency total transfer capability limits.** Emergency total transfer capability limits shall be established which will permit maintaining stability with voltage levels, transmission line loading and equipment loading within their respective emergency limits in the event another contingency occurs.

9. **Adjustments following loss of resources.** Following the loss of a resource within a control area, scheduled and actual interchange shall be re-balanced within the time specified in the Disturbance Control Standard following the loss of a resource within a control area. Following the loss of a remote resource or curtailment of other interchange being scheduled into a control area with no backup provisions, the energy loss shall be immediately reflected in the control area's ACE and corrected within the time specified in the Disturbance Control Standard.

B. Coordination with Other Entities

1. **Emergency outages.** Information regarding emergency outages of facilities, the time frame for restoration of these facilities, and the actions taken to mitigate the effects of the outages must be exchanged promptly with other affected entities.

2. **Voltage collapse.** Information regarding problems that could lead to voltage collapse shall be disseminated to other affected entities. Operation to alleviate the effects of such severe conditions shall be coordinated with all affected entities.

3. **Other affecting conditions.** Information regarding violent weather disturbances or other disastrous conditions which could affect the security and reliability of the interconnected power system shall be disseminated to all affected entities. Operation to alleviate the effects of such severe conditions shall be coordinated with all affected entities.

4. **Single contingency exposure.** All affected entities shall be notified promptly via the WECC Communication System by any entity forced to operate in such a way that a single contingency outage could result in general system instability, uncontrolled separation, cascading outages, or voltage collapse. Entities not connected to the WECC Communication System shall make this notification through their host control area.

5. **Emergency support personnel.** All control areas shall arrange for technical and management support personnel to be available 24 hours per day to provide coordination support in the event of system disturbances or emergency conditions. These personnel shall be on call to coordinate collecting and sharing of information. Each control area shall develop procedures in coordination with the Reliability Coordinators and the WECC office to fulfill this support responsibility. The Reliability Coordinators shall expedite communication of appropriate information to the WECC office during system disturbances and emergency operating conditions to enable the WECC office to coordinate the reporting of information pertaining to the entire western region to federal agencies, regulatory bodies, and the news media in a timely manner. Management support personnel shall maintain close and timely communication with the WECC office during extreme emergency conditions or system disturbances of widespread significance in the Western Interconnection.

C. Insufficient Generating Capacity

1. **Capacity or energy shortages**

   (a) A control area experiencing capacity or energy shortages after exhausting all possible assistance from entities within the control area shall immediately request assistance from adjacent control areas or entities. Neighboring control areas shall be notified as to the amount of the capacity or energy shortages. Neighboring control areas shall make every effort to provide all available assistance.

   (b) If inadequate relief is obtained from (a) above, then,

      (1) Procedures outlined in the *WECC Procedure for Securing Emergency Assistance* shall be implemented.

      (2) Control area(s) shall initiate relief measures as required to maintain reserves.

2. **Deficient control area.** A control area is considered deficient when:

   - all available generating capacity is loaded, and
   - all operating reserve is utilized, and
   - all interruptible load and interruptible exports have been interrupted, and
   - all emergency assistance from other control areas is fully utilized, and
   - the ACE is negative and cannot be returned to zero in the time specified in the Disturbance Control Standard.

   In this case, it will be necessary to manually shed firm load without delay to return the ACE to zero.

3. **Manual load shedding.** Through written standing orders and instructions the system dispatchers shall be given clear authority to implement manual load shedding without consultation whenever, in their judgment, such immediate action is necessary to protect the reliability and integrity of the system. Manual load shedding may also be required to restore system frequency which has stabilized below 60 Hz or to avoid an imminent separation which would produce a severe deficiency of power supply in the affected area. Upon system separation or islanding, manual load shedding may be required to restore system frequency which has stabilized below 60 Hz.

D. Restoration

Following a major disturbance which may require load shedding, sectionalizing, or generator tripping, immediate steps must be taken to return the system to normal. Extreme care must be exercised to avoid prolonging or compounding the emergency. While each disturbance will be different and may require different dispatcher action, the criteria set forth in the following subsections will provide the general guidelines to be observed. It is imperative that dispatchers maintain close coordination with neighboring dispatchers during restoration as follows:

1. **Extent of island.** Determine the extent of the islanded area or areas. Take any necessary action to restore area frequency to normal, including adjusting generation, shedding load and synchronizing available generation with the area.

   The following is a checklist of items to be communicated to determine any action required prior to reconnecting systems following a major disturbance:

   (a) Determine the condition of your own system:

   (1) Separation points

   (2) Overloaded ties

   (3) Power flows

   (4) Condition of generation

   (5) Load shed

   (b) Contact immediate neighbors to determine their condition:

   (1) Effect of the disturbance on them.

   (2) Their separation points.

   (3) Can a tie be made to them which will help your system or will help their system?

   (4) The amount of their or your system to be paralleled or picked up.

   (5) The relative speeds of the two systems and the potential impacts of closing the tie.

   (6) Overload conditions or potential overloads to be made worse or better by the tie.

   (7) The voltage difference between the two systems that must be corrected by shedding load, adjusting generation or connecting reactive equipment before the tie is closed.

   (c) Determine the best tie to be made among neighbors. Proceed to make the tie as recommended in the *WECC Interconnection Disturbance Assessment and Restoration Guidelines* in the OC Handbook.

2. **Start-up power.** Prior to restoring large customer loads, provide start-up power to generating stations and off-site power to nuclear stations where required. Adjacent entities shall establish mutual assistance arrangements for start-up power to expedite prompt restoration.

3. **Synchronizing areas.** As soon as voltage, frequency and phase angle permit, synchronize the islanded area with adjacent areas, using extreme caution to avoid unintentionally synchronizing large interconnected areas through relatively weak lines.

4. **Restoring loads.** Loads which have been shed during a disturbance shall only be restored when system conditions have recovered to the extent that those loads can be restored without adverse effect. If loads are reconnected by manual means or by supervisory control, they shall be restored only by direct action or order of the dispatcher, as generating capacity becomes available and transmission ties are reconnected. Loads shall not be manually restored until sufficient generating resources are available to return the ACE to zero within ten minutes. If automatic load restoration is used, it shall comply with the *WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan* and any other more stringent local program established in thorough coordination with neighboring systems and designed to avoid the possibility of recreating underfrequency, overloading ties, burdening neighboring systems, or delaying the restoration of ties. Relays installed to restore load automatically shall be set with varying and relatively long time delays, except in those cases where automatic load restoration is designed to protect against frequency overshoot.

E. Disturbance Reporting

Information and experience gained from studying disturbances which affect the operation of the interconnected power system are helpful in developing improved operating techniques.

1. **Disturbance analysis.** Entities and coordinated groups of entities within the WECC shall establish procedures and responsibility for collecting, analyzing and disseminating information and data concerning major disturbances. To facilitate post disturbance analyses, oscillographic and event recording equipment shall be installed at all key locations and synchronized to National Institute of Standards and Technology time.

2. **Recommendations.** Recommendations for eliminating or alleviating causes and effects of disturbances shall be made when appropriate.

F. Sabotage Reporting

Each operating entity or control area shall establish procedures for recognizing and reporting unusual occurrences suspected or determined to be acts of sabotage. These procedures shall cover recognizing acts of sabotage, disseminating information regarding such acts to the appropriate persons or entities within the area or within the interconnected power system, and notifying the appropriate local or regional law enforcement agencies.

Section 6 - Operations Planning

Each operating entity and coordinated group of operating entities is responsible for maintaining, and implementing as required, a set of current plans which are designed to evaluate options and set procedures for secure and reliable operation through a reasonable future time period. This section specifies requirements for operations planning to maintain the security and reliability of the interconnected power system.

A. Normal Operations

1. **Operating studies.** Studies conducted to obtain information which identifies operating limitations affecting transmission capability, generating capability, other equipment capability and power transfers between transmission providers or control areas shall be coordinated. To be considered acceptable, operating study results must be in compliance with the WECC Disturbance-Performance Table within the *NERC/WECC Planning Standards*.

2. **Transfer limits under outage and abnormal system conditions.** In addition to establishing total transfer capability limits under normal system conditions, transmission providers and control areas shall establish total transfer capability limits for facility outages and any other conditions such as unusual loads and resource patterns or power flows that affect the transfer capability limits.

3. **Joint agreement on limits.** All total transfer capability limits will be jointly agreed to by neighboring transmission providers or control areas.

B. Emergency Operations

1. **Emergency plans.** A set of plans shall be developed, maintained, and implemented as required by each operating entity or coordinated group of operating entities to cope with operating emergencies. These plans shall be coordinated with the Reliability Coordinators and other entities or coordinated groups of entities as appropriate. The plans shall be reviewed at least annually to ensure that they are up to date and a copy of the plans shall be provided to the Reliability Coordinators and shared with other entities as appropriate.

2. **Loads requiring backup power.** A reliable, adequate and automatic backup power supply shall be provided for the control center and other critical locations to ensure continuous operation of control equipment, communication channels, metering and recording equipment and other critical equipment during loss of normal power supply. Such backup power supply shall be adequate to carry equipment through a prolonged power interruption.

C. Automatic Load Shedding and System Sectionalizing

All control areas, coordinated groups of entities, and other entities serving load, shall jointly determine potential system separation points and resulting system islands and establish a program of automatic high-speed load shedding designed to arrest frequency decay. Such a program is essential in minimizing the risk of total system collapse in the event of separation, protecting generating equipment and transmission facilities against damage, providing for equitable load shedding among entities serving load and improving overall system reliability. Such islanding and load shedding should be controlled so as to leave the islands in such condition as to permit rapid load restoration and reestablishment of interconnections.

1. **WECC regional coordination.** As new transmission facilities are constructed and study results and/or actual operating experience indicate differing islanding patterns, individual area load shedding programs shall be altered or integrated into other area programs to maintain an overall coordination of load shedding programs within the WECC.

A coordinated load shedding program shall be implemented to shed the necessary amount of load in each island area to arrest frequency decay, minimize loss of load and permit timely system restoration. Such island areas shall devise load shedding plans in accordance with the criteria outlined in the subsections that follow. As part of its participation in a coordinated load shedding program with neighboring entities, each entity serving load shall be equipped to automatically shed load at separate frequency levels over an appropriate frequency range. The load shedding shall be matched to the island area needs and coordinated within the island area.

2. **Underfrequency relays.** All automatic underfrequency load shedding comprising a coordinated load shedding program shall be accomplished by use of solid-state underfrequency relays. Electro-mechanical relays shall not be used as part of any coordinated load shedding program. In each island area, all relay settings shall be coordinated and based on the characteristics of that island area. It is essential that the underfrequency load shedding relay settings are coordinated with underfrequency protection of generating units and any other manual or automatic actions which can be expected to occur under conditions of frequency decline.

3. **Technical studies.** The coordinated automatic load shedding program shall be based on studies of system dynamic performance, under conditions which would cause the greatest potential imbalance between load and generation, and shall use the latest state-of-the-art computer analytical techniques. The studies shall be able to predict voltage and power transients at a widespread number of locations, as well as the rate of frequency decline, and shall reflect the operation of underfrequency sensing devices.

4. **Load shedding steps.** Automatic high-speed load shedding shall comply with the *WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan* so as to minimize the risk of further separation, loss of generation, excessive load shedding accompanied by excessive overfrequency conditions, and system shutdown.

5. **Generators isolated to local load.** Where practical, generators shall be isolated with local load to minimize loss of generation and enable timely system restoration in situations where the load shedding program has failed to arrest frequency decline.

6. **Separation.** The opening of intra-area and inter-area transmission interconnections by underfrequency relaying shall only be initiated after the coordinated load shedding program has failed to arrest frequency decline and intolerable system conditions exist.

7. **Voltage reduction.** If voltage reduction is utilized for manual load relief, such reduction shall not be made to the high voltage transmission system.

8. **Protection from high frequency.** In cases where area isolation with a large surplus of generation in relation to load requirements can be anticipated, automatic generator tripping or other remedial measures shall be used to

prevent excessive high frequency and resultant uncontrolled generator tripping and/or equipment damage.

D. System Restoration

1. **Restoration plan.** Each transmission provider and control area shall have an up-to-date restoration plan and provide personnel training and telecommunication facilities needed to implement the restoration plan following a system emergency. Entities and coordinated groups of entities shall coordinate their restoration plans with other affected entities or coordinated groups of entities. All restoration plans shall be reviewed a minimum of every three years.

2. **Synchronizing.** To the extent possible, synchronizing locations shall be determined ahead of time and dispatchers shall be provided appropriate procedures for synchronizing. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect resynchronization.

E. Control Center Backup

Each control area shall have a plan to provide continued operation in the event its control center becomes inoperable. For interconnected operations, the goal of this plan is to avoid placing a prolonged burden on neighboring control areas during a control center outage. Since most control centers differ in their internal functions and responsibilities, each control area should decide which specific functions, other than the basic functions shown below, will be necessary to continue their operations from an alternate location. These criteria do not obligate control areas to provide complete and redundant backup control facilities, but to provide essential backup capability. Each control area may, as an option, make appropriate arrangements with another control area to provide the minimum backup control functions in the event its primary control functions are interrupted. As part of its plan the control area is expected to comply with the following requirements (through automatic or manual means) as a minimum:

1. **Notification.** Provide prompt notification, which should include any necessary pertinent information, to other control areas in the event that primary control center functions are interrupted.

2. **Communications.** Maintain basic voice communication capabilities with other control areas.

3. **Schedules.** Maintain the status of all interarea schedules such that there is an hourly accounting of all schedules.

4. **Critical interconnections.** Know the status of and be able to control all critical interconnection facilities.

5. **Tie line control.** Provide basic tie line control capability to avoid burdening neighboring control areas with excessive inadvertent interchange.

6. **Periodic tests.** Conduct periodic tests of backup and control functions to ensure they are in working order.

7. **Procedures and training.** Provide adequate written procedures and training to ensure that operating personnel are able to implement all backup control functions when required.

Section 7 - Telecommunications

For a high degree of service reliability under normal and emergency operation, it is essential that all entities have adequate and reliable telecommunication facilities.

A. Facilities

1. **Between control centers.** At least one main telecommunication channel with an alternate backup channel shall be provided between control centers of adjacent interconnected control areas, between control centers and key stations within a control area, and between other control areas as required.
2. **Alternate facilities.** Alternate facilities shall be provided to protect against interruption of essential telemetering, control and relaying telecommunications.
3. **Standby power supply.** Telecommunication facilities shall be provided with an automatic standby emergency power supply adequate to supply requirements for a prolonged interruption.

B. WECC Communication System

Control area control centers shall be connected to the WECC Communication System either directly or via pool communication facilities and the terminals shall be readily available to the dispatchers. Other transmission providers are encouraged to be connected to the WECC Communication System.

C. Loss of Telecommunications

Each control area shall have written operating instructions and procedures to enable continued operation of the system during loss of telecommunication facilities.

Section 8 - Operating Personnel and Training

To maintain a high degree of interconnected power system reliability, it is necessary that the interconnected power system be operated by qualified and knowledgeable personnel.

A. Responsibility and Authority

1. **Written authority.** Each system operator shall be delegated sufficient authority in writing to take any action necessary to ensure that the system or control area for which the operator is responsible is operated in a stable and reliable manner.

B. Requirements

1. **Dispatchers/System Operators and plant operators.** Dispatchers/System Operators and plant operators shall be qualified, trained and thoroughly indoctrinated in the principles and procedures of interconnected power system operation.

2. **Other personnel.** Other personnel involved in system operations, including, but not limited to, schedulers, contract writers, marketers, and energy accountants, shall be thoroughly familiar with the procedures and principles of interconnected power system operation which pertain to their job function.

C. Training

1. **Regular training.** Training shall be conducted regularly to keep all operating personnel involved in the operation of the interconnected power system abreast of changing conditions and equipment on their own system and on other interconnected systems. WECC Members and other entities are encouraged to use the WECC Training Program as a supplement to their internal training programs.

2. **Contingency analysis.** System operating personnel shall be kept informed through appropriate power flow and stability studies of the effect that failure or loss of various system components has upon the reliability of their control area and the interconnected systems.

D. Certification.

Statement of intent: Certification is intended to apply to those Dispatchers/System Operators in a position to make and/or carry out decisions, without review by higher authority, that impact interconnected system reliability. "Higher authority" means entities such as Control Areas, ISOs, and Reliability Coordinators.

Personnel who must be certified:

- Reliability Coordinators;
- Dispatchers/System Operators who:
  - are employed by a WECC Operating Authority, and
  - have the primary responsibility, either directly or through communication with others, for the real-time operation of the Western Interconnection , and
  - are directly responsible for complying with WECC Minimum Operating Reliability Criteria,

shall be WECC-Certified. Dispatchers/System Operators on shift, including shift supervisors, and management personnel who direct the real-time actions of Dispatchers/System Operators shall be WECC-Certified (i.e., only WECC-Certified personnel may direct the real-time operation of the power system). In addition, WECC Trainers shall be both NERC- and WECC-Certified. Certification is not intended to apply to substation or power plant operators.

Exception. *Any organization required to have WECC-Certified Dispatchers/System Operators shall have a period not to exceed three years from the time it employs a new Dispatcher/System Operator or a new trainee in the Dispatcher/System Operator position to ensure the new employee attains WECC Certification. For at least the first of those three years, the uncertified Dispatcher/System Operator shall work only in a non-independent position with a WECC-Certified Dispatcher/System Operator.*

Operating Authority Definition. Control Areas and Independent System Operators are considered Operating Authorities.

Period of Certification. The WECC Dispatcher/System Operator Certification credential shall be valid for a period of five years from the date of passing the certification examination.

a) **Recertification.** To maintain a continuous WECC Certification credential, WECC-Certified Dispatcher/System Operators shall be recertified before their current certification expires.

b) **Lapsed Certification.** If a Dispatcher/System Operator's WECC Certification credential expires, or if the Dispatcher/System Operator fails the recertification examination, the Dispatcher/System Operator shall not be considered a WECC-Certified Dispatcher/System Operator.

Certification Examination. The certification examination shall measure the Dispatcher/System Operator's knowledge of the WECC Minimum Operating Reliability Criteria, WECC Policies and Procedures and the basic principles of operating the Western Interconnection.

Administration. The WECC Dispatcher/System Operator Certification examination will be administered on a pre-scheduled periodic basis at sites in the western United States and Canada.

E. Information Sharing

1. **Information requirements.** Each operating entity's personnel shall respond to the information requirements of other operating entities, coordinated groups of operating entities, and the WECC Operating Committee.

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WESTERN ELECTRICITY COORDINATING COUNCIL

DEFINITIONS

PART IV

WESTERN ELECTRICITY COORDINATING COUNCIL

NERC/WECC PLANNING STANDARDS
AND
MINIMUM OPERATING RELIABILITY CRITERIA

DEFINITIONS

Adequacy

The ability of a bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

Adjustment

Manual or automatic action following a disturbance. These actions are taken to prevent unacceptable system performance should a subsequent disturbance occur prior to system restoration.

Angular Stability

Angular positions of rotors of synchronous machines relative to each other remain constant (synchronized) when no disturbance is present or become constant (synchronized) following a disturbance. If the interconnected transmission system changes too much or too suddenly, some synchronous machines may lose synchronism resulting in a condition of angular instability.

Anti-Aliasing Filter

An analog filter installed at a metering point to remove aliasing errors from the data acquisition process. The filter is designed to remove the high frequency components of the signal over the AGC sample period.

Area Control Error (ACE)

The instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias (and time error or unilateral inadvertent interchange if automatic correction for either is part of the system's AGC).

Automatic Generation Control (AGC)

Equipment which automatically adjusts a control area's generation from a central location to maintain its interchange schedule plus frequency bias.

Automatic Voltage Control Equipment

Equipment which controls the output of reactive power resources based on local system voltage or loads.

Black-Start Capability

The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

Blackout

The disconnection of all electrical sources from all electrical loads in a specific geographical area. The cause of disconnection can be either a forced or a planned outage.

Bulk Power Transformers

Transformers which are connected in parallel with other elements of the bulk transmission network and therefore influence the loading and reliability of those other elements. A transformer which connects a radial load is not generally considered a bulk power transformer. Large generation step-up transformers are sometimes considered to be bulk power transformers.

Cascading

Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Contingency

Single Contingency - The loss of a single system element under any operating condition or anticipated mode of operation.

Most Severe Single Contingency - That single contingency which results in the most adverse system performance under any operating condition or anticipated mode of operation.

Multiple Contingency Outages - The loss of two or more system elements caused by unrelated events or by a single low probability event occurring within a time interval too short (less than ten minutes) to permit system adjustment in response to any of the losses.

Control Area

An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the interconnection.

Controlled Action

The switching of system elements as the planned response to system events or system conditions. For example, underfrequency and undervoltage load tripping are considered inherently controlled actions because the actions are the planned response to specific conditions on the system at the load locations. Out-of-step tripping of a line is considered an inherently controlled action because the action is the planned response to a specific condition on the line.

Random line tripping caused by protective relay action in response to a non-fault condition such as a system swing is generally considered an uncontrolled action because this action is not the normal response intended for the protective relay.

Controlled Islanding

The controlled tripping of transmission system elements in response to system disturbance conditions to form electrically isolated islands which are relatively balanced in their composition of load and generation. This controlled action is taken to prevent cascading, minimize loss of load, and enable timely restoration.

Credible

That which merits consideration in operating and planning the interconnected bulk electric system to meet reliability criteria.

Critical Generating Unit

A unit that is required for the purpose of system restoration.

Delayed Clearing

Delayed clearing occurs when the primary protection fails to clear the fault and backup relaying is required.

Disturbance

An unplanned event which produces an abnormal system condition such as high or low frequency, abnormal voltage, or oscillations in the system.

Embedded System

The integrated electrical generation and transmission facilities owned or controlled by one organization that are integrated in their entirety within the facilities owned or controlled by another single system.

Emergency

Any abnormal system condition which requires immediate manual or automatic action to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of the electric system.

Emergency Limit

The loading of a system element in amperes or MVA or the voltage level permitted by the owner of the element for a maximum duration of time such as thirty minutes or other similar short period.

Entity

A participant who is involved in the transmission, distribution, generation, scheduling, or marketing of electrical energy. Participants include, but are not limited to utilities, transmission providers, independent power producers, brokers, marketers, independent system operators, local distribution companies, and control area operators.

Frequency Bias

A value, usually given as MW/0.1 Hz, associated with a control area which relates the difference between scheduled and actual frequency to the amount of generation required to correct the difference.

Governor Droop

Governor droop is the decrease in frequency to which a governor responds by causing a generator to go from no load to full load. This definition of governor response is more precisely defined as "speed regulation" which is expressed as a percent of normal system frequency. For instance, if frequency decays from 60 to 57 hertz, a 5% change, a hydro generator at zero load with a governor set at a 5% droop would respond by going to full load. For smaller changes in frequency, changes in generator output are proportional. The more technically correct definition of governor droop is the change in frequency to which a governor responds by causing turbine gate position to move through its full range of travel, which is generally non-linear and a function of load.

Inadvertent Interchange

The difference between the control area's net actual interchange and net scheduled interchange.

Independent Power Producer

A producer of electrical capacity and energy which owns the generation asset, but does not typically own any transmission or distribution assets. Also known as a Non-Utility Generator (NUG).

Interconnected Power System

A network of subsystems of generators, transmission lines, transformers, switching stations, and substations.

Interruptible Imports, Exports and Loads

Those imports, exports and loads which by contract can be interrupted at the discretion of the supplying system.

Island

A portion of the interconnected system which has become isolated due to the tripping of transmission system elements.

Load Responsibility

A control area's firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the supplier.

Local Network

A Local Network (LN) is a non-radial portion of a system and has been planned such that a disturbance may result in loss of all load and generation in the LN.

1. The LN is not a control area.
2. The loss of the LN should not cause a Reliability Criteria violation external to the LN.

Natural Frequency Response Characteristic

Also called the "Natural Combined Characteristic" is the manner in which a system's generation and load would respond to a change in system frequency in the absence of AGC. In practice, system regulation is achieved by the combined effects of generation governing and load governing.

Planning Margin

The transmission capability remaining in the system to accommodate unanticipated events. It can be embedded in conservative modeling and system representation assumptions (built-in margin), and can be explicitly established as well with operating limits and facility ratings. Some of the more important margins are related to current overloads, transient stability performance, oscillatory damping, post-transient voltage, and reactive support. If systems are modeled accurately, simulation results will provide an accurate relationship to the selected margin criteria. Simulations using built-in margins (conservative simplifications) produce an inaccurate sense of what the actual margins are.

Radial System

A radial system is connected to the interconnected transmission system by one transmission path to a single location. For the purpose of application of this Reliability Criteria,

1. A control area is not a radial system.
2. The loss of the radial system shall not cause a Reliability Criteria violation external to the radial system.

Reactive Reserves

The capability of power system components to supply or absorb additional reactive power in response to system contingencies or other changes in system conditions. Reactive reserves may include additional reactive capability of generating units, and other synchronous machines, switchable shunt reactive devices, automatic fast acting devices such as SVCs, and other power system components with reactive power capability.

Regulating Margin

The amount of spinning reserve required under non-emergency conditions by each control area to bring the area control error to zero at least once every ten minutes and to hold the average difference over each ten-minute period to less than that control area's allowable limit for average deviation as defined by the NERC control performance criteria.

Reliability

The combination of Security and Adequacy, as defined in this section.

Remedial Action

Special preplanned corrective measures which are initiated following a disturbance to provide for acceptable system performance. Typical automatic remedial actions include generator tripping or equivalent reduction of energy input to the system, controlled tripping of interruptible load, DC line ramping, insertion of braking resistors, insertion of series capacitors and controlled opening of interconnections and/or other lines including system islanding. Typical manual remedial actions include manual tripping of load, tripping of generation, etc.

Remedial Action Scheme

A protection system which automatically initiates one or more remedial actions. Also called Special Protection System.

Reserve

Operating Reserve - That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning reserve and nonspinning reserve.

Spinning Reserve - Unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve.

Regulating Reserve - An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

Contingency Reserve - An additional amount of operating reserve sufficient to reduce Area Control Error to zero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this operating reserve shall be Spinning Reserve, which will automatically respond to frequency deviation.

Nonspinning Reserve - That operating reserve not connected to the system but capable of serving demand within ten minutes, or interruptible load that can be removed from the system within ten minutes.

Security

The ability of the bulk electric system to withstand sudden disturbances such as electric short circuits, unanticipated loss of system components or switching operations.

Simultaneous Outage

Multiple outages are considered to be simultaneous if the outages subsequent to the first event occur before manual system adjustment can be made. For simulation purposes, it may be assumed that the outages occur at the same instant, or the outages may be staggered if the time sequence is known.

System

The integrated electrical facilities, which may include generation, transmission and distribution facilities, that are controlled by one organization.

System Adjusted

System Adjusted means the completion of manual or automatic actions, acknowledging the outage condition, to improve system reliability and prepare for the next disturbance; i.e., change in generation schedules, tie line schedules, or voltage schedules. System Adjusted does not include automatic control action to maintain prefault conditions such as governor action, economic dispatch and tie line control, excitation system action, etc.

Total Transfer Capability (TTC)

The amount of electric power that can be transferred over the interconnected transmission network in a *reliable* manner while meeting *all* of a specific set of defined pre- and post-contingency system conditions.

Uncontrolled

The unanticipated switching of system elements at locations and in a sequence which have not been planned.

Unscheduled Flow

The difference between the scheduled and actual power flow, on a transmission path.

Voltage Collapse

A power system at a given operating state and subject to a given disturbance undergoes voltage collapse if post-disturbance equilibrium voltages are below acceptable limits. Voltage collapse may be total (blackout) or partial and is associated with voltage instability and/or angular instability.

Voltage Instability

A system state in which an increase in load, disturbance, or system change causes voltage to decay quickly or drift downward, and automatic and manual system controls are unable to halt the decay. Voltage decay may take anywhere from a few seconds to tens of minutes. Unabated voltage decay can result in angular instability or voltage collapse.

Western Interconnection

The interconnected electrical systems that encompass the region of the Western Electricity Coordinating Council of the North American Electric Reliability Council. The region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California (Mexico), and all or portions of the 14 western states in between.

November 3, 1981
Revised August 11, 1987
Revised November 15, 1988
Revised March 9, 1993
Revised December 2, 1994
Revised March 11, 1997
Revised March 8, 1999
Revised April 18, 2002
Revised August 9, 2002

WESTERN ELECTRICITY COORDINATING COUNCIL

PROCESS FOR DEVELOPING AND APPROVING WECC STANDARDS

PART V

PROCESS FOR DEVELOPING AND APPROVING WECC STANDARDS

Approved by WSCC Board of Trustees – August 24, 1999

Introduction

This is a previous Process of Western Systems Coordinating Council (WSCC) that has been adopted for use by WECC pursuant to the WECC Bylaws, Section 2.4, Transition.

This document explains the process that WECC has established for announcing, developing, revising, and approving WECC Standards. WECC Standards include WECC Operating, Planning, and Market Interface Policies, Procedures, and Criteria, and their associated measurements for determining compliance. The process involves several steps:

- Public notification of intent to develop a new Standard, or revise an existing Standard.
- Subcommittee drafting stage.
- Posting of draft for public comment.
- Subcommittee review of all comments and public posting of decisions reached on each comment.
- WECC Market Interface Committee, Operating Committee, or Planning Coordination Committee approval of proposed Standard.
- Appeals Committee resolution of any "due process" or "technical" appeals.
- WECC Board of Directors (Board) approval of proposed Standard.

The process for developing and approving WECC Standards is generally based on the Standard-making procedures used by the American National Standards Institute (ANSI), the Institute of Electrical and Electronics Engineers (IEEE), and the American Society of Mechanical Engineers (ASME):

1. Notification of pending Standard change before a wide audience of all "interested and affected parties,"
2. Posting Standard change drafts for all parties to review,
3. Provision for gathering and posting comments from all parties,
4. Provision for an appeals process – both "due process" and "technical" appeals.

The issues of compliance and enforcement of the WECC Standards are currently being addressed and implemented through the WECC Reliability Management System (RMS). In cases requiring expediency, such as in the development of emergency operating procedures, the Market Interface Committee, Operating Committee, or Planning Coordination Committee may approve a new or modified Standard. Any such Standard must have an associated termination date and, even though already implemented, must undergo the formal technical review and approval process. Should this Standard not be formally approved through WECC's Standards development and approval process it will cease to be in effect upon conclusion of the process.

Terms

Standards Committee. The Market Interface Committee (MIC), Operating Committee (OC) or Planning Coordination Committee (PCC)[1]. MIC, OC, and PCC will coordinate their responsibilities for those Standards that have a combination of market, operating, and planning implications.

Subgroup. A subcommittee, work group, or task force of the MIC, OC, PCC, or a combination of representatives from these committees; usually where WECC Standards are drafted and posted for review[2].

Due Process Appeals Committee. The committee that receives comments from those who believe that the "due process" procedure was not properly followed during the development of a Standard. The Due Process Appeals Committee consists of three Directors appointed by the Board Chair. The WECC Executive Director shall be the staff coordinator for the Due Process Appeals Committee. Decisions of the Appeals Committee will be based upon a majority vote.

Technical Appeals Committee. The committee that receives comments from those who believe that their "technical" comments were not properly addressed during the development of a Standard. The Technical Appeals Committee consists of the vice chairs of the Market Interface Committee, Operating Committee, Planning Coordination Committee, and a Director appointed by the Board Chair. The WECC Executive Director shall be the staff coordinator for the Technical Appeals Committee. The Technical Appeals Committee will make assignments as necessary to existing WECC technical work groups and task forces, form new technical groups if necessary, and utilize other technical resources as required to address technical appeals. Decisions of the Technical Appeals Committee will be based upon a majority vote.

Steps

Step 1 – Request To Revise or Develop a Standard

Requests to revise or develop a Standard are submitted to the Board of Directors (Board), or to the Standards Committee (WECC MIC, OC, or PCC). Requests submitted to the Board will be assigned to MIC, PCC, or OC, as appropriate, on a case by case basis. Requests submitted to MIC, PCC, or OC directly will be evaluated by these respective committees to determine which committee should address the requests. In some

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1 Membership in WECC's Market Interface Committee, Planning Coordination Committee, and Operating Committee is in accordance with WECC's Bylaws.

2 Formation of Subgroups is in accordance with the Market Interface Committee's, Planning Coordination Committee's, and Operating Committee's *Organizational Guidelines*.

instances a joint involvement will be needed to address requests that are applicable to planning, operating, and market issues. Changes to the WECC Standards may be offered by any individual or organization with a legitimate interest in electric system reliability, such as:

- Transmission owners
- Generation owners
- Independent System Operators (ISOs)
- Transmission dependent utilities
- Independent power producers
- Power marketers
- Customers, either retail or wholesale for resale
- State agencies concerned with electric system reliability
- WECC subgroups
- Electric industry organizations

A request to revise or develop a Standard must include an explanation of the need for a new or revised Standard and be accompanied by a preliminary technical assessment performed by, or prepared under the direction of, the entity(ies) supporting the request.

Step 2 – Assignment to Subgroup

The Board or Standards Committee then assigns the request to whichever Subgroup(s) is responsible for those issues. If a proposed new Standard or revision to an existing Standard has implications for any combination of planning, operations, or market issues, the Subgroup will include a composite of individuals having the appropriate planning, operations, and market expertise. Notification of such assignments will be posted on the WECC web site and sent to all parties that subscribe to the WECC Standards e-mail list. Interested parties may express their interest in participating in the deliberations of the Subgroup. The Subgroup membership will be administered in accordance with the WECC Bylaws.

Step 3 – Subgroup Begins Drafting Phase and Announces on WECC Web Site

The Subgroup will begin working on the new or revised request no later than at its next scheduled or special meeting. A minimum of 30 days notice will be provided prior to all Subgroup meetings in which new or revised Standards will be developed. Notification of such meetings will be posted on the WECC web site and sent to all parties that subscribe to the WECC Standards e-mail list. These meetings will be open to stakeholders having a legitimate interest in electric system reliability. The Subgroup Chair will allow some opportunity for outside comment and participation as the discussion progresses. However, the Subgroup Chair will not allow the discussion to interfere with productive discussions by the Subgroup members.

The Subgroup will review the preliminary technical assessment provided by the requester and may perform or request additional technical studies if considered necessary. The

Subgroup will complete an impact assessment report as part of its evaluation to assess the potential effects of the requested Standards change. The Subgroup may request from the Board or Standards Committee additional time to study the proposed new or revised Standard if the Subgroup believes it necessary to fully assess the proposed change. If the Subgroup determines that a new Standard or change in an existing Standard is needed, it announces the pending change, provides a summary of the changes it expects to draft, and provides an explanation as to why the new Standard or change in an existing Standard is needed. The announcement and the impact assessment report will be posted on the WECC web site and sent to all parties that subscribe to the WECC Standards e-mail list. If the Subgroup determines that a new or revised Standard is not needed, it prepares and posts the response to the party that submitted the proposal with a copy to the MIC, PCC, OC, or Board, as appropriate.

Step 4 – Draft Standard Posted for Comment

The Subgroup will post its first draft of the new or revised Standard on the WECC web site and provide 60 days for comments. The draft must include specific measurements for determining compliance and the estimated costs of compliance. Comments on the draft will be solicited from the WECC members and all individuals who subscribe to the WECC Standards e-mail list. Members of electric industry organizations may respond through their organizations, or directly, or both. All comments should be supplied electronically. WECC will then post all comments it receives on the WECC web site.

Step 5 – Subgroup Deliberates on Comments

Based on the comments it receives, plus its own review, the Subgroup will revise the draft Standard as needed. It will document its disposition on all comments received, and post its decisions on the WECC web site along with its second draft for either further industry review or Standards Committee vote. If the Subgroup believes the technical comments are significant, it will repeat Steps 3 and 4, before sending a revised draft to the Standards Committee. Steps 3 and 4 will be repeated as many times as considered necessary by the subgroup to ensure an adequate review from a "technical" perspective. The number of days for comment on each new draft of a proposed new or revised Standard will be 60 days, similar to the review period on the initial draft of the Standard. Parties who have their technical comments on a proposed Standard rejected by a Subgroup may write to the Standards Committee for further consideration of their comments.

A majority vote of the Subgroup is required to approve submitting the recommended Standard to the Standards Committee for a vote. The vote may be by mail, conference call and/or e-mail ballot.

Step 6 – Subgroup Submits Draft for Standards Committee Vote

The Subgroup's final draft Standard is posted on the WECC web site and sent to the Standards Committee for a vote. The posting will include all comments that were not incorporated into the draft Standard and the date of the expected Standards Committee's vote. The posting will also be sent to the Standards e-mail list with attachments. Proposed Standards will be posted no less than 30[3] days prior to the Standards Committee vote.

Standards may be voted on in their entirety or by individual provisions. The Subgroup will determine how each Standard will be addressed for vote. The Subgroup will also recommend the subdivisions to be addressed and voted on as individual provisions. To be considered by the Standards Committee, any "no" votes, by Subgroup members, on a proposed Standard should be accompanied by a text explaining the "no" vote and if possible specific language that would make the Standard acceptable.

Step 7 – Standards Committee Votes on Recommendation to Board

The Standards Committee will vote on the draft Standard no later than at its next scheduled or special meeting. A minimum of 30[4] days notice will be provided prior to all Standards Committee meetings in which new or revised Standards will be considered for approval. Notification of such meetings will be posted on the WECC web site and sent to all parties that subscribe to the WECC Standards e-mail list. Whenever it determines that a matter requires an urgent decision, the Board may shorten the time period set forth in this section, provided that: 1) notice and opportunity for comment on recommendations will be reasonable under the circumstances; and 2) notices to Members will always contain clear notification of the procedures and deadlines for comment. If the Standards Committee approves the Standard, it sends its recommendation, the draft Standard, and any comments on which the Standards Committee did not agree, plus Standards Committee minority opinions, to the Board for final approval. To be considered by the Board, any "no" votes, by members of the Standards Committee, on a proposed Standard should be accompanied by a text explaining the "no" vote and if possible specific language that would make the Standard acceptable. Proposed Standards will be posted no less than 30[5] days prior to the Board vote. The date of the expected Board vote shall also be posted. The Standards Committee may amend or modify a proposed Standard. The reasons for the modification(s) shall be documented, posted, and provided to the Board. If the Standards Committee's recommendation changes significantly as a result of comments received, the committee will post the revised recommendation on the WECC web site, provide e-mail notification to Members, and provide no less than ten (10) days for additional comment before reaching its final recommendation. Any parties that object to the modifications may appeal to the appropriate Appeals Committee. These items shall all be posted on the WECC web site for general review. If the Standards Committee does

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[3] WECC Bylaws, Section 8.6 – require "not less than ten (10) days notice of all standing committee meetings…"

[4] WECC Bylaws, Section 8.6 – require "not less than ten (10) days notice of all standing committee meetings…" Section 8.7 – "All committee meetings of the WECC will be open to any WECC Member and for observation by any member of the public."

[5] WECC Bylaws, Section 7.5.1 – "Except as set forth in Section 7.5.2 regarding urgent business, all regular business of the Board will occur at the Board meetings, at least twenty-one (21) days' advance notice of which has been provided…"

not approve the Standard, it may return the draft to the Subgroup for further work or it may terminate the Standard development activity with the posting of an appropriate notice to the Standards originator, the Subgroup, and the Board (if appropriate).

A majority vote of the Standards Committee, as specified in Section 8.5.4 of the WECC Bylaws, is required to approve submitting the recommended Standard to the Board for a vote. The vote may be by mail, and/or e-mail ballot.

Step 8 – Appeals Process

After approval and posting by the Standards Committee, any due process or technical appeals are due, in writing, to the respective Due Process Appeals Committee or Technical Appeals Committee within 15 days. If an Appeals Committee accepts the appellant's complaint, it rejects the draft Standard and refers the complaint to the Standards Committee or Board for further consideration. If an Appeals Committee denies the complaint, it approves the Standard for referral to the Board. Deliberations of the Appeals Committees shall not exceed 15 days.

Step 9 – Board Approval

The Board will vote on the proposed Standard no later than at its next scheduled or special meeting. It will consider the Standards Committee's recommendations and minority opinions, all comments that were not incorporated into the draft Standard, and inputs from the Due Process and Technical Appeals Committees. To preserve the integrity of the due process Standards development procedure, the Board may not amend or modify a proposed Standard. If approved, the Standard is posted on the WECC web site and all parties notified. If the Standard is not approved, the Board may return the Standard to the Standards Committee for further work or it may terminate the Standard activity with an appropriate notice to the Standard originator and Standards Committee. These Board actions will also be posted.

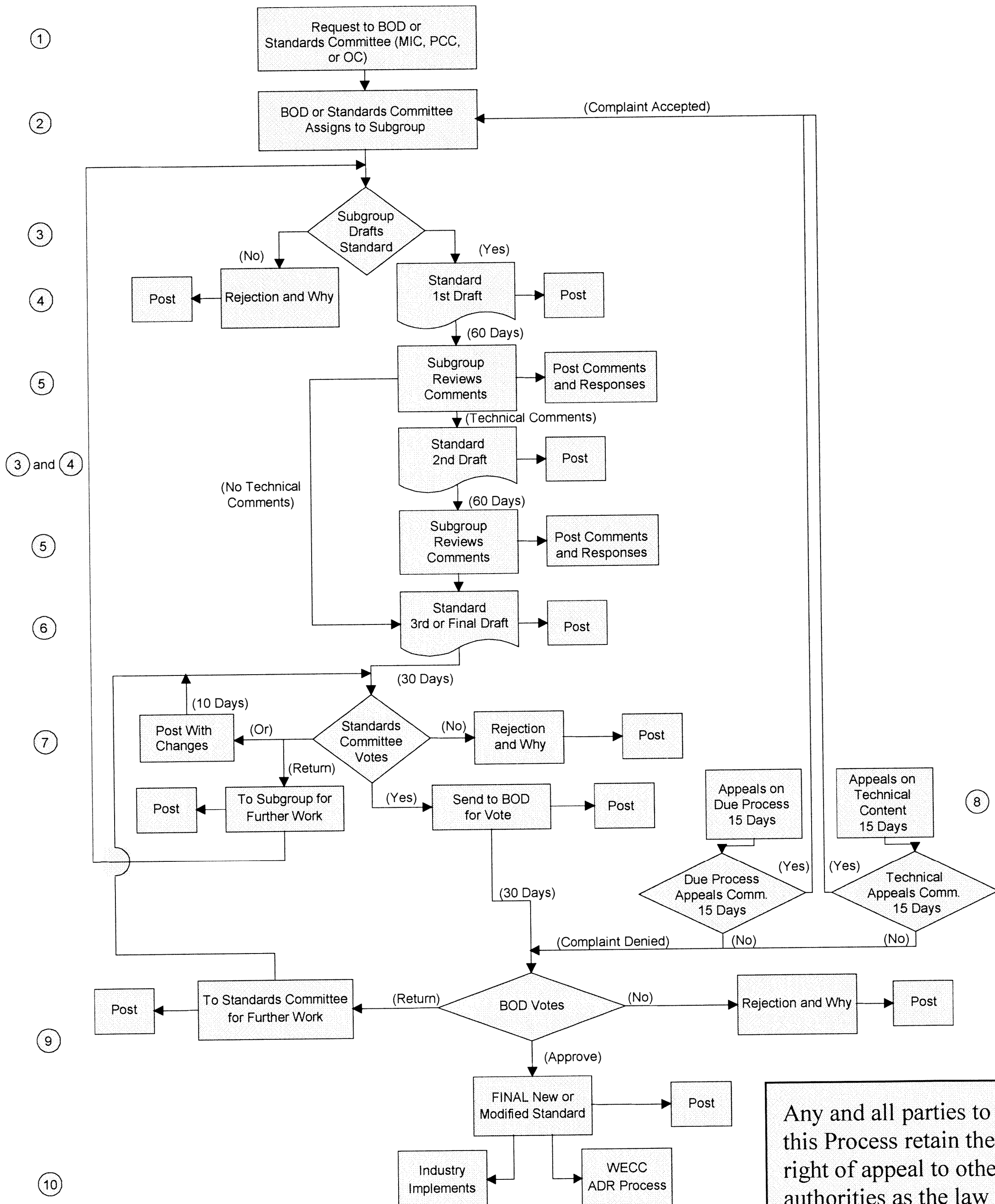
A majority vote of the Directors present at a Board meeting, as specified in Section 7.2 of the WECC Bylaws, is required to approve the recommended Standard.

Step 10 – Standard Implementation or Further Appeals

Once the Board approves a new or modified Standard, all industry participants are expected to implement and abide by the Standard in accordance with accepted WECC compliance procedures. Should a party continue to object to the new or modified Standard, that party may through a WECC member have access to WECC's alternative dispute resolution procedure to address its objections or seek other remedies as appropriate. Any and all parties to this Process retain the right of appeal to other authorities as the law allows.

Revised for Consistency with WECC Bylaws: June 21, 2002

Process for Developing and Approving WECC Standards



Any and all parties to this Process retain the right of appeal to other authorities as the law allows.

EXHIBIT 2

CALIFORNIA ISO

PLANNING STANDARDS

February 7, 2002

Table of Contents

I. Introduction

The purpose of this document is to specify the Planning Standards that will be used in the planning of ISO Grid transmission facilities. The primary principle guiding the development of the ISO Grid Planning Standards is to develop a consistent reliability standards for the ISO grid that will maintain or improve the level of transmission system reliability that existed with the pre-ISO planning standards.

The ISO Tariff specifies:

> "After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs, will work to develop a consistent set of reliability criteria for the ISO Controlled Grid which the TOs will use in their transmission planning and expansion studies or decisions."[1]

The ISO Tariff specifies in several places that the facilities that are to be added to the ISO Grid are to meet the Applicable Reliability Standard, which is defined as follows:

> "The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC."[2]

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 (PSC), which includes representation from all interested market participants. One of the primary roles of the PSC is to periodically review the ISO Grid Planning Standards and recommend changes as necessary. In recognition of the need to closely coordinate the development of the ISO Grid with neighboring electric systems both inside and outside of California, the approach taken by the PSC is to utilize regional (WSCC) and continental (NERC) standards to the maximum extent possible. These ISO Grid Planning Standards build off of, rather than duplicate, Standards that were developed by WSCC and NERC. The PSC has determined that the ISO Grid Planning Standards should:

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

The following Section details the ISO Grid Planning Standards. Also attached are interpretations of the terms used by NERC and background information behind the development of these standards.

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[1] ISO Tariff, October 13, 2000, Section 3.2.1.2, Original Sheet No. 144.
[2] ISO Tariff, October 13, 2000, Appendix A, Original Sheet No. 303.

II. ISO Grid Planning Standards

The ISO Grid Planning Standards include the following:

1. **NERC/WSCC Planning Standards -** The standards specified in the NERC/WSCC Planning Standards unless WSCC or NERC formally grants an exemption or deference to the ISO.

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.

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.

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 ISO Planning Standard 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 -** 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, WSCC (including voltage stability), and ISO standards (such as single line outage, 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 has not been designed to be used to determine Reliability Must-Run generation requirements. The RMR standards are intentionally developed separately from the Planning Standards.

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.

III. 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 primary action of a SPS 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. The alternatives to a SPS are 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 judgement 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.

<u>California ISO New Generator SPS Guides</u>

ISO G1. The overall reliability of the system should not be degraded after the combined addition of the SPS and the generator.

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 maximum 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. Generally, there should be no more than 4 local contingencies (single or credible double contingencies) that would trigger the operation of a SPS and the SPS should not be monitoring the loading on more than 4 system elements. The exception is that 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, then the new generation cannot materially increase the complexity of the existing SPS scheme. 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.

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 6 initiating events rather than limiting the SPS to 4 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.

IV. Interpretations of NERC/WSCC Planning Standard Terms

Listed below are several of the terms that are used in the NERC Planning Standards which members of the PSC have determined require clarification. Also provided below are ISO interpretations of these terms:

Bulk Electric System: The ISO Bulk Electric System refers to all of the facilities placed under ISO control.

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 PTOs and the ISO subject to appropriate coordination and review with the relevant state, local, and federal regulatory authorities and WSCC. The PTOs develop annual transmission plans, which the ISO reviews. Both the ISO and PTOs have the ability to identify transmission upgrades needed for reliability.

Entity Required to Develop load models: The TOs, in coordination with the UDCs and others, develop load models.

Projected Customer Demands: The load level modeled in the studies can significantly impact the facility additions that the studies identify as necessary. The PSC decided that 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 higher 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 in the ISO Grid Coordinated Planning Process 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.

V. 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[3] 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

[3] 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.

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.

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[4] 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[5] 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, And Peak MW	Communities	Frequency	Duration	Frequency	Duration

[4] 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.

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

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 projects or operating procedures[6]. 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.

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

VI. Background behind the San Francisco Greater Bay Area Generation Outage Standard

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 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.

TRANSMISSION CONTROL AGREEMENT

APPENDIX E

Nuclear Protocols

DIABLO CANYON NUCLEAR POWER PLANT
UNITS 1 & 2

REQUIREMENTS FOR OFFSITE
POWER SUPPLY OPERABILITY
REVISION 1

DCPP 1&2 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

OVERVIEW

During normal operation, each DCPP unit's electrical loads are supplied from the unit's main onsite electrical generator. If the generator is not available, either due to unit shutdown or other reason, the loads are transferred to an alternative source. The preferred immediate alternate source of electrical power for DCPP electric loads (safety-related and nonsafety-related) is the offsite power supply or 230kV grid In addition DCPP has a delayed 500 kV source. The offsite power source is sometimes referred to as the preferred power supply in the regulatory documents.

The basic requirement for the offsite power supply is that it provides sufficient capacity and capability for safe shutdown and design basis accident mitigation. When this condition is met, the offsite power supply is considered Operable with respect to the DCPP Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If the offsite power system is declared Inoperable, action must be taken to shut down an on-line DCPP units(s) and, for an off-line unit, to suspend activities as required by the DCPP Operating License and Technical Specifications. DCPP must also perform additional diesel testing. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power unavailable for safe shutdown and emergency purposes.

In specific terms, the offsite power supply voltage (at the DCPP switchyard) must stay within the range of 207 kV to 240kV under post accident operating conditions During normal operation the voltage must be held enough above 207kV so that when DCPP transfers it's load from the onsite source to the offsite source the voltage does not decrease below 207kV. For normal operation with all lines in service the voltage must be above 211kV. During normal operation, the voltage should be above 218kV. Otherwise the offsite power supply is considered Inoperable. Since a design basis accident can result in a unit trip, it is imperative that the trip not impair the operability of the offsite power system. Therefore, following a trip of a DCPP unit (i.e., the unit breakers open), the DCPP switchyard voltage must recover to and be maintained at or above 207 kV within 16 seconds following the trip. If this condition cannot be met, then the offsite power supply in the pre trip condition is considered Inoperable, and action must be taken to shut down the operating DCPP unit(s). In addition, the 500 and 230 kV grid must remain stable if both DCPP units trip.

System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and immediately communicated to the DCPP operating staff for Operability determination.

SPECIFIC REQUIREMENTS

Note: This section identifies the operational requirements for the DCPP offsite power supply. These requirements are part of the DCPP design basis and licensing basis and include PG&E System Operating Instruction 0-23 as revised from time to time. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating DCPP unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to PG&E and the DCPP operating staff for operability determination. Changes in the operation of the transmission network that conflict with these requirements require prior approval by PG&E.

1. Three transmission lines into the 500 kV switchyard and two lines into the 230 kV DCPP switchyard are normally in service. Any increase or decrease in the number of lines into the DCPP switchyard requires prior approval by PG&E.

   No line may be removed from service at anytime without prior notification to the DCPP Operations Department. At least two independent sources of power, the 500 kV and the 230kV system between the transmission network (grid) and DCPP switchyards shall be available at all times. PG&E System Operating Procedure, 0-23, Operating Instructions for Reliable Transmission Service for Diablo Canyon, provides specific requirements to determine operability of these sources.

2. With both Diablo Canyon units off-line, the DCPP 500 and 230kV offsite power source should be capable of providing 105MW and 78 MVAR to Diablo Canyon for normal operation, safe shutdown, and design basis accident mitigation.

3. The minimum grid voltage at DCPP switchyard shall be maintained at or above 218kV for normal operation with all lines in service. In the event of a system disturbance or line outage that can cause the voltage to dip below 218kV, including the trip of a DCPP unit, the grid voltage shall recover to 207kV or above within 16 seconds.

4. Planning and operating reliability criteria shall result in plans for the following events without loss of grid stability or availability:

   a) The loss of two DCPP units.

   b) The loss of any generating unit on the PG&E grid.

   c) The loss of any major transmission circuit or intertie on the PG&E grid.

   d) The loss of any large load or block of load on the PG&E grid.

5. The maximum grid voltage at the DCPP switchyard shall be maintained at or below 240kV. (References 10, 11)

6. The normal operating voltage of the DCPP switchyard shall be maintained at 230 kV. The DCPP switchyard voltage shall not exceed 240kV unless required to preserve transmission network integrity.

7. The 500 kV system shall be maintained between 510kV and 550kV. Operation of DCPP is limited between .97 p.u. and 1.05 p.u. Requests to operate above 1.01 p.u. shall be analyzed prior to implementation to assure viability of the 500kV and 230kV after a DCPP unit trip. If two of three 500 kV lines are out of service, spinning reserve must be available that is equal to the total of DCPP generation.

System studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions that could render offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable for safe shutdown and emergency purposes. Procedures and programs shall be in effect to ensure that the DCPP operating staff is immediately notified of such conditions. Grid conditions that are more severe with respect to DCPP switchyard voltages or otherwise unanalyzed, render the offsite power supply Inoperable. DCPP operating staff shall be immediately notified of such conditions. Auditable records of system study results shall be maintained. Study results, including revisions and updates, shall be transmitted via letter to PG&E. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be transmitted via letter to PG&E.

System studies shall consider the interconnections between PG&E, and other utilities in the Western States Coordinating Council (WSCC) region.

8. In the event of loss of the DCPP offsite power supply:

   Note: With regard to Station Blackout(SB 0) DCPP 1 &2 are 4 hour coping plants. The regulatory requirement is that DCPP be able to withstand a loss of all AC power (loss of offsite power plus loss of both Emergency Diesel Generators) for 4 hours. Therefore, at least one transmission line into the DCPP switchyard should be restored within 4 hours to prevent possible core damage.

   a) Highest possible priority shall be given to restoring power to the DCPP switchyards.

   b) Should incoming lines to the DCPP switchyards be damaged, highest priority shall be assigned to repair and restoration of at least one line into the DCPP switchyards.

   c) Repair crews engaging in power restoration activities for DCPP shall be given the highest priority for manpower, equipment, and materials.

   d) Formal programs and procedures shall be in place to effect items a), b), and c) above.

9. Grid frequency shall be maintained at 60 Hertz (nominal). The following operations are initiated for low system frequency conditions:

    a) At 59.75 Hz, A- 18 interruptible customers are tripped.

    b) At 59. 1 Hz, PG&E system load shedding is initiated. Two 5% blocks (10%) of load is tripped at this frequency and at 0.2 Hz decrements until 50% of load has been tripped (10 5% blocks).

    c) At 58.2 Hz the north and south 500 kV intertie lines are tripped to separate the PG&E system from SCE and the Northwest systems.

    d) Thermal plants are equipped with 3 setpoint underfrequency relays that would cause underfrequency tripping to protect the turbines and generators from being damaged. The set points are:

       58 Hz with 3-minute time delay
       57 Hz with 1-minute time delay
       55 Hz with 0.5 seconds time delay

    e) Hydro generators are tripped last at 54.0 Hz with 1-minute time delay.

10. PG&E Bulk Power Transmission System Reliability Criteria as described in the DCPP Updated Final Safety Analysis Report shall be maintained. Changes to the reliability criteria that could adversely impact grid reliability and availability as defined in this specification require prior approval of PG&E.

11. PG&E transmission lines shall be patrolled annually to ensure that the physical and electrical integrity of transmission system components is maintained.

12. Line insulators, pole hardware terminals, and tower hardware terminal within the first three miles from the Diablo switchyard shall be washed and inspected at least three times a year to reduce line outages that may result from flashovers due to possible accumulated contamination.

13. Preventive maintenance, testing and calibration of DCPP switchyard circuit breakers and protective relays shall be performed as follows:

    PG&E: 230kV & 500kV circuit breakers are inspected every 2 years and overhauled every 8 years. Transmission line relays are tested every 36 months.

    Preventive maintenance and testing of DCPP switchyard batteries shall be performed per IEEE 450-1972. Preventive maintenance and testing of DCPP switchyard battery chargers and DC system components shall be performed every 3 months.

14. Updates to applicable portions of Section 8.0, Electric Power of DCPP 1&2 Updated Final Analysis Report (UFSAR) shall be provided annually. These updates will be used by PG&E to prepare a UFSAR change submittal to the NRC. DCPP is required

by 10CFR50.71(e) to submit to the NRC periodic updates to the UFSAR.

These Specific Requirements mirror existing operating protocols, equipment, regional and national reliability organization standards and are subject to modification as necessary when new standards, equipment or protocols are adopted or updated.

SONGS 2&3 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

Revised January 5, 1998

OVERVIEW

The preferred source of electrical power for SONGS electrical loads (safety-related and nonsafety-related) is the ***offsite power supply*** or 230 kV grid. The offsite power supply is sometimes referred to as the ***preferred power supply*** in the regulatory documents.

The basic requirement for the offsite power supply is that it provides ***sufficient capacity and capability*** to safely shut down the reactor and to mitigate certain specified accident scenarios. When this condition is met, the offsite power supply is considered Operable with respect to the SONGS Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If the offsite power system is declared Inoperable, action must be taken to shut down an online SONGS unit(s) and, for an offline unit, to suspend activities as required by the SONGS Operating License and Technical Specifications. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to supply electrical loads needed to safely shut down the reactor and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power unavailable to safely shutdown the units or to supply emergency electrical loads.

In specific terms, the offsite power supply voltage (at the SONGS switchyard) must stay within the range of 218 kV to 238 kV under all normal and plant accident (i.e. emergency shutdown or trip) conditions. Otherwise the offsite power supply is considered Inoperable. Since accident scenarios for which the plant is designed can result in a unit trip, it is imperative that the trip not impair the operability of the offsite power system. Therefore, following a trip of a SONGS unit (i.e., the unit breakers open), the SONGS switchyard voltage must recover to and be maintained at or above 218 kV within 2.5 seconds following the trip. If this condition cannot be met, then the offsite power supply is considered Inoperable, and action must be taken to shut down the operating SONGS unit(s). Even though these requirements apply at all times, this condition is primarily of concern when one SONGS unit is online and the other unit offline. If both SONGS units are online and one unit trips (due to an accident or otherwise), the non-tripped unit will provide local voltage support to the SONGS switchyard, and 230 kV system voltage will remain within the required range. In cases where one SONGS unit is online and one unit offline, the offsite power supply must be sufficiently robust to survive a trip of the online unit and meet the SONGS voltage requirements in the post-trip condition. A dual unit trip is not the limiting condition since a plant accident is not postulated simultaneous with a dual unit trip.

System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and communicated to the SONGS Control Room for Operability determination.

The SONGS switchyard is made up of the SCE switchyard and the SDG&E switchyard. Unless specifically stated otherwise, SONGS switchyard requirements contained in this document apply to both the SCE switchyard and the SDG&E switchyard.

SPECIFIC REQUIREMENTS

Note 1: This section identifies the operational requirements for the SONGS offsite power supply. These requirements are part of the SONGS design basis and licensing basis. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating SONGS unit(s) to shutdown. Failure to meet these requirements must be immediately

communicated to SCE and the SONGS Control Room for operability determination. Changes in the operation of the transmission network that conflict with these requirements require prior approval by SCE.

Note 2: Specific requirements, procedures, operating bulletins, division orders, and analysis that support or provide the basis for the specific operational requirements may be revised periodically subject to prior approval of the affected parties.

1. Nine transmission lines into the SONGS switchyard are normally in service. Any increase or decrease in the number of lines into the SONGS switchyard requires prior approval of SCE. (Reference 7)

   No line may be removed from service for greater than 30 days without prior notification to SCE. At least two independent transmission lines (one from SCE and one from SDG&E) between the transmission network (grid) and SONGS switchyard shall be in service at all times. (References 1, 2, 3, 4, 7, 8)

2. With both San Onofre units off-line, the SONGS offsite power source shall be capable of providing 152 MW and 96 MVAR to San Onofre for normal operation and for shutting down the units during plant Design Basis Accident (DBA) conditions. (References 9, 10)

3. The minimum grid voltage at the SONGS switchyard shall be maintained at or above 218 kV. In the event of a system disturbance that can cause the voltage to dip below 218 kV, including the trip of a SONGS unit, the grid voltage shall recover to 218 kV or above within 2.5 seconds. (References 9, 10, 12, 13, 18)

4. The following initiating events shall not result in the loss of grid stability or availability:

   a. The loss of a San Onofre Unit (with the other unit already offline), or

   b. The loss of any generating unit on the SCE and SDG&E grids, or

   c. The loss of any major transmission circuit or intertie on the SCE and SDG&E grids, or

   d. The loss of any large load or block of load (e.g., due to a bus section outage) on the SCE and SDG&E grids.

   (References 2, 3, 4, 8)

5. The maximum grid voltage at the SONGS switchyard shall be maintained at or below 238 kV. (References 10, 11, 18)

6. The normal operating voltage of the SONGS switchyard shall be maintained at 230 kV. The SONGS switchyard voltage shall not exceed 232 kV unless required to preserve transmission network integrity. (References 10, 11, 18)

7. The limiting conditions for SONGS offsite power source operability are defined as follows:

   1. One SONGS unit is off- line, and
   2. One of the critical line (s) outages occurs (see list of the lines below), and
   3. VAR flows north and south of SONGS are above the threshold levels for the existing combined SCE and SDG&E import level as defined by the referenced nomograms in the ECC Operating Procedure : SONGS Voltage, dated December 9, 1997.

   Based on these nomograms and SONGS offline unit's mode status if the ECC, Grid Control Center (GCC), or ISO determines that the operating point is outside the applicable derated import nomogram line, they shall notify SONGS immediately that a particular transmission line is out of service, and the critical system conditions are sufficient to cause SONGS off site power source to be considered INOPERABLE; i.e., unable to support SONGS voltage at 218 kV if the remaining unit trips. SONGS Control Room will declare the offsite source inoperable (in anticipation of losing the second SONGS unit) and will declare the time period within which the on-line unit will have to initiate shutdown if conditions are not corrected. The time period will be within 1 to 24 hours, based on the SONGS plant and equipment conditions.

List of the critical transmission lines:

Critical Line(s) Out In SCE Territory

Palo Verde -Devers 500 kV Line
Ellis- Johanna & Ellis-Santiago 230 kV Lines
Lugo-Serrano & Mira Loma-Serrano 500 kV Lines
Lugo- Mira Loma 2&3 500 kV Lines
Two Midway - Vincent 500 kV Lines
SONGS- Serrano & SONGS - Chino 230 kV Lines

Critical Line(s) Out in SDG&E Territory

Palo Verde- N. Gila 500 kV Line
N. Gila- Imperial Valley 500 kV Line
Imperial Valley- Miguel 500 kV Line
Imperial Valley- Miguel 500 kV Line & Imperial Valley- LaRosita 230 kV Line
SONGS-San Luis Rey 230 kV Tap & SONGS - Mission 230 kV Line

Systems studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions, such as the above cases, that could render the offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to provide electrical support to safe shutdown loads and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable for safe shutdown and emergency purposes. The following actions are required:

a. Procedures and programs shall be in effect to ensure that the SONGS Control Room is immediately notified of such conditions.

b. Grid conditions that are more severe with respect to SONGS switchyard voltage, or are otherwise unanalyzed, render the offsite power supply Inoperable. The SONGS Control Room shall be immediately notified of such conditions.

c. Auditable records of current system studies shall be made available to SCE as needed to demonstrate compliance with regulatory requirements. Study results, including revisions and updates, shall be formally transmitted to SCE.

d. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be formally transmitted to SCE.

(References 1, 2, 19, 21)

System studies shall consider the interconnections between SCE, SDG&E, and other utilities in the Western Systems Coordinating Council (WSCC) region. (Reference 7)

8. In the event of loss of the SONGS offsite power supply:

Note: SONGS 2 and 3 are required by NRC regulations to be able to safely cope with a loss of all AC power (Station Blackout) for a maximum of four hours. The four hour coping duration is based on the expectation that at least one source of AC power (offsite transmission line or onsite diesel generator) will be restored to the blacked-out unit within the four hours to ensure the proper functioning of systems required for plant safety.

a. Highest possible priority shall be given to restoring power to the SONGS switchyard. Procedures and training should consider several potential methods of transmitting power from black-start capable units to the SONGS switchyard. This includes such items as nearby gas turbine generators, portable generators, hydro generators, and black-start fossil power plants. (References 15, 26, 28)

b. Should incoming lines to the SONGS switchyard be damaged, highest priority shall be assigned to repair and restoration of at least one line into the SONGS switchyard.

c. Repair crews engaging in power restoration activities for SONGS shall be given the highest priority for manpower, equipment, and materials.

d. Formal programs and procedures shall be in place to effect items a, b, and c above.

(References 14, 15, 16, 17, 26, 27)

9. Grid frequency shall be maintained at 60 Hertz (nominal). A trip of one SONGS unit shall not cause the grid frequency to dip below 59.7 Hertz. The following operations are initiated for low system frequency conditions:

   a. At 59.3 Hertz, SCE system load shedding program is initiated.

   b. At 58.2 Hertz, automatic separation of the SCE system from the SDG&E system is initiated at the SONGS switchyard when either San Onofre unit is pre-selected to separate with the SDG&E system.

   c. At 58.0 Hertz, manual separation of the SCE system from the SDG&E system is initiated at the SONGS switchyard when either San Onofre unit is pre-selected to separate with the SDG&E system.

   d. At 57.0 Hertz, automatic separation of the SCE system from the SDG&E system is initiated at the SONGS switchyard when no San Onofre unit is selected to separate with the SDG&E system.

   e. At 56.8 Hertz, manual separation of the SCE system from the SDG&E system is initiated at the SONGS switchyard when no San Onofre unit is selected to separate with the SDG&E system.

   Note: The above separation setpoints are provided for information only. SCE and SDG&E are currently reviewing the 57 Hz separation setpoint. This setpoint may be changed to ensure that system separation occurs prior to a trip of the nuclear unit(s), which also occurs at approximately 57 Hz. SCE will inform the ISO of any changes to the system separation setpoint.

(References 7, 20)

10. SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report shall be maintained. It is recognized that the SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report may be revised from time to time. In the event the reliability criteria are revised, a system assessment and/or study (as described under specification 7) shall be performed to determine if the revised reliability criteria adversely impact grid reliability and availability as defined in this specification. Results of the assessment and/or study together with a copy of the revised reliability criteria shall be provided to SCE. Changes in grid operation based on the revised criteria and associated studies shall not be implemented without prior approval of SCE. (Reference 7)

11. SCE and SDG&E transmission lines shall be patrolled annually to ensure that the physical and electrical integrity of transmission system components is maintained. (References 7, 22)

12. Line insulators, pole hardware terminals, and tower hardware terminals within the first three miles from the San Onofre switchyard shall be inspected annually and washed at least two times a year to reduce line outages that may result from flashovers due to possible accumulated contamination. (References 7, 22)

13. Preventive maintenance, testing and calibration of SONGS switchyard circuit breakers and protective relays shall be performed as follows:

    SCE: 230 kV circuit breakers are overhauled every 300 normal operations or 25 kickouts. Response time/trip testing is performed annually. Transmission line relays are tested biannually. (References 7, 24, 25)

    SDG&E: 230 kV circuit breakers are overhauled every five years. Trip testing is performed annually. Transmission line relays are tested biannually. (Reference 7)

14. Preventive maintenance and testing of SONGS switchyard batteries shall be performed per IEEE 450-1972. Preventive maintenance and testing of SONGS switchyard battery chargers and DC system components shall be performed routinely. (Reference 7, 23)

15. Updates to applicable portions of Section 8.0, Electric Power of the SONGS 2 & 3 Updated Final Safety Analysis Report (UFSAR) shall be provided annually. These updates will be used by SCE to prepare a UFSAR change submittal to the NRC. SONGS is required by 10CFR50.71(e) to submit to the NRC periodic updates to the UFSAR.

REFERENCES

1) SONGS 2&3 Operating License and Technical Specifications, Section 3.8, Electrical Power Systems

2) 10CFR50 Appendix A, General Design Criterion 17 (GDC-17), Electrical Power Systems

3) NUREG 75/087, Standard Review Plan Revision 1, Section 8.2, Offsite Power System

4) NUREG 0800, Standard Review Plan Revision 2, Section 8.2, Offsite Power System

5) NUREG 0800, Standard Review Plan Revision 2, Branch Technical Position ICSB-11 (PSB), Stability of Offsite Power Systems

6) NUREG 0712, SONGS 2&3 Safety Evaluation Report, Section 8.0, Electric Power Systems

7) SONGS 2 & 3 Updated Final Safety Analysis Report, Section 8.0, Electric Power

8) ANSI/IEEE Std. 765-1983 Preferred Power Supply for Nuclear Power Generating Stations

9) SONGS Design Calculation E4C-082, System Dynamic Voltages During Design Basis Accident

10) SONGS Design Calculation E4C-090, Auxiliary System Voltage Regulation

11) SONGS Design Calculation E4C-092, Short Circuit Studies

12) SONGS Design Calculation E4C-098, 4 kV Swgr Protective Relay Setting

13) DBD-SO23-120, SONGS Design Basis Document, 6.9KV, 4.16KV and 480V Electrical Systems

14) 90051, SONGS Station Blackout Analyses

15) NUMARC 87-00 Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors

16) Letter from M. 0. Medford (SCE) to the Document Control Desk (NRC), dated April 17, 1989, Subject: "Response to 10 CFR 50.63, `Loss of all Alternating Current Power,' San Onofre Nuclear Generating Station Units 1, 2 and 3"

17) Letter from F. R. Nandy (SCE) to the Document Control Desk (NRC), dated May 1, 1990, Subject: "Supplemental Response to 10 CFR 50.63, 'Loss of All Alternating Current Power,' Station Blackout (TAC No. 68599/600), San Onofre Nuclear Generating Station Units 1, 2, and 3"

18) System Operating Bulletin 17 Appendix, System Voltage Control for San Onofre Nuclear Generating Station (Rev. January, 1998)

19) ECC Operating Procedure: Songs Voltage (Rev. 12/09/1997)

20) System Operating Bulletin 113, San Onofre 220 kV System Separation (Rev. April 15, 1995)

21) Regulatory Guide 1.93, Availability of Electric Power Sources

22) SCE Division Order 40.35, Transmission Line Routine Patrol, Inspection, Scheduling, and Record Keeping (Rev. 10/87)

23) SCE Division Order 60.20, Storage Batteries (Rev. 3/82)

24) SCE Division Order 50.10, Predictive Maintenance Circuit Breakers and Switches (Rev. 6/96)

25) SCE Division Order 50.20, Relay and Equipment Tests (Rev. 3/94)

26) System Operating Bulletin 1-A, Thermal Station Start-up and Power System Restoration (Rev. 12/97)

27) System Operating Bulletin 254, Emergency Orders—San Onofre Nuclear Generating Station 220 kV (Rev. March 18, 1996)

28) SDG&E Control Procedure 1150, Capacity & Energy Emergencies - SDG&E System Emergencies (Rev. 12/97)

EXHIBIT 3

agreements. The New Participating TO shall assume responsibility for paying all Scheduling Coordinators charges regardless of whether the New Participating TO elects to become a Scheduling Coordinator or obtains the services of a Scheduling Coordinator.

3.2 Transmission Expansion.

A Participating TO shall be obligated to construct all transmission additions and upgrades within its PTO Service Area that are determined to be needed in accordance with the requirements of this Section 3.2. A Participating TO's obligation to construct such transmission additions and upgrades shall be subject to: (1) its ability, after making a good faith effort, to obtain all necessary approvals and property rights under applicable federal, state, and local laws and (2) the presence of a cost recovery mechanism with cost responsibility assigned in accordance with Section 3.2.7. The obligations of the Participating TO to construct such transmission additions or upgrades will not alter the rights of any entity to construct and expand transmission facilities as those rights would exist in the absence of the TO's obligations under this ISO Tariff or as those rights may be conferred by the ISO or may arise or exist pursuant to this ISO Tariff.

3.2.1 Determination of Need.

A Participating TO or any other Market Participant may propose a transmission system addition or upgrade. The ISO will determine that a transmission addition or upgrade is needed where it will promote economic efficiency or maintain system reliability as set forth below.

3.2.1.1 Economically Driven Projects. The Participating TO and Market Participants shall provide the necessary assistance and information to the ISO, as part of the coordinated planning process, to enable the ISO to determine that a project is needed to promote economic efficiency, including, at the ISO's discretion, studies comporting with ISO guidelines that demonstrate whether the project will promote economic efficiency or the information the ISO requires to carry out its own studies for economically driven projects. The ISO shall treat market sensitive information provided to the ISO in accordance with this Section by Participating TOs, Project Sponsors and applicable Market Participants confidentially in accordance with Section 20.3 provided that such information is clearly marked "Confidential" at the time it is provided to the ISO. The determination that a transmission addition or upgrade is needed to promote economic efficiency shall be made in any of the following ways:

3.2.1.1.1 If the Participating TO or any party questions the economic need for the project (except where the Project Sponsor commits to pay the full cost of construction) the proposal will be submitted to the ISO ADR Procedures for resolution.

3.2.1.1.2 Where a Project Sponsor other than the Participating TO commits to pay the full cost of construction of a transmission addition or upgrade and its operation, and demonstrates to the ISO financial capability to pay those costs, such commitment and demonstration shall be sufficient to demonstrate need to the ISO. To ensure that the Project Sponsor is financially able to pay the costs of the project to be constructed by the Participating TO, the Participating TO may require (1) a demonstration of creditworthiness (e.g. an appropriate credit rating), or (2) sufficient security in the form of an unconditional and irrevocable letter of credit or other similar security sufficient to meet its responsibilities and obligations for the full costs of the transmission addition or upgrade.

3.2.1.1.3 Where a Project Sponsor asserts that a transmission addition or upgrade is economically beneficial, but that Project Sponsor is unwilling to commit to pay the full cost of the addition or upgrade; where (1) the proposed transmission addition or upgrade was submitted to the Participating TO but was not included in the transmission expansion plan of that Participating TO in accordance with Section 3.2.2 or (2) the operation date of the planned expansion is not acceptable to the ISO or the Project Sponsor or (3) the Participating TO unreasonably delays implementing or subsequently decides not to proceed with the project, the Project Sponsor may submit its proposal to the ISO ADR Procedure for determination of need. A determination of need shall be made as follows:

3.2.1.1.3.1 The Project Sponsor shall include in its proposal: (1) a showing that the economic benefits of the proposed transmission addition or upgrade are expected to exceed its costs (giving consideration to any reasonable alternatives to the construction of transmission additions or upgrades) using an economic analysis that comports with ISO guidelines, and (2) a statement of the proposed pricing methodology for the transmission upgrades or additions that the Project Sponsor elects in accordance with Section 3.2.7 of the ISO Tariff.

3.2.1.1.3.2 If neither any Market Participant nor the ISO disputes the Project Sponsor's showing, then the proposal is determined to be needed.

3.2.1.1.3.3 If any Market Participant or the ISO disputes the Project Sponsor's showing, the disputing Market Participant, the ISO, or the Project Sponsor may submit to resolution through the ISO ADR Procedure the issue of whether the transmission addition or upgrade is needed on the ground that its economic benefits exceed its costs. If a Market Participant fails to raise through the ISO ADR Procedure a dispute as to whether a proposed transmission addition or upgrade is needed, then the Market Participant shall be deemed to have waived its right to raise such dispute at a later date. The determination under the ISO ADR Procedure as to whether the transmission addition or upgrade is needed, including any determination by FERC or on appeal of a FERC determination in accordance with that process, shall be final.

3.2.1.2 Reliability Driven Projects. The ISO in coordination with the Participating TO, will identify the need for any transmission additions or upgrades required to ensure system reliability consistent with all Applicable Reliability Criteria. In making this determination, the ISO, in coordination with the Participating TO and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, remedial action schemes, constrained-on Generation, interruptible Loads or reactive support. The Participating TO, in cooperation with the ISO, shall perform the necessary studies to determine the facilities needed to meet all Applicable Reliability Criteria. The Participating TO shall provide the ISO and other Market Participants with all information relating to a proposed transmission addition or upgrade that they may reasonably request (other than information available to them through the WSCC or any other applicable regional organization) and shall, through the WSCC or any other applicable regional organization coordinated planning processes, develop the scope of and assumptions for such studies that are acceptable to the ISO and those other Market Participants. The ISO shall be free to propose any transmission upgrades or additions it deems necessary to ensure System Reliability consistent with Applicable Reliability Criteria, and, subject to appropriate appeals, the Participating TO shall be obligated to construct such lines. After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs and MSSs, will work to develop a consistent set of reliability criteria for the ISO Controlled Grid which the Participating TOs will use in their transmission planning and expansion studies or decisions.

3.2.2 Transmission Planning and Coordination.

The ISO shall actively participate with each Participating TO and the other Market Participants in the ISO Controlled Grid planning process in accordance with the terms of this ISO Tariff and the Transmission Control Agreement.

3.2.2.1 Each Participating TO shall develop annually a transmission expansion plan covering a minimum five-year planning horizon for its PTO Service Area. Such Participating TO shall coordinate with the ISO and other Market Participants in the development of such plan. The Participating TO shall be responsible for ensuring that its transmission expansion plan meets all Applicable Reliability Criteria.

3.2.2.2 The ISO shall review the Participating TOs' transmission expansion plans to ensure that each Participating TO's expansion plans meet the Applicable Reliability Criteria. The Participating TO will provide the necessary assistance and information as part of the coordinated planning process to the ISO to enable it to carry out its own studies for these purposes. If the ISO finds that the Participating TO's plan or projects do not meet the Applicable Reliability Criteria, the ISO will provide comments and the Participating TO will reassess its plans, as appropriate. The ISO may also propose new projects or suggest project changes (*e.g.*, timing, project size) for consideration by the Participating TO. Changes or additions made by the ISO and accepted by the TO will be included in the Participating TO's expansion plan. Changes or additions not accepted in the coordinated planning process will be resolved through the ISO ADR Procedure.

3.2.2.3 The Participating TO will act as a Project Sponsor for Participating TO proposed economic or reliability projects that are included in its expansion plan. The Participating TO shall provide to the ISO any information that the ISO requires to enable the ISO to comply with WSCC and any other applicable regional coordination requirements pursuant to Section 3.2.6.

3.2.2.4 The ISO will be a member of the WSCC and other applicable regional organizations and participate in WSCC's operation and planning committees, and in other applicable regional coordinated planning processes. No Participating TO, Market Participant nor the ISO shall take any position before the WSCC or a regional organization that is inconsistent with a binding decision reached through the ISO ADR Procedure.

3.2.3 Studies to Determine Facilities to be Constructed.

Where a Participating TO is obligated to construct or expand facilities in accordance with this ISO Tariff or where the ISO or any Market Participant requests that a Facility Study be carried out, the Participating TO (in coordination with the ISO or the relevant Market Participants as the case may require), shall perform the necessary study or studies to determine the appropriate facilities to be constructed in accordance with the terms set forth in the TO Tariff. The scope of and assumptions for any studies requested by a Project Sponsor of a transmission addition or upgrade on economic grounds must be acceptable to the Project Sponsors and the ISO. Any dispute relating to a Facility Study Agreement (including any dispute over the scope of the study or its assumptions) shall be resolved through the ISO ADR Procedures.

3.2.4 Operational Review.

The ISO will perform an operational review of all facilities that are to be connected to, or made part of, the ISO Controlled Grid to ensure that the facilities being proposed provide for acceptable operating flexibility and meet all its requirements for proper integration with the ISO Controlled Grid. If the ISO finds that such facilities do not provide for acceptable operating flexibility or do not adequately integrate with the ISO Controlled Grid, the Participating TO will reassess its determination of the facilities required to be constructed.

3.2.5 State and Local Approval and Property Rights.

3.2.5.1 The Participating TO shall be obligated to make a good faith effort to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this ISO Tariff. This obligation includes the Participating TO's use of eminent domain authority, where provided by state law.

3.2.5.2 If the Participating TO cannot secure any such necessary approvals or property rights and consequently is unable to construct a transmission addition or upgrade, it shall promptly notify the ISO and the Project Sponsor and shall comply with its obligations under the TO Tariff to convene a technical meeting to evaluate alternative proposals. The ISO shall take such action as it reasonably considers appropriate, in coordination with the Participating TO, the Project Sponsor (if any) and other affected Market Participants, to facilitate the development and evaluation of alternative proposals including, where possible, conferring on a third party the right to build the transmission addition or upgrade.

3.2.5.3 Where it is possible for a third party to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this ISO Tariff (including the use of eminent domain authority, where provided by state law) the ISO may confer on a third party the right to build the transmission addition or upgrade which shall enter into the Transmission Control Agreement in relation to such transmission addition or upgrade.

3.2.6 WSCC and Regional Coordination.

The Project Sponsor will have responsibility for completing any applicable WSCC requirements and other applicable regional coordination and rating study requirements to ensure that a proposed transmission addition or upgrade meets regional planning requirements. The Project Sponsor may request the Participating TO to perform this coordination on behalf of the Project Sponsor at the Project Sponsor's expense.

3.2.7 Cost Responsibility for Transmission Additions or Upgrades.

Cost responsibility for transmission additions or upgrades constructed pursuant to this Section 3.2 (including the responsibility for any costs incurred under Section 3.2.6) shall be determined as follows:

3.2.7.1 Where a Project Sponsor commits to pay the full cost of a transmission addition or upgrade as set forth in Section 3.2.1.1.2, the full costs shall be borne by the Project Sponsor.

3.2.7.2 Where the need for a transmission addition or upgrade is determined by the ISO or as a result of the ISO ADR Procedure as set forth in Section 3.2.1.1.3, the cost of the transmission addition or upgrade shall be borne by the Participating TO that will be the owner of the transmission addition or upgrade and shall be reflected in its Transmission Revenue Requirement.

3.2.7.3 Provided that the ISO has Operational Control of the transmission upgrade or addition, a Project Sponsor that does not recover the investment cost under a FERC-approved rate through the Access Charge or a reimbursement or direct payment from a Participating TO shall be entitled to receive:

(a) its share, as determined in subsection (d) below, of the Wheeling revenues attributable to the transmission addition or upgrade;

(b) its share, as determined in subsection (d) below, of the proceeds of the FTR auction for FTRs defined on the Inter-Zonal Interface of which the transmission addition or upgrade forms a part as set forth in Section 9.5.3, provided that the Project Sponsor does not receive FTRs from the ISO in accordance with Section 9.4.3 of the ISO Tariff; and

(c) its share, as determined in subsection (d) below, of the Congestion revenues provided as calculated pursuant to Section 7.3.1.6 on the Inter-Zonal Interface of which the transmission addition or upgrade forms a part.

(d) The Project Sponsor's share of Wheeling, Congestion and FTR auction revenues for the upgraded transmission facility shall be the number that is determined by dividing the number that is determined by subtracting the rating of the transmission facility before the upgrade from the new rating for the upgraded transmission facility by the new rating for the upgraded transmission facility. The Participating TO's share of Wheeling, Congestion and FTR auction revenues for the upgraded transmission facility shall be the number that is determined by subtracting the Project Sponsor's share from one hundred percent (100%). Such allocated shares shall become effective on the date the new rating takes effect. The full amount of capacity added to the system will be based on the physical addition to the transfer capability as determined through the regional reliability council process of the Western Electricity Coordinating Council or its successor.

3.2.7.4 Once a New Participating TO has executed the Transmission Control Agreement and it has become effective, the cost for New High Voltage Facilities for all Participating TOs shall be included in the ISO Grid-wide component of the High Voltage Access Charge in accordance with Schedule 3 of Appendix F. The

Participating TO who is supporting the cost of the New High Voltage Facility shall include such costs in its High Voltage Transmission Revenue Requirement, regardless of which TAC Area the facility is geographically located.

3.2.8 Ownership of and Charges for Expansion Facilities.

3.2.8.1 All transmission additions and upgrades constructed in accordance with this Section 3.2 shall form part of the ISO Controlled Grid and shall be operated and maintained by a Participating TO in accordance with the Transmission Control Agreement.

3.2.8.2 Each Participating TO that owns or operates transmission additions and upgrades constructed in accordance with this Section 3.2 shall provide access to them and charge for their use in accordance with this ISO Tariff and its TO Tariff.

3.2.9 Expansion by "Local Furnishing" Participating TOs.

Notwithstanding any other provision of this ISO Tariff, a Local Furnishing Participating TO shall not be obligated to construct or expand facilities, (including interconnection facilities as described in Section 8 of the TO Tariff) unless the ISO or Project Sponsor has tendered an application under FPA Section 211 that requests FERC to issue an order directing the Local Furnishing TO to construct such facilities pursuant to Section 3.2 of the ISO Tariff. The Local Furnishing TO shall, within 10 days of receiving a copy of the Section 211 application, waive its right to a request for service under FPA Section 213(a) and to the issuance of a proposed order under FPA Section 212(c). Upon receipt of a final order from FERC that is no longer subject to rehearing or appeal, such Local Furnishing TO shall construct such facilities in accordance with this Section 3.2.

5.7 Interconnection of New Facilities to the ISO Controlled Grid.

5.7.1 Applicability.

For purposes of this Section 5.7, a New Facility shall be:

(a) each Generating Unit that seeks to interconnect to the ISO Controlled Grid;

(b) each existing Generating Unit connected to the ISO Controlled Grid that will be re-powered and increase the total capability of the power plant; and

(c) each existing Generating Unit connected to the ISO Controlled Grid that will be re-powered without increasing the total capability of the power plant but has changed the electrical characteristics of the power plant such that its re-energization may violate Applicable Reliability Criteria and trigger the application of Section 5.7.5(c).

The owner of a planned New Facility, or its designee, is referred to for purposes of this Section 5.7 as a New Facility Operator. Only New Facility Operators that have not submitted a Completed Interconnection Application, as defined under the applicable Interconnecting PTO's TO Tariff, to the Interconnecting PTO as of the effective date of this Section 5.7 are subject to its provisions.

5.7.2 Requests to Interconnect to the Distribution System.

Any request by a New Facility Operator to connect at distribution level voltage will be processed, as applicable, pursuant to the Wholesale Distribution Access Tariff of the Interconnecting PTO or CPUC Rule 21; provided, however, that the New Facility Operator shall be required to mitigate any adverse impact on reliability on the ISO Controlled Grid in accordance with Section 5.7.5. In addition, each Interconnecting PTO will provide to the ISO a copy of the System Impact Study used to determine the impact of a New Facility on the Distribution System and the ISO Controlled Grid pursuant to a request to interconnect under the applicable Wholesale Distribution Access Tariff.

5.7.3 Interconnection Application.

All New Facility Operators shall submit two copies of a Completed Interconnection Application to the ISO in the form specified by the ISO. The ISO will date stamp all copies of the

Interconnection Application, retain one executed copy, and, within 1 Business Day, send the other copy to the Designated Contact Person of the Interconnecting PTO. Within 10 Business Days after the Interconnecting PTO receives an Interconnection Application, the ISO and the Interconnecting PTO shall determine whether the application is complete and the ISO will notify the New Facility Operator that its Interconnection Application is complete; or, in the event that the ISO, in consultation with the Interconnecting PTO, determines that the Interconnection Application is incomplete, the ISO will notify the New Facility Operator of the deficiencies or omissions in its application.

5.7.3.1 Expedited Procedures For New Facilities.

A New Facility Operator may submit a Request for Expedited Interconnection Procedures in accordance with Section 5.7.3.1.1. The ISO will develop and post on the ISO Home Page the Planning Procedures applicable to such expedited processing of Interconnection Applications.

5.7.3.1.1 Request for Expedited Interconnection Procedures.

(a) If it elects to expedite processing of its Completed Interconnection Application, a New Facility Operator shall submit a Request for Expedited Interconnection Procedures within 10 Business Days after receiving a copy of the System Impact Study for the proposed interconnection. The request should be submitted in writing to the ISO and the Interconnecting PTO.

(b) Within 10 Business Days after receiving a Request for Expedited Interconnection Procedures, the ISO and Interconnecting PTO shall provide to applicant the results of any studies required in addition to the System Impact Study, and shall tender an Expedited Interconnection Agreement that requires the applicant to compensate the Interconnecting PTO for all costs reasonably incurred pursuant to the terms of the ISO Tariff and the Interconnecting PTO's applicable TO Tariff for processing the Completed Interconnection Application and providing the requested interconnection.

(c) Concurrent with the provision, by the ISO and the Interconnecting PTO, of the studies referenced in subsection b, above, the Interconnecting PTO and the ISO shall provide to applicant their best estimate of the cost of any needed Direct Assignment Facilities and Reliability Upgrades, Delivery Upgrades, if requested by the New Facility Operator, and other costs that may be incurred in processing the Interconnection Application and providing the requested interconnection, however, unless otherwise agreed by the ISO, and the Interconnecting PTO, and the applicant, such cost estimate shall not be binding and the New Facility Operator shall compensate the ISO and the Interconnecting PTO for all actual interconnection costs reasonably incurred pursuant to the provisions of this Section 5.7 and the Interconnecting PTO's TO Tariff.

(d) The New Facility Operator shall execute and return to the Interconnecting PTO, with a copy to the ISO, such Expedited Interconnection Agreement within 10 Business Days of its receipt or the New Facility Operator's Interconnection Application will be deemed withdrawn. In that event, the New Facility Operator shall reimburse the ISO and the Interconnecting PTO for all costs reasonably incurred in the processing of the Interconnection Application, including the Request for Expedited Interconnection.

5.7.3.2 Good Faith Deposit.

(a) Each New Facility Operator that submits an Interconnection Application will on the date of submission also provide a Good Faith Deposit to the ISO. The ISO shall hold the Good Faith Deposit in trust for each applicant in a separate, interest-bearing account.

(b) The ISO shall refund the Good Faith Deposit, with accrued Interest, in the event that:

(i) The ISO determines that the New Facility is not responsible for any interconnection costs, other than study costs; or

(ii) The applicant withdraws its Interconnection Application or its Interconnection Application is deemed withdrawn.

5.7.3.3 Posting of Interconnection Applications and Non-disclosure.

The ISO will maintain on its OASIS site an updated list of all pending Interconnection Applications. As soon as practicable after the ISO receives a Completed Interconnection Application, the ISO will post the nearest substation, the capacity (MW) of the New Facility and the year the New Facility is proposed to begin operations. At the time it submits its Interconnection Application, a New Facility Operator may request in writing that the ISO and Interconnecting PTO not publicly disclose the identity of such New Facility Operator. Upon such request, the ISO and Interconnecting PTO will not disclose the identity of the applicant while its Interconnection Application is pending, unless disclosure is permitted under Section 20.3.1 or in the event that an applicant's identity becomes otherwise publicly known.

5.7.4 Interconnection.

5.7.4.1 Detailed Planning Procedures.

The provisions set forth in this Section 5.7 shall govern the interconnection of New Facilities to the ISO Controlled Grid, including the costs of such interconnection. The ISO shall also maintain on the ISO Home Page detailed Planning Procedures and interconnection standards for all such interconnections. The ISO will develop, and post on the ISO Home Page, detailed procedures for updating the Planning Procedures.

5.7.4.2 Studies.

(a) Except as provided in Section 5.7.4.2(d), for each Completed Interconnection Application, the ISO will direct the Interconnecting PTO to perform the required System Impact Study and Facility Study, and any additional studies the ISO determines to be reasonably necessary.

(b) The Interconnecting PTO will complete or cause to be completed all studies directed by the ISO within the timelines provided in this section. Any studies performed by the ISO or by a third party at the direction of the ISO shall also be completed within the timelines provided in this section.

(c) Each New Facility Operator shall pay the reasonable costs of all System Impact and Facility Studies performed by or at the direction of the ISO or the Interconnecting PTO, and any additional studies the ISO determines to be reasonably necessary in response to the Interconnection Application, including any iterative study costs required for other New Facility Operator's that have established a new queue position due to the New Facility Operator either withdrawing its Interconnection Application or because its queue position has been modified pursuant to the procedures in Section 5.7.4.4. A New Facility Operator shall also pay the reasonable cost of Interconnecting PTO review of any System Impact Study or Facility Study that is performed by a New Facility Operator or its designee pursuant to subsection (d).

(d) A New Facility Operator may perform its own System Impact Study and Facility Study, or contract with a third party to perform the System Impact Study and Facility Study, and shall so notify the ISO and the Interconnecting PTO of this election at the time it submits its Interconnection Application. Any such study or studies performed by a New Facility Operator or third party must be completed within the timelines identified in Sections 5.7.4.2.1 and 5.7.4.2.2. To the extent that the ISO and Interconnecting PTO disagree on the adequacy of the New Facility Operator or third party-sponsored study, the ISO will determine the adequacy of the study, subject to the ISO's ADR Procedures. The ISO and Interconnecting PTO shall complete their review of the New Facility Operator's study within 30 calendar days of receipt of the completed study. The results of any study or studies performed by a New Facility Operator or third party must be approved by both the ISO and the Interconnecting PTO.

5.7.4.2.1 System Impact Study Procedures.

Within 10 Business Days after receiving a Completed Interconnection Application by the Interconnecting PTO, the ISO and the Interconnecting PTO will determine, on a non-discriminatory basis, whether a System Impact Study is required. The ISO and the Interconnecting PTO will make such determination based on the ISO Grid Planning Criteria and the transmission assessment practices outlined in the ISO Planning Procedures posted on the ISO Home Page. The ISO and Interconnecting PTO will utilize, to the extent possible, existing transmission studies. The System Impact Study will identify whether any Direct Assignment Facilities and Reliability Upgrades are needed, as well as, if requested by the New Facility Operator, any Delivery Upgrades necessary to deliver a New Facility's full output over the ISO Controlled Grid. The System Impact Study will also identify any adverse impact on Encumbrances existing as of the Completed Application Date.

If the ISO and the Interconnecting PTO determine that a System Impact Study is necessary, the Interconnecting PTO shall within 20 Business Days of receipt of Completed Interconnection Application, tender a System Impact Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time required to complete it, and pursuant to which the applicant shall agree to reimburse the Interconnecting PTO for the reasonable actual costs of performing the required study. The New Facility Operator shall execute the System Impact Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the System Impact Study. Alternatively, a New Facility Operator can request that the Interconnecting PTO proceed with the System Impact Study and abide by the terms, conditions, and cost assignment of the System Impact Study Agreement as determined through the ISO ADR Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the System Impact

Study. If a New Facility Operator elects neither to execute the System Impact Study Agreement nor to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Interconnection Application.

The Interconnecting PTO will use due diligence to complete the System Impact Study within 60 Calendar Days of receipt of payment and the System Impact Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the System Impact Study within 60 Calendar Days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

5.7.4.2.2 Facility Study Procedures.

If a System Impact Study indicates that additions or upgrades to the ISO Controlled Grid are needed to satisfy a New Facility Operator's request for interconnection, the Interconnecting PTO shall, within 15 Business Days of the completion of the System Impact Study, tender to a New Facility Operator a Facility Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time to complete the required study, and pursuant to which the applicant agrees to reimburse the Interconnecting PTO for the actual costs of performing the required Facility Study. The New Facility Operator shall execute the Facility Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. Alternatively, a New Facility Operator may request that the Interconnecting PTO proceed with the Facility Study and abide by the terms, conditions, and cost assignment of the Facility Study Agreement ultimately determined through the ISO ADR

Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. If a New Facility Operator elects either to not execute the Facility Study Agreement or to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Application.

The Interconnecting PTO will use due diligence to complete the Facility Study within 60 Calendar Days of receipt of payment and the Facility Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the Facility Study within 60 Calendar Days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

A New Facility Operator shall be entitled to amend its Completed Interconnection Application once without losing its queue position. Such amendment shall occur on or before 10 Business Days following the Date the Interconnecting POT tenders a Facility Study Agreement.

Specifically, as an alternative to executing and returning a Facility Study Agreement, a New Facility Operator may submit an amendment to its Completed Interconnection Application to reflect a revised configuration for its New Facility. The amended Completed Interconnection Application shall be treated in accordance with Section 5.7.4.2.1 and the New Facility operator's Completed Interconnection Application shall not be deemed withdrawn, and it shall maintain its exiting queue position, if (a) the amended Completed Interconnection Application is received by the Interconnecting PTO within 10 Business Days of the Interconnecting PTO's tender of a Facility Study Agreement; and (b) the New Facility Operator has not submitted a previous amendment to the Completed Interconnection Application. In the event a New Facility Operator amends its Completed Interconnection Application, it will be responsible for any additional study costs that result from that amendment, including costs associated with revisions to studies for other applicants holding later queue positions.

5.7.4.3 Execution of Interconnection Agreement.

Within 10 Business Days of receipt of a completed Facility Study, a New Facility Operator shall request the Interconnecting PTO to provide to such applicant an Interconnection Agreement. The Interconnecting PTO shall provide an Interconnection Agreement to an applicant within 30 Business Days of receipt of the request for an Interconnection Agreement. If the ISO and Interconnecting PTO determine, pursuant to Sections 5.7.4.2.1, that either:

(a) a New Facility Operator's Interconnection Application can be accommodated and that such New Facility Operator will not incur costs for Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 10 Business Days of receipt of the Interconnection Agreement; or

(b) a New Facility Operator's Interconnection Application will necessitate Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 30 Business Days of receipt of the Interconnection Agreement or, if a New Facility Operator and the Interconnecting PTO are unable to agree on the rates, terms and conditions of the Interconnection Agreement, the New Facility Operator may request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC. If a New Facility Operator does request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC, the New Facility Operator shall agree to abide by the rates, terms and conditions of such Interconnection Agreement ultimately determined by FERC to be just and reasonable.

5.7.4.4 Queuing.

(a) The ISO and Interconnecting PTO will process all Interconnection Applications based on the New Facility's Completed Application Date.

(b) The queue position for each New Facility that has submitted an Interconnection Application will be established according to the Completed Application Date and the New Facility's compliance with the milestones set forth in Section 5.7.4.4.1.

(c) For any New Facility Operator that has submitted a request to interconnect to a Interconnecting PTO prior to the date that FERC makes Section 5.7 effective, such New Facility Operator's position in the queue will be based on its Completed Application Date as that term was defined in the Interconnecting PTOs TO Tariff in effect at the time the New Facility Operator submitted a request to interconnect to the Interconnecting PTO.

5.7.4.4.1 Queuing Milestones.

(a) To maintain its queue position, each New Facility Operator must timely comply with the requirements of the ISO Tariff and the TO tariff of the Interconnecting PTO and must, within 6 months of its Completed Application Date, satisfy all applicable Data Adequacy Requirements of state and local siting and other regulatory authorities. Any New Facility Operator not subject to state siting requirements must satisfy the information requirements set forth in 18 C.F.R. §2.20. The ISO will permit a New Facility Operator to retain its queue position if such New Facility Operator requests an extension of the six-month period at least 5 Business Days prior to the expiration of such period. Such extension will be limited to one period of 30 Business Days and additional extensions shall not be granted. A New Facility Operator that does not maintain its queue position, but later satisfies the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, will be placed in a queue position comparable to that of other New Facility Operators that have satisfied the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20, as of the same date. At that time, the ISO and the Interconnecting PTO will determine whether a new System Impact Study must be performed based on the revised queue position of such New Facility Operator.

(b) Upon satisfaction of the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, each New Facility Operator, in order to maintain its queue position, must obtain a New Facility License within 15 months after satisfying the Data Adequacy Requirements. A New Facility Operator that does not obtain a New Facility License within the allowed time and does not maintain its queue position, but later obtains a New Facility License, will be placed in a queue position comparable to other New Facility Operators that have satisfied comparable milestones as of that date.

(c) Any New Facility whose New Facility License or building permit expires or is rescinded will not maintain its queue position.

(d) A New Facility Operator that has submitted a dispute under Article 13 of the ISO Tariff regarding any part of this Section 5.7 may request that the presiding judge, arbitrator, or mediator of the dispute suspend its obligation to meet milestones in order to maintain its queue position. In the event such a suspension is granted, the New Facility Operator must satisfy the missed milestones specified in this Section 5.7.4.4.1 within 30 calendar days of the date the decision on the dispute becomes final.

5.7.4.5 Coordination of Critical Protective Systems.

New Facility Operators shall coordinate with the ISO, Participating TOs and UDCs to ensure that a New Facility Operator's Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with ISO Controlled Grid Critical Protective Systems and the protective systems of the Participating TOs and UDCs. The ISO and Participating TOs will make available all information necessary for a New Facility Operator to determine whether its Critical Protective Systems are compatible with those of the ISO, Participating TOs and UDCs. The ISO and New Facility Operators shall also coordinate with entities that own, operate or control facilities outside of the ISO Controlled Grid to ensure that a New Facility's Critical Protective Systems function on a coordinated and complementary basis with such entities Critical Protective Systems.

5.7.5 Cost Responsibility of New Facility Operators.

(a) Each New Facility Operator shall pay the costs of required studies in accordance with Section 5.7.4.2 and the costs identified in this Section 5.7.5. The ISO and Interconnecting PTO will provide each New Facility Operator an estimate of its total cost responsibility under this Section. A New Facility Operator shall be responsible for the actual costs of all Direct Assignment Facilities and Reliability Upgrades necessitated by its Completed Interconnection Application. The Interconnecting PTO will provide each New Facility Operator a detailed record of the actual costs assessed to it under this Section. A New Facility Operator may request the Interconnecting PTO to provide any additional information reasonably necessary to audit the actual costs the New Facility Operator is assessed.

(b) The ISO and Interconnecting PTO will process all Interconnection Applications, and determine the cost responsibility of each New Facility Operator based on the New Facility Operator's Completed Application Date or, if applicable, based on the queue position determined by the procedure described in Section 5.7.4.4.1(b). The ISO and Interconnecting PTO will process simultaneously all interconnection requests with the same Completed Application Date.

(c) Each New Facility Operator shall pay the costs of planning, installing, operating and maintaining the following facilities: (i) Direct Assignment Facilities, and, if applicable, (ii) Reliability Upgrades. In addition, each New Facility Operator shall implement all existing operating procedures necessary to safely and reliably connect the New Facility to the facilities of the Interconnecting PTO and to ensure the ISO Controlled Grid's conformance with the ISO Grid Planning Criteria, and shall bear all costs of implementing such operating procedures. The New Facility Operator shall be responsible for the costs of Reliability Upgrades only if the necessary facilities are not included in the ISO Controlled Grid Transmission Expansion Plan approved as of the New Facility Operator's Completed Application Date, or the date for the installation of a facility is advanced by the interconnection of the New Facility, in which case the New Facility Operator shall be responsible only for the incremental costs associated with the earlier installation of the facility.

(d) Each New Facility Operator may, at its own discretion, sponsor, pursuant to Section 3.2 of the ISO Tariff, any Delivery Upgrades.

5.7.5.1 Maintenance of Encumbrances.

No New Facility shall adversely affect the ability of the Interconnecting PTO to honor its Encumbrances existing as of the time a New Facility submits its Interconnection Application to the ISO. The Interconnecting PTO, in consultation with the ISO, shall identify any such adverse effect on its Encumbrances in the System Impact Study performed under Section 5.7.4.2.1. To the extent the Interconnecting PTO determines that the connection of the New Facility will have an adverse effect on Encumbrances, the New Facility Operator shall mitigate such adverse effect.

5.7.5.2 Settlement of Interconnection Costs.

Payment for Direct Assignment Facilities and Reliability Upgrades shall be made by the New Facility Operator to the Interconnecting PTO pursuant to the terms of payment set forth in the Interconnection Agreement between the parties.

5.7.6 Energization.

Neither the ISO nor the Interconnecting PTO shall be obligated to energize, nor shall the New Facility Operator be entitled to have its interconnection to the ISO Controlled Grid energized, unless and until an Interconnection Agreement has been executed, or filed at FERC pursuant to Section 5.7.4.3, and becomes effective and such New Facility Operator has demonstrated to the ISO's reasonable satisfaction that it has complied with all of the requirements of this Section 5.2.

5.8 Recordkeeping; Information Sharing.

5.8.1 Requirements for Maintaining Records.

Participating Generators shall provide to the ISO such information and maintain such records as are reasonably required by the ISO to plan the efficient use and maintain the reliability of the ISO Controlled Grid.

5.8.2 Providing Information to Generators.

The ISO shall provide to any Participating Generator, upon its request, copies of any operational assessments, studies or reports prepared by or for the ISO (unless such assessments studies or reports are subject to confidentiality rights or any rule of law that prohibits disclosure) concerning the operations of such Participating Generator's

EXHIBIT 4

ISO Grid Coordinated Planning Process

Introduction - This document describes the process that will be used to plan future changes and additions to the ISO Grid. An overview of the process is shown in Chart 1. The ISO Grid Coordinated Planning Process is extremely flexible in that projects can be generated from a variety of sources including the Transmission Owners, the ISO, or any entity who participates in the energy marketplace through the buying, selling, transmission, or distribution of energy or ancillary services into, out of, or through the ISO Controlled Grid. Having all these interests participate in the planning process is expected to facilitate the development of projects that will result in an ISO Grid that best meets the needs of all its users and maximizes the potential benefits to the State of California. The goal is to meet the reliability needs of the state at the minimum cost to the consumer. The various projects that will be developed through this process will fill a number of needs including the following:

- Interconnecting generation or load
- Protecting or enhancing system reliability
- Improving system efficiency
- Enhancing operating flexibility
- Reducing or eliminating congestion
- Minimizing the need for must-run contracts

The following paragraphs describe the main elements that make up the ISO Grid Coordinated Planning Process:

Annual Transmission Plans - The overall ISO planning process relies heavily on the Participating Transmission Owners (PTOs) which will be filing annual transmission plans primarily just for the portions of the grid that they own. These annual plans are to be coordinated with neighboring systems and are to describe the proposed facility additions over a minimum five year planning horizon. Plans will identify system concerns and evaluate the technical merits of various potential transmission, generation, and operating solutions. In conducting their analysis, the PTOs are to address the needs identified by the various market participants. The ISO will be involved in the PTO annual planning process (see Chart 3). The various power flow and stability base cases developed for these annual plans will be available to the ISO and other market participants so that integrated review and independent studies can be accommodated.

ISO Grid Interconnection - A separate process is specified for facilitating interconnection to the ISO Grid. This interconnection process is primarily between the applicant and the PTO and is shown in Chart 2.

Project Flow Through WICTTP Process - Once projects are identified, they will go through the same Western Interconnection Coordinated Transmission Planning Process (WICTTP) that is in place today. Chart 4 shows the flow of projects through these processes. To the maximum extent possible, the ISO planning process utilizes the WICTTP to streamline the transmission planning process and avoid redundancy. An additional advantage of utilizing the WICTTP is that all of the transmission owners in California follow these processes whether or not they are a PTO.

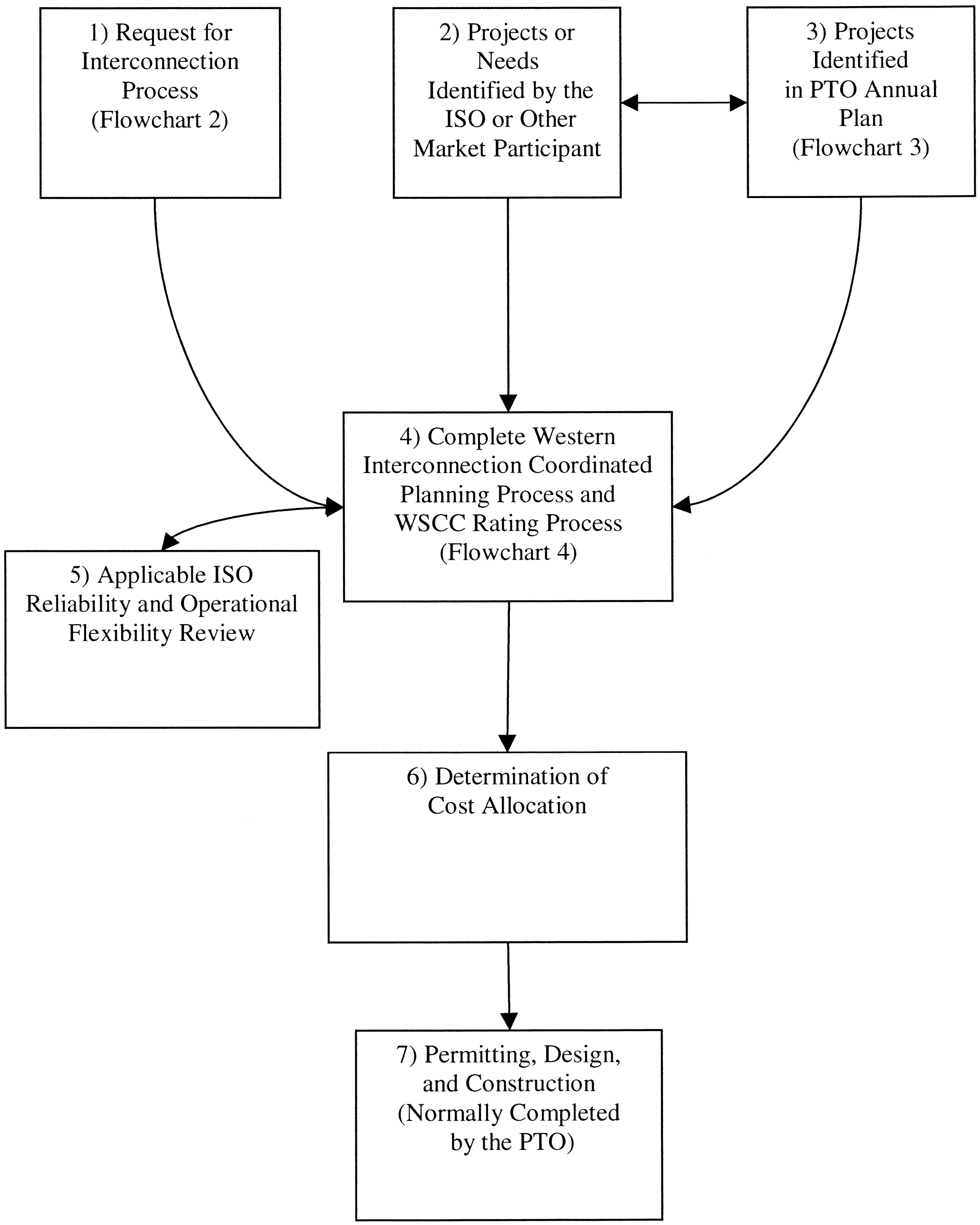
ISO Review Process - In addition, all ISO Grid projects will need to go through an ISO review process. This review is focused on ensuring that projects connected to the ISO grid will meet the ISO Grid planning criteria. For many projects, the assessment of whether they meet the grid planning criteria will have already been made as part of the WICTPP. In addition, concurrently with the WICTTP, the ISO will conduct an operational review to ensure that the project meets the ISO's needs for operational flexibility and meets the ISO's requirements for proper integration with the ISO Grid. Many projects will also need to be evaluated from an economic perspective to determine whether the projects cost should be incorporated into the access fee or split among beneficiaries.

Licensing, Design, and Construction - Finally, at the end of the process, the project is permitted, designed, and constructed. The ISO will track construction to ensure project is in service when needed.

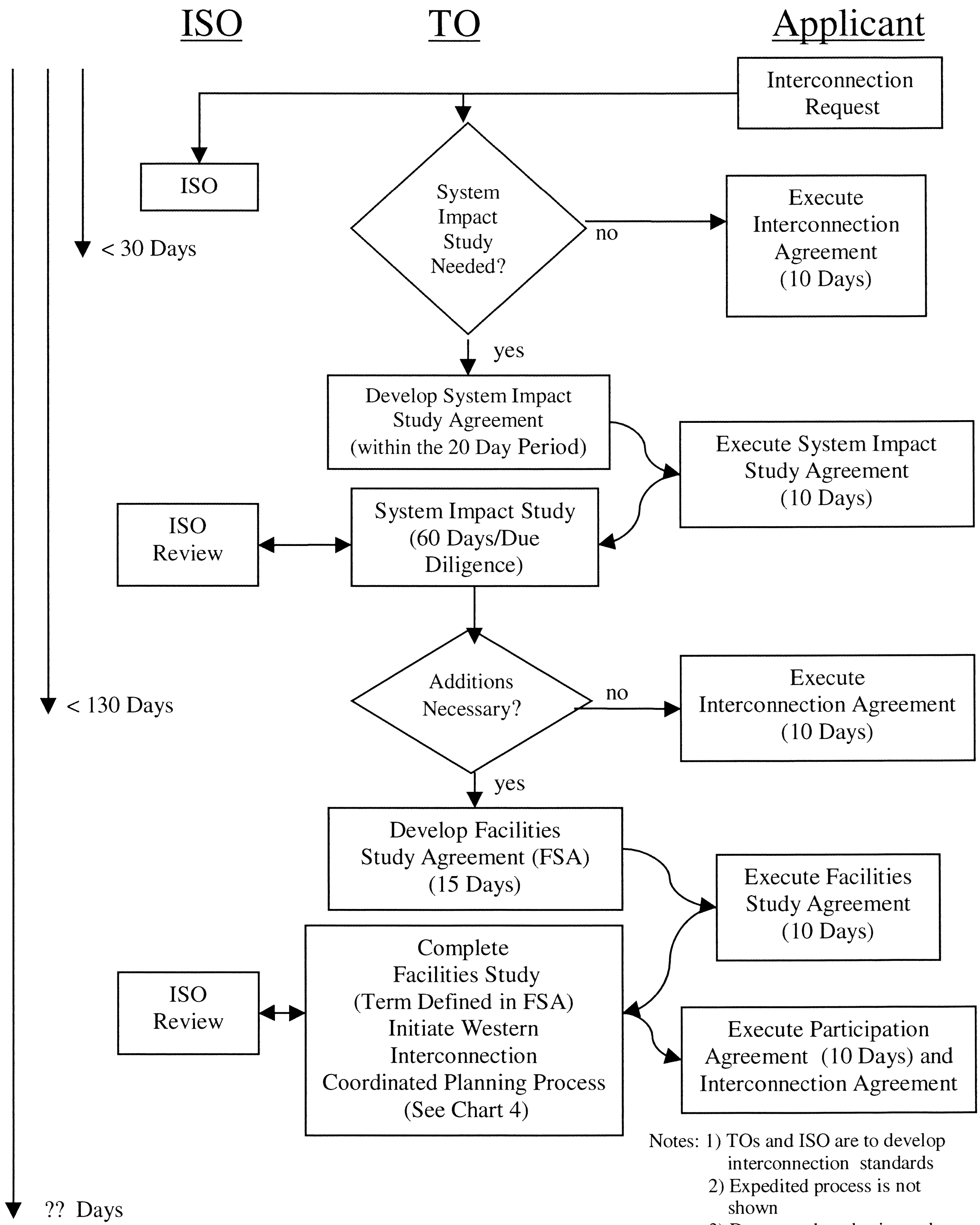
Revision 6
Jeff Miller
January 23, 1998

Flowchart 1

Overview of ISO Grid Coordinated Planning



Flowchart 2
Interconnection Request Study



Notes: 1) TOs and ISO are to develop interconnection standards
2) Expedited process is not shown
3) Days noted are business days
4) See Tariff for details

Explanation of Flowchart 2
ISO Grid Interconnection Process

The process for interconnection to the ISO Grid is described, in detail, in the ISO Tariff. Specifically, see section 10 of the Transmission Control Agreement and sections 8, 9 and 10 of the appropriate Transmission Owner Tariff for additional information.

Interconnection Standards - One part of this process that is not shown on the chart is the requirement that the PTOs will, in coordination with the ISO, develop technical standards for the design, construction, inspection, and testing of proposed Interconnections. Eventually, the ISO, to the extent possible, will develop statewide interconnection standards that will replace the standards initially developed by the PTOs.

Interconnection Process - To ensure that all interconnection requests are processed in a non-discriminatory manner, the PTO shall develop, periodically review, and revise procedures for coordinating interconnection requests. Such procedures will specify the timing for processing individual interconnection requests of differing complexity and the sequencing of coordinating activities with the ISO. In addition, the PTO shall coordinate the operational aspects of such Interconnection with the ISO.

System Impact Study Agreement - Defines the scope, content, assumptions and terms of reference for the study, the estimated time required to complete it, and such other provisions as the parties may reasonably require.

System Impact Study - Upon receipt of an executed System Impact Study Agreement, the PTO will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study shall identify any system constraints, which cannot be reasonably accommodated through ISO Congestion Management, such that transmission expansions or upgrades would be required to provide the requested Interconnection.

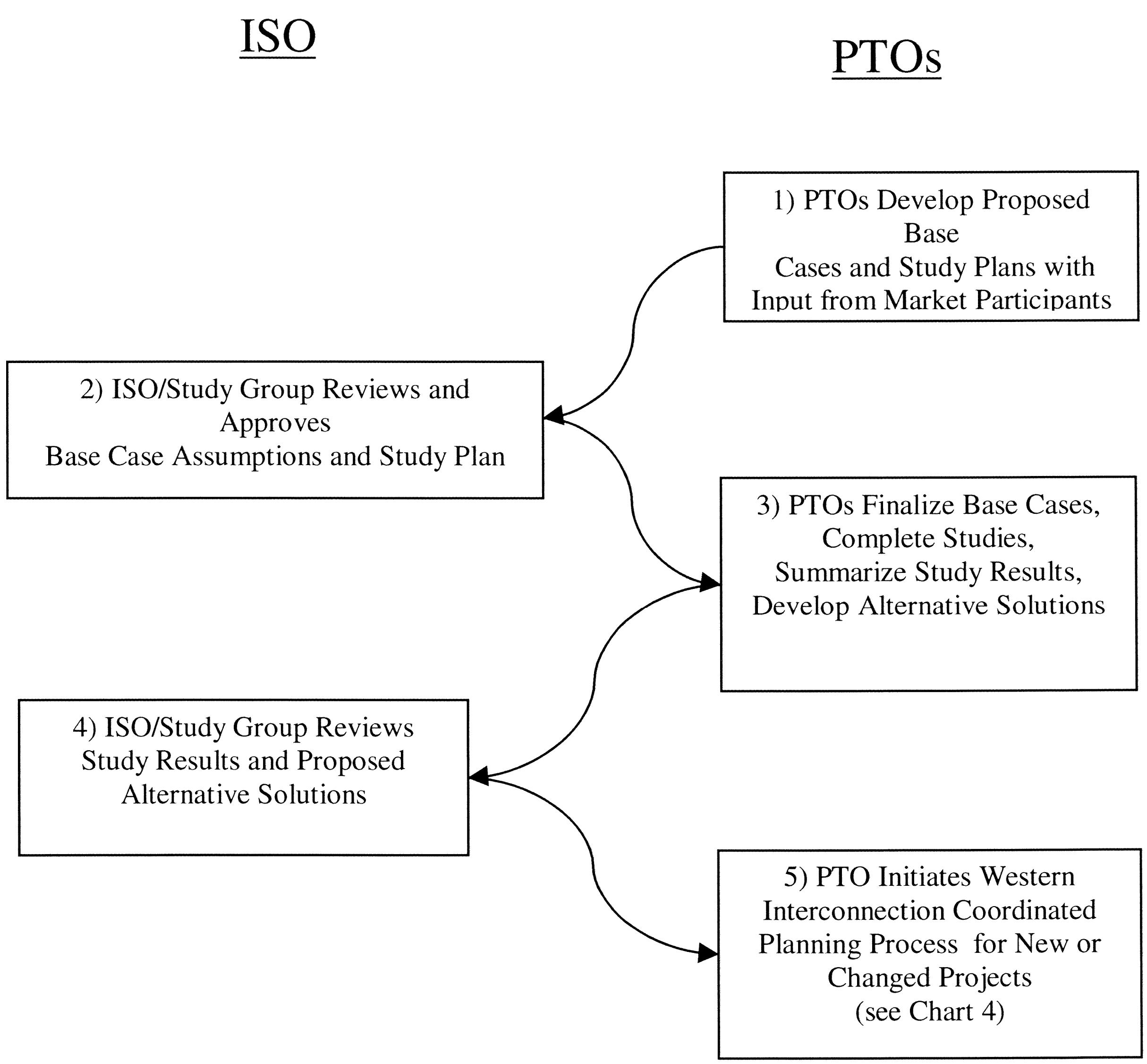
Facilities Study Agreement - Defines the scope, content, assumptions and terms of reference for such study, the estimated time required to complete it, and other provisions as the parties may reasonably require.

Facilities Study - Study necessary to assess the impact of the Interconnection on the ISO Grid and identify the facilities and any necessary reinforcements of the ISO Grid, including any alternative reinforcement options identified by the party requesting the interconnection, that are required for the interconnection. The WICTTP could start at this point in the process or earlier in the process.

Expedited Procedures for New Facilities - In lieu of the procedures shown on Chart 2, the applicant has the option to expedite the process through the expedited procedure described in Section 10.8 of the standard version of the Transmission Owner Tariff.

Flowchart 3

PTO Annual Coordinated System Assessment Process



Explanation of Flowchart 3
The Participating Transmission Owner Annual System Assessment Process

Steps 1 and 2: Develop Base Cases and Study Plans – As part of the development of the annual PTO transmission plans, base cases and study plans will need to be developed. The ISO and other Market Participants need to be involved in the development of these items. The study plan is to be used by the PTOs in completing their annual transmission plans. In preparing the study plan, the PTOs should include the needs identified by the various market participants and describe how those needs are being incorporated into the study process. The base cases should be posted on the ISO Web site so that all market Participants will be able to access them. The PTOs would use these cases as the basis for completing the annual transmission plans and interconnection studies. The ISO and other market participants would use the cases to conduct independent assessments, to evaluate alternatives for eliminating must-run requirements, and to evaluate alternatives for eliminating operating problems identified by the ISO.

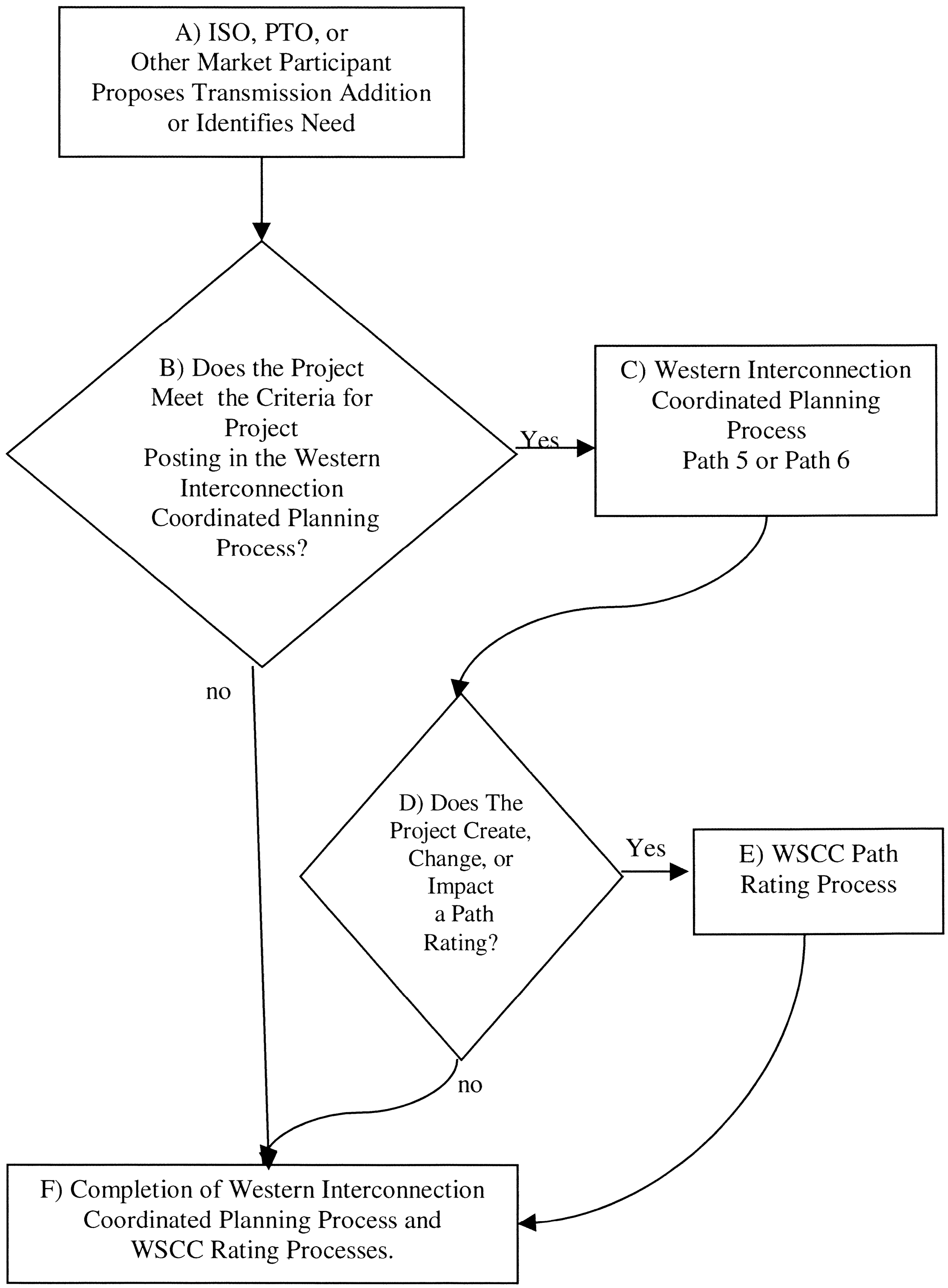
Steps 3 and 4: Conduct System Assessment and Develop Alternative Projects – The PTOs conduct studies to determine where the system cannot meet the reliability criteria during the minimum five year planning horizon and develop alternative projects to correct criteria violations or propose adoption of a waiver. The initial Reliability Criteria to be used in assessing the ISO Grid will be the NERC Planning Standards as adopted by the NERC Board of Trustees on September 16, 1997 (as interpreted by the ISO Grid Planning Criteria Subcommittee) and the WSCC Reliability Criteria for Transmission System Planning. In addition, any portions of the existing utilities' criteria which are more stringent than the NERC Planning Standards would also apply at least for 1998, during which time the ISO will be developing a single ISO Grid planning criteria. Once the transmission owners have assessed whether their system can comply with the reliability criteria, they will note criteria violations and develop alternative solutions to correct those violations. The ISO will review this information and may suggest additional alternatives (transmission, generation, conservation, or operational changes) that the PTO should consider.

Step 5: Western Interconnection Coordinated Transmission Planning Process – These processes are described in Chart 4.

Coordination between PTO and Market Participants – Developing a transmission system that will meet the diverse needs of the state of California requires that all market participants have an opportunity to have input into the transmission planning process. To facilitate this input, each PTO will freely distribute information to the various market participants and provide a forum where the various market participants can meet with the PTOs and other market participants to share ideas and build consensus. At a minimum, each PTO is expected to make base cases, study plans and reports available to all interested market participants in accordance with the attached schedule (not included in the electronic version). The schedule may be adjusted by the Study Group but should not exceed one year. In addition, each PTO is expected to, at a minimum, form a study group of interested market participants and hold meetings at key points in the study process (base case approval, study plan approval, and report completion).

Flowchart 4

Project Flow Through Western Interconnection Coordinated Transmission Planning Process and WSCC Rating Process



Explanation of Flowchart 4

Project Flow Through Western Interconnection Coordinated Transmission Planning Process and WSCC Rating Process

Steps A through C: Western Interconnection Coordinated Transmission Planning Process - The ISO will be a Regional Transmission Group (RTG) and Western Systems Coordinating Council (WSCC) member and will follow these processes for regional planning. These processes will provide the ISO and other interested parties the opportunity to be involved in the early planning stages of transmission projects. One advantage of using these processes is that all California transmission owners follow them whether or not they are an ISO member. New projects (and their alternatives) that have been identified by the PTO, the ISO, or other Market Participants will be posted in the Western Interconnection Coordinated Transmission Planning Process (WICTTP). This process is normally focused on projects that are 100 kV or above. However, the ISO Grid Planning Process will use the WICTPP even if the projects are at a voltage level below 100 kV. Small projects generally receive little interest in these processes and therefore, the process consists of little more than notification that a project is planned. For the more significant additions, these processes can require a significant amount of interaction with other interested parties via the formation of study groups. By having the ISO utilize the WICTTP, the ISO will have the opportunity to review and have input into the development of the ISO Grid. For projects where there is not additional interest other than the PTO and ISO (Path 5 of the WICTTP), the PTO completes analysis of the alternatives and finalizes the project plans with appropriate coordination from the ISO. For projects where there is interest from entities other than the PTO or ISO, a study group would be formed (Path 6 of the WICTTP). The ISO would participate as a member on the study groups for projects that are proposed to become part of the ISO Grid and projects that may have a significant impact on the ISO Grid. The ISO could also sponsor, but not own, projects and would then need to take those projects through the WICTTP. A flow chart of the WICTTP is provided as Attachment A.

Steps D and E: WSCC Rating Process – If a project will be changing or effecting an existing path rating, or creating a new path rating, it will need to go through the WSCC three-phase rating process. The ISO would need to participate in WSCC Review Groups for projects that are either part of the ISO Grid or that could significantly impact the ISO Grid. The flow chart for the Project Rating Procedures used by WSCC is provided as Attachment B. For many projects, the WSCC Rating Process will also serve as the reliability criteria review process normally completed in Step 5 of the ISO Grid Coordinated Planning Process.

EXHIBIT 5

--- Revised Draft 8/4/98 ---

ISO Grid Project Review Information Requirements

This is a generic list of items that may be necessary to fully evaluate a transmission project. All the items need may not need to be responded to for all projects. Engineering judgement should be used to determine how much information should be provided to support a specific project.

I. Description of Proposed Project

1. Provide a description of the proposed project including the approximate miles of line, supporting structure type, substation bus arrangements, etc.
2. ***Provide high-level substation bus arrangement one-lines for substations where changes would occur.***
3. ***Provide maps showing the general routing of new or upgraded transmission lines.***
4. ***Provide maps showing the general geographic location of new substations.***
5. If the project is a phase or part of a larger project, describe the overall project.
6. Provide conceptual locations of new lines and/or stations.
7. If operating actions are proposed to address criteria violations, they should be clearly noted (i.e., load dropping, transfer trip schemes, etc.).
8. Document model data for project (e.g., line impedance's, ratings, shunt capacitor sizes)
9. Discuss special metering or protection requirements
10. Discuss line separation and other common mode exposure items

II. Detailed Cost Estimates

1. Specify major new equipment and cost (i.e., 6 230 kV circuit breakers at $100,000 each).
2. Specify land costs
3. Describe the reason for any unusual variations from typical costs.

III. Project Schedule

1. Environmental and permitting processes
2. Design
3. Construction

IV. Key Issues

1. Land use restrictions
2. Environmental concerns
3. Other

V. Background

1. Identify the problem to be solved – Justification of project need
2. Provide area load projection and load growth trends
3. Document the year when project is required
4. Discuss project status as it pertains to the Western Interconnection Coordinated Transmission Planning Process
5. Provide rationale for selecting the preferred project

VI. Base Case Assumptions (This section should only be included if the base case substantially differs from the base cases developed as part of the annual assessment otherwise, just reference the source case.)

1. Document the background of case (i.e., developed from the WSCC 2003 Heavy Summer and used in the 1998 PG&E annual system assessment)

2. List all other projects included in case that may impact study results.
3. Document load modeling assumptions (i.e., 2003 summer peak with a 1 in 10 likelihood of occurring, constant MVA, power factor)
4. Pre and post-project cases, draw files (if available), and switch files should be made available to the ISO if requested.
5. Describe adherence to operating nomograms and other system requirements (SCIT, AC/DC Nomogram, etc.)
6. Generation assumptions (i.e., dispatch, pump mode, Northern CA hydro)

VII. Study Criteria

1. If any criteria other than the WSCC criteria and the NERC Planning Standards were used, they should be documented.
2. Clearly note any deviations from the WSCC criteria or NERC Planning Standards.

VIII. Study Assumptions

1. Provide a list of key assumptions used in the analysis
2. Document programs used (e.g., GE, PSAPAC, GE-MAPS) (This should be limited to any specialized analytic tools and not the vendor of the standard power systems analysis tools. This will only change very rarely.)
3. Provide discussion of the analytic methods and important assumptions contained therein (i.e., Blocked governors, locked TCULs, etc.).

IX. Documentation of Studies Conducted

1. Perform the necessary power flow, post-transient load flow and stability analyses to verify that WSCC, NERC, and/or other study criteria violation identified in I.1 has been satisfied.
2. Provide table(s) summarizing the outages considered and the effect on facilities in the area of interest
3. ***Provide plots and/or tables showing contingency cases that resulted in criteria violations before or after the addition of the project or its competitive alternatives.***
4. List all sensitivity cases studied and provide plots or tables showing the results from key cases
5. Provide stability plots if stability studies were performed
6. Provide QV and PV plots if these studies were performed
7. Provide short circuit study results if these studies were performed

X. Project Alternatives

1. List alternatives considered including non-transmission alternatives.
2. If alternatives were dismissed, explain why

EXHIBIT 6

ISO Reliability-Must-Run Criteria

Power Flow Assessment:

Contingencies	Criteria: Thermal [3]	Criteria: Voltage [4]
Generating unit [1]	A/R	A/R
Transmission line [1]	A/R	A/R
Transformer [1]	A/R [5]	A/R [5]
Overlapping [2]	A/R	A/R

1 All single contingency outages (i.e. generating unit, transmission line or transformer) will be simulated on participating transmission owners' local area systems.

2 Key generating unit out, system readjusted, followed by a line outage. This over-lapping outage is considered a single contingency within the ISO Grid Planning Criteria. Therefore, load dropping for an overlapping G-1, N-1 scenario is not permitted.

3 Applicable Rating – Based on ISO Transmission Register or facility upgrade plans.

4 Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

5 Based on judgement of ISO and facility owner, a thermal or voltage criterion violation resulting from a transformer outage may not be cause for RMR solution if the violation is considered marginal (e.g. acceptable loss of life or low voltage), otherwise (e.g. unacceptable loss of life or voltage collapse) a RMR solution would be indicated.

Post Transient Load Flow Assessment:

Contingencies	Reactive Margin Criteria [2]
Selected [1]	A/R

1 If power flow results indicate significant low voltages for a given power flow contingency, simulate that outage using the post transient load flow program. The post-transient assessment will develop appropriate Q/V and/or P/V curves.

2 Applicable Rating – positive margin based on 105% of 1 in 2 year load forecast.

Stability Assessment:

Contingencies	Stability Criteria [2]
Selected [1]	A/R

1 If power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency, simulate that outage using the dynamic stability program.

2 Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

EXHIBIT 7

California ISO Approach on the Modeling of New Generation in Power flow Cases

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 ISO 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.

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 Operating 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) 5-year Planning Cases: In these cases, only generation that is under construction (Level 1) should be modeled in the initial power flow case

3) 10-year Planning Cases: In these cases, only generation that is under construction or has received regulatory approval (Levels 1 and 2) 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 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 above modeling assumptions 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. For example, the study group may decide to include a plant that has received regulatory approval but not initiated construction in a five-year planning case based on additional information that may be available that indicates the plant is very likely to be in-service. 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 does not change the queuing process for generators or the current approach used by the PTO's for conducting generator connection studies.