DeShazo, Gary

From: DeShazo, Gary

Sent: Wednesday, September 20, 2006 8:36 PM

To: Mara, Sue; Amirali, Ali; Chifong Thomas (E-mail); Tang, Bob; Tarplee, Gary; Caroline Winn (E-mail); Jaske, Mike; Flynn, Thomas R.; Braun, Tony; Waples, Scott; DeShazo, Gary

Cc: Doughty, Thomas; Dukes, Dana

Subject: CAISO LCR Study Advisory Group

Sue Mara – RTO Advisors
Ali Amirali – LS Power
Chifong Thomas – PG&E
Bob Tang – City of Azusa
Gary Tarplee – SCE (final selection pending)
Carolyn Winn – SDG&E (final selection pending)
Mike Jaske – CEC (final selection pending)
Tom Flynn – CPUC (final selection pending)
Tony Braun – Northern CAISO Municipal (final selection pending)
WECC Reliability Subcommittee Representative (final selection pending)
Gary DeShazo - CAISO (LSAG Chair)

To All:

On behalf of the California ISO, I am pleased to welcome you as a member of the 2008 LCR Study Advisory Group ("LSAG"). Over the coming couple of months, we will collaborate on a review of the assumptions and criteria for this important study. I want to thank you in advance for your investment of time and thought.

As you know, over the last 18 months, the CAISO has been working with stakeholders to determine the locational capacity requirements across the California ISO Controlled Grid in a manner that is consistent with the California Public Utility Commission's ("CPUC") implementation of Resource Adequacy. Earlier this year the CPUC adopted the CAISO's LCR results for 2007. At the same time, the CPUC indicated its desire for the CAISO to continue working with stakeholders towards preparing for the 2008 analysis which will need to begin in January 2007 in order to meet the CPUC's resource adequacy milestones. Commensurate with the CPUC's desire to look forward to 2008, the CAISO is forming the LSAG, a small group of subject matter experts representing a cross-section of stakeholder interests, to take an indepth look at the CAISO's 2007 LCR study assumptions, processes, and criteria and make recommendations for assumptions, processces, and criteria to be used for the 2008 analysis.

In preparation for our inaugural meeting, I hope you will take a moment to review the attached draft charter for the group. It is our hope that the charter will help instill a common understanding of our group's mission and deliverables, which must be completed by the end of November. In consideration of the 2006 holiday season, completing our work in this timeframe should provide ample time for CAISO Staff to initiate the 2008 work in a timely manner.

The details for our first meeting are as follows:

September 28, 2006
Location: California ISO, Building 110
Natomas Conference Room
151 Blue Ravine Road
Folsom, CA 95630
Security considerations: Security badges can be picked up at building 101 which is where the CAISO Board Room is located.

Please RSVP your attendance at this meeting by sending an email to Dana Dukes at ddukes@caiso.com or by calling Dana at (916) 608-5715.

Call me at any time with questions. We're looking forward to a robust and constructive discussion with you.

Gary DeShazo
Director, Regional Transmission North
(916) 608-5880

Draft Agenda
LCR Study Advisory Group (LSAG) Meeting
September 28, 2006
10am – 4pm
Natomas Room
California ISO

I. Introductions - All

II. Arrangements & Support - DeShazo

III. Review Agenda - All

IV. LSAG Charter – DeShazo

- **A. Purpose of the Group**
  - **1. Advise**
  - **2. Aid**
- **B. Representation and Expectations of Participants**
- **C. Objectives**
  - **1. Review and validate 2007 LCR study**
  - **2. Consensus on 2008 LCR Study Assumptions, processes, & criteria**
  - **3. Document LSAG Recommendations**
- **D. Scope of Activities**
- **E. Group Comments - All**

V. 2007 LCR Study Review - Micsa

- **A. Base Cases**
- **B. Load Pockets**
- **C. Category B Contingencies**
- **D. Category C Contingencies**
- **E. Application of NERC/WECC Criteria**

VI. Identify Action Items – Dukes

VII. Establish Meeting Schedule and Locations – All

VIII. Other Items - All

IX. Adjourn

Brief Summary of Technical Issues from Comments Submitted to CPUC On CAISO 2007 LCR Study/Report

1) AReM
   a) Probability of events
2) SCE
   a) Allowance for operating procedures
   b) South of Lugo, Category D type disturbance
3) CCSF
   a) Load Pockets
4) Constellation Power
   a) Clarify qualifying capacity
   b) How are operating procedures accommodated in study
5) NCPA
   a) Did not allow load shedding for N-2
   b) Probability of events
   c) Did not adjust system after first contingency
6) IEP
   a) Clarity on load pockets
7) PG&E
   a) Stable and consistent approaches to study
   b) Ambiguity in NERC/WECC standard; specifically, allowance of load shedding
   c) Sub-area approach may cause over procurement
   d) Sierra – reliability or congestion issue
   e) Use of 5% threshold cost effective
8) DRA
   a) Clarity on N-1-1 versus N-2
9) Energy Producers & Users Coalition
   a) Probability of events

California ISO
Your Link to Power

CAISO LCR Study Advisory Group

Sign-In Sheet
Thursday, September 28, 2006

Name	Signature	Company	Contact Number
Dave Timson	[illegible]	ESC	608-1134
CHIFONG THOMAS	Chifong Thomas	PG&E	415-973-7646
Catalin Micsa	Catalin [illegible]	Cal-ISO	(916)-608-5704
Gary DeShazo	Gary DeShazo	CAISO	916 608 5880
Garry Chinn	Garry Chinn	SCE	626 302 8365
Les Pereira	[illegible]	NCPA	916 781-4218
BOB ELLIOTT	[illegible]	CPUC	415 703 2527
Randall Hunt	Randall S. H[illegible]	Navigant	916-631-3276
Bob Tang	[illegible]	Six Cities	626-812-5214
Sue Mara	Sue Mara	RTOAdvisors (ESPs)	415 902-4108
Jan Strack	- on phone -	SDG&E	
MARK HESTERS	[illegible]	CEC	916 654-5049
Ali Amirali	A. Amirali	Representing IEP	(408) 204-7630
Dana Dukes	[illegible]	CAISO	916 608 5715

Charter - CAISO LCR Study Advisory Group (LSAG)

September 5, 2006

Introduction

In preparation for the 2008 Local Capacity Requirements ("LCR") Study, and the recognized need for transparency and industry involvement, the CAISO shall form an LCR Study Advisory Group ("LSAG"). The LSAG shall evaluate, assist in any recommended refinement of, and comment on the study assumptions, processes and criteria to be used by the CAISO in the 2008 LCR Study. This effort must be completed by November 2006 in order to complete the 2008 LCR Study in a timeframe consistent with existing regulatory parameters.

Mission and Purpose

The LSAG shall be an ad hoc group of experts, meeting the criteria set forth below, representing identified segments of California's electricity marketplace, formed and administered by the CAISO. The LSAG will:

I. Advise the CAISO Transmission Planning organization on the , assumptions, and study criteria for the 2008 LCR Study.
II. Aid the CAISO in developing the study plan and support the development of communications regarding the 2008 LCR Study to other market participants.

Anticipated Scope of Activities

Within the LSAG time horizon and the 2008 LCR Study deadlines, as noted above, the LSAG will:

I. Review and provide input on the CAISO's 2008 LCR Study plans, documents and materials, including suggested refinements, prior to publication to the broader stakeholder audience.
II. Propose methods to advance collaboration between CAISO and market participants on the LCR Study.
III. Discuss issues related to the LCR study, which are brought by CAISO and LSAG participants, and formulate options for resolution.
IV. Produce, if necessary or desired, comments on the final CAISO LCR Study assumptions and criteria.

Participant Representation

LSAG participants shall be required to possess specific training and/or experience in at least two of the following areas:

1. Transmission planning
2. Performing powerflow modeling
3. Grid operations

4. WECC/NERC reliability criteria

Such individuals must provide to the CAISO a resume/curriculum vitae verifying satisfaction of the foregoing eligibility standards.

The CAISO will make a reasonable effort to select eligible individuals from, or representing, the following regulatory entities, market participants or industry segments:

1. California Public Utilities Commission
2. California Energy Commission
3. Western Electricity Coordinating Council
4. Pacific Gas and Electric Company
5. Southern California Edison Company
6. San Diego Gas & Electric Company
7. CAISO Control Area municipal or other local public utilities – North and South
8. Large end-use customers Small end-use customers
9. Electric Service Providers/Community Choice Aggregators
10. Generators

The CAISO will, therefore, select among identified and qualified individuals to form a broad-based advisory group consisting of at least eleven (11) participants. The CAISO's selection shall be binding.

Once selected, participation is name-specific and is not assignable or delegable. All efforts will be made to coordinate schedules to maximize participation and the opportunity to participate by telephone will be provided for all LSAG meetings as noted below.

Duration and Term

LSAG is expected to remain active through November 2006, or at such time that the study assumptions are complete for the 2008 LCR Study, whichever comes first.

Group Operations / logistics

LSAG will meet between September and November 2006. Meetings will be in face-to-face or conference call formats.

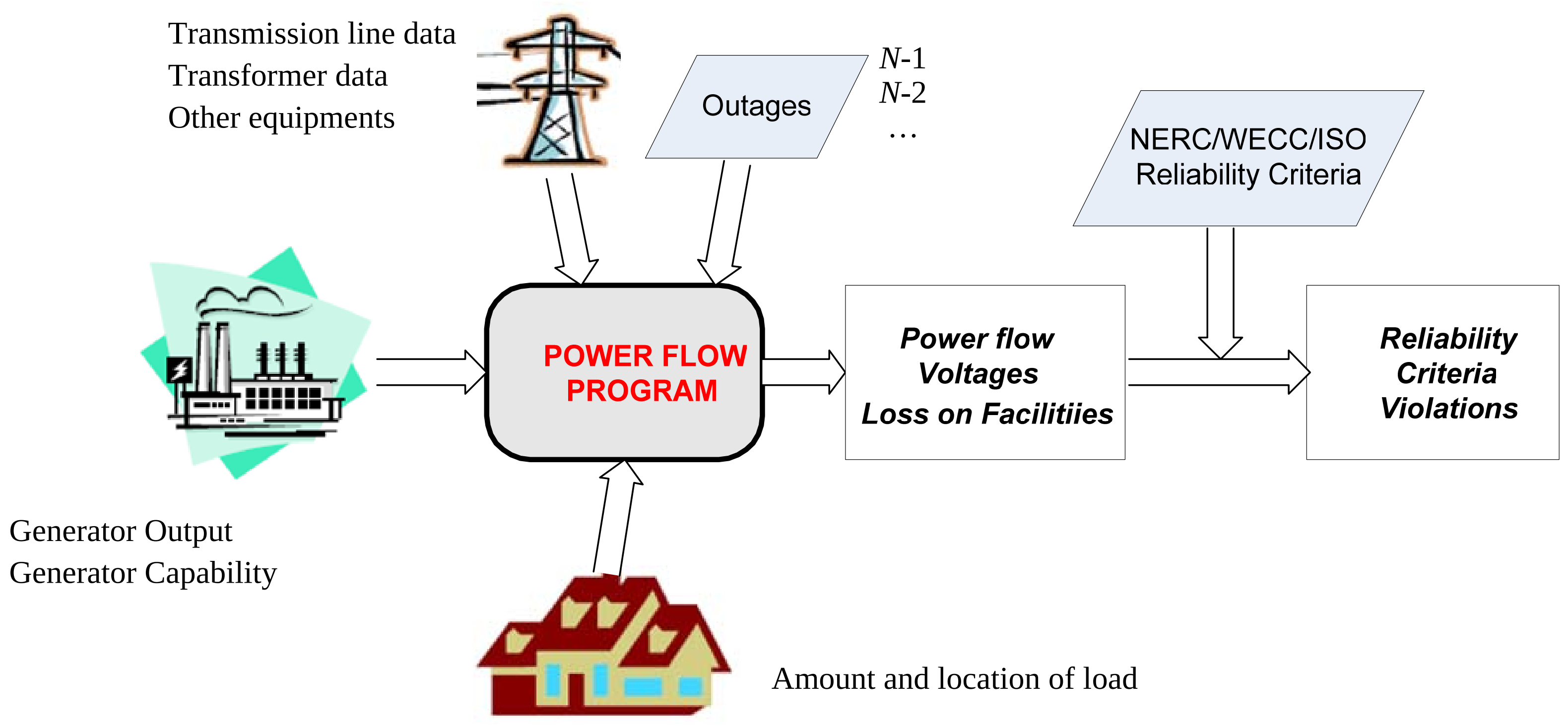
I. CAISO will develop and publish a schedule of LSAG meetings from September through November 2006.
II. CAISO will develop and publish LSAG meeting agendas and supporting documents approximately one week prior to each meeting to the extent possible.
III. CAISO will provide telephone dial-in capability for all LSAG meetings.
IV. In addition to reviewing CAISO-initiated issues, each meeting will include time for LSAG members to introduce issues for discussion.
V. CAISO staff will chair and participate in the LSAG meetings.

VI. CAISO will track issues and action items identified in the LSAG meetings, and will post any materials produced in response to such issues or action items to its web site.

Reliability

- Power Flow Studies

Simulation of snapshot steady-state system conditions. Compared results against reliability criteria to determine criteria violations.



California ISO

2007
LOCAL CAPACITY TECHNICAL ANALYSIS

REPORT
AND STUDY RESULTS

Corrected Version July 18, 2006

Local Capacity Technical Analysis
Overview and Study Results

I. Executive Summary

At the February 3, 2006 prehearing conference in Docket R.05-12-013 (*Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program*), the California Independent System Operator Corporation ("CAISO") advised the California Public Utilities Commission ("CPUC") that the Local Capacity Requirement ("LCR") results of its 2007 local capacity technical analysis could be made available within eight weeks after the development of the input assumptions for the study. Following a meet and confer process, Administrative Law Judge Wetzell adopted proposed study assumptions. These assumptions have been incorporated into this "Local Capacity Technical Analysis Study ("2007 LCR Study"), as discussed below. The CAISO has now completed its analysis and therefore provides this 2007 LCR Study to describe the final LCR results and the methodology and criteria used to obtain those results.

This Report provides a description of the 2007 LCR Study objectives, inputs, methodologies and assumptions, and the important policy considerations that are presented by the study results. Specifically, as requested by the Stakeholders and approved by the CPUC, the CAISO has conducted the study to produce local area capacity requirements necessary to achieve three levels of service reliability. These levels of service reliability, which are driven by the transmission grid operating standards to which the CAISO must comply, are set forth on the following table[1]:

[1] This comparison table is explained in detail at Section IV. below. The reader should be aware that the deficiencies identified for certain local areas are driven by capacity requirements in sub-area load pockets discussed at IV.B.

Local Requirements Comparison

	Qualifying Capacity			2007 LCR Requirement Based on Category B Option 1			2007 LCR Requirement Based on Category C with operating procedure Option 2			2006 Total LCR Req.
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**(MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**	162
North Coast / North Bay	158	861	1019	582**	0	**582****	582**	0	**582****	658
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**	1770*
Stockton	314	257	571	432	0	**432**	536	53	**589**	440*
Greater Bay	1314	5231	6545	4771	0	**4771**	4771**	0	**4771****	6009
Greater Fresno	575	2337	2912	2115	0	**2115**	2151	68	**2219**	2837 *
Kern	978	31	1009	554	0	**554**	769	17	**786**	797*
LA Basin	3510	7012	10522	8843	0	**8843**	8843	0	**8843**	8127
San Diego	191	2741	2932	2781	0	**2781**	2781	0	**2781**	2620
Total	**8185**	**19379**	**27564**	**22113**	**205**	**22318**	**22468**	**466**	**22934**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR
** The North Coast/North Bay and Greater Bay Area requirements would have been higher by 80 and 570 MW respectively, however two new operating procedures have been received, validated and implemented by PG&E and the CAISO.

The term "Qualifying Capacity" used in this report represents the "Gross Qualifying Capacity" (as of 1/12/2006) and it may be slightly higher, for certain generators, then the "Net Qualifying Capacity" as presented in the official list stored at:

http://www.caiso.com/1796/179694f65b9f0.xls

The difference between the terms "Qualifying Capacity" and "Net Qualifying Capacity" is that certain units have associated plant load and thus, the "Net Qualifying Capacity" represents the output from the unit after the plant load has been subtracted. However, the LCR Study incorporates the plant load from these units into the "total load" calculation.

The first column, "Qualifying Capacity", reflects two sets of generation. The first set is comprised of generation that would normally be expected to be on-line such as Municipal generation and Regulatory Must-take generation (State, Federal, QFs and nuclear units). The second set is "market" generation. The second column, “2007 LCR Requirement Based on Category B” identifies the local capacity requirements, and deficiencies that must be addressed, in order to achieve a service reliability level based on Performance Criteria- Category B (Option 1, discussed in Section II.C of this Report). The third column, “2007 LCR Requirement Based on Category C with Operating Procedure”, sets forth the local capacity requirements, and deficiencies that must be addressed, necessary to attain a service reliability level based on Performance Criteria-Category C with operational solutions (Option 2).

The highest service reliability level, based on Performance Criteria-Category C without non-generational solutions to address operating deficiencies (Option 3), can be determined from the table by adding 80 MW to the local capacity requirements for the North Coast/North Bay area (thus raising total 2007 LCR requirements by 80 MW). This exercise removes the new operating procedure provided by PG&E from the analysis in compliance with the Category C reliability standard that relies solely on generation to address identified capacity deficiencies.

As shown on the table above, the study results have important public policy implications. These study results indicate 3 levels of capacity that are necessary to have sufficient capacity in support of 3 levels of service reliability. The reader should appreciate that the differences in levels of capacity have direct implications to the costs and expected levels of reliability that are achieved for customers located within the local areas. Thus, option 1 (performance level B) has a lower level of capacity required and will therefore have an expected lower level of reliability because less capacity is available to the CAISO. Similarly, the operational solutions underlying option 2 (performance level C) provide for less procurement of capacity than option 3 by placing load in the mix of solutions that the CAISO will use to respond to contingencies. This approach may be appropriate where all outages are expected to have short-term affects on the transmission system. Yet, long duration outages would potentially subject load to extended outages. Option 3 also NERC performance level C, results provide the quantity of capacity that would give the CAISO a full set of capacity to respond to contingencies. This level effectively reserves the load based operational solutions for major emergencies or contingencies that are not considered in the study criteria and therefore results in an expected higher level of service reliability than the two alternate options.

Public policy decision-makers must choose the appropriate level of service reliability. The information provided in the 2007 LCR Study, including the CAISO's recommendations found at Section II.E. below, can assist with this choice.

II. Overview of The Study: Inputs, Outputs and Options

A. Objectives

Similar to the 2006 Local Capacity Technical Analysis ("2006 LCR Study")[2], the purpose of the2007 LCR Study is to identify specific areas within the CAISO Controlled Grid that have local reliability problems and to determine the generation capacity (MW) that would be required to mitigate these local reliability problems. However, based on input from market participants and at the direction of the CPUC, the 2007 LCR Study identifies different levels of local capacity that correspond to separate performance/reliability criteria related to grid robustness under which the CAISO must plan and operate the grid. This additional information is intended to allow the CPUC to affect the expected level of service reliability that customers of jurisdictional LSEs will receive by dictating the appropriate amount of local capacity that must be procured. In so doing, the CPUC should endeavor to make a decision that seeks to find the appropriate balance between a desired level of service reliability and the cost of installed capacity. The details of the 2007 LCR study, set forth in the following sections, will facilitate the CPUC's ability to make this important decision.

[2] The 2006 LCR Study (Locational Capacity Technical Analysis: Overview of Study Report and Final Results) dated September 23, 2005 was submitted to the CPUC as part of the CAISO's Motion to Augment the Record Regarding Resource Adequacy Phase 2 in R.04-04-003. An Addendum to the 2006 LCR Study was submitted on January 31, 2006. These documents can be found on the CAISO website at: http://www.caiso.com/1788/178883551f690.html and http://www.caiso.com/docs/2004/10/04/2004100410354511659.html

B. Key Study Assumptions

1. Inputs and Methodology

The CPUC directed the CAISO, respondents, and other interested parties to meet and confer with the objective of identifying not more than three alternative sets of input assumptions the CAISO would incorporate into the 2007 LCR Study. The meet and confer session was held on February 17, 2006 and, as noted above, the agreed-upon input scenarios were submitted by the CAISO on February 22, 2006. An errata to the February 22 filing was submitted on March 10, 2006. The following table sets forth a summary of the approved inputs and methodology that have been used in the 2007 LCR Study:

Summary Table of Inputs and Methodology Used in 2007 LCR Study:

Issue:	HOW INCORPORATED INTO THE 2007 LCR STUDY:
<u>Input Assumptions:</u>	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, 2007 and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.
• Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, 2007
• Load Forecast	Uses a 1-in-10 year summer peak load forecast

Methodology:	
• **Maximize Import Capability**	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• **QF/Nuclear/State/Federal Units**	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at historical output values for purposes of the 2007 LCR Study.
• **Maintaining Path Flows**	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in the 2007 LCR Study is the South of Lugo transfer path flowing into the LA Basin.
Performance Criteria:	
• **Performance Level B & C, including incorporation of PTO operational solutions**	The 2007 LCR Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, 2007. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCR Study and the resulting LCR published for this third scenario.
Load Pocket:	
• **Fixed Boundary, including limited reference to published effectiveness factors**	The 2007 LCR Study has been produced based on load pockets defined by a fixed boundary. The CAISO was initially planning to publish the effectiveness factors of the generating resources within the defined load pocket as well as the effectiveness factors of the generating resources residing outside the load pocket that had a relative effectiveness factor of no less than 5% or affect the flow on the limiting equipment by more than 5% of the equipment's applicable rating. . However, after subsequent discussions with the Commission and stakeholders, and given the comments in the CPUC Staff Report regarding the limited usefulness of effectiveness factors, the CAISO plans to only publish effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket. If stakeholders want additional effectiveness factor published, the CAISO will defer to the Commission as to what further effectiveness factor data it would like the CAISO to publish.

Further details regarding the 2007 LCR Study methodology and assumptions are provided in Section III, below.

2. Operating Requirements

As was done in the 2006 LCR Study, this study incorporates specific operating requirements, needed in order to prevent voltage collapse or transient instability for the loss of a single transmission element ("N-1") followed by system readjustment and the loss of two transmission lines (common mode failure)[3]. In addition, the LCR Study addresses contingencies where the system suffers the loss of a single transmission element ("N-1"), the system is readjusted and then the loss of an additional transmission element (N-1-1). As reflected in Table 2, the capacity in columns two (Category B) and three (Category C) are identical in at least four of the local areas. This occurs because the capacity necessary to prevent voltage collapse or transient instability for the loss of a single transmission element (N-1) is the same as that necessary for the N-1-1 scenario.

Consistent with NERC standards, after the second N-1 or immediately after the common mode failure load shedding is allowed as long as all criteria (thermal, voltage, transient, reactive margin) are respected. The CAISO planning criteria generally allows for load shedding for the double contingencies. However, the CAISO has, consistent with its Tariff, conducted planning studies that maintain the level of reliability that existed prior to its formation. This is referred in the CAISO Tariff as "Local Reliability Criteria," which, along with NERC Planning Standards discussed below, form the CAISO's "Applicable Reliability Criteria" The CAISO is under an obligation to implement Local Reliability Criteria, unless modified pursuant to agreement with the relevant Participating Transmission Owner ("PTO"). As such, to the extent a PTO's pre-CAISO standards did not allow for load shedding for common corridor and/or double circuit tower line outages, the CAISO has maintained that practice to assure that the level of reliability that prevailed before the CAISO was formed would be maintained and the CAISO remains in compliance with its obligations.

[3] These failures include a double circuit tower and the loss of two 500kv lines that are located in the same corridor.

C. Grid Reliability and Service Reliability

The 2007 LCR Study is intended to provide the CPUC with the “tools” needed to make the important threshold policy decision as to the desired level of service reliability within the CAISO Control Area, ultimately establishing the appropriate amount of local generation capacity CPUC jurisdictional LSEs must procure. The options produced by the study for consideration by the CPUC are discussed in further detail in this overview section of the report, and also in the technical discussion of the study itself. However, to assist the CPUC in analyzing the study results and the options that are being presented, it is important that the CPUC and other parties understand how the CAISO distinguishes “service reliability” from “grid reliability” and where the respective CAISO/CPUC responsibilities lie. Both service and grid reliability form the basis of the reliability standards consumers within the CAISO Control Area will receive.

1. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the planning standards of the Western Electricity Coordinating Council (“WECC”) that incorporate standards set by the North American Electric Reliability Council (“NERC”) (collectively “NERC Planning Standards”). The NERC Planning Standards primarily apply to the bulk, interconnected electric system in the Western United States and are intended to address the reality that within an integrated network, whatever one control area does can affect the reliability of other control areas. Consistent with the mandatory nature of the NERC Planning Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the NERC Planning Standards.[4] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all “Applicable Reliability Criteria.” Applicable Reliability Criteria consists of the NERC Planning Standards as well as reliability criteria adopted by the CAISO, in consultation with

[4] Pub. Utilities Code § 345

the CAISO's Participating Transmission Owners ("PTOs"), which affect a PTO's individual system.

The NERC Planning Standards define reliability on interconnected bulk electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The NERC Planning Standards are organized by Performance Categories. For instance, one category could require that the grid operator not only ensure grid integrity is maintained under certain adverse system conditions, e.g., security, but also that all customers continue to receive electric supply to meet demand, e.g., adequacy. In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy. Here, it would be up to the regulatory agency of service reliability, i.e. the CPUC, to determine the appropriate level of service reliability under the system conditions defined by the differing levels of NERC planning standards.

Given the foregoing, one of the ambiguities identified in the recent CPUC workshops is the fact that several performance categories make up the NERC Planning Standards and, therefore, Applicable Reliability Criteria. The various parties perceived this as potentially permitting the CAISO to procure generation, in its backstop role, to satisfy all performance categories. Rather, the CAISO believes it is the role of the CPUC to determine the level of service reliability it wishes to establish for the ratepayers. To further addresses this concern, it is important to again describe the Performance Categories, which are critical to understanding how the CPUC and CAISO can work together.

a. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, the 2007 LCR is based on NERC Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. These Performance Levels can be described as follows:

i. Performance Criteria- Category B

Category B describes the system performance that is expected following the loss of a single transmission element, such as a transmission circuit, a generator, or a transformer.

Category B system performance requires that all thermal and voltage limits must be within their "Applicable Rating," which, in this case, are the emergency ratings as generally determined by the PTO or facility owner. Applicable Rating includes a temporal element such that emergency ratings can only be maintained for a certain duration. Under this category, load cannot be shed in order to assure the Applicable Ratings are met and that facilities are returned to normal ratings when either the element that was lost is returned to service or system adjustments are made within the appropriate time limits.

However, the NERC Standards require system operators to "look forward" to make sure they safely prepare for the "next" N-1 following the loss of the "first" N-1 (stay within Applicable Ratings after the "next" N-1). This is commonly referred to as N-1-1. Because it is assumed that some time exists between the "first" and "next" element losses, operating personnel may make any reasonable and feasible adjustments to the system to prepare for the loss of the second element, including, pre-contingency load-shedding, dispatching generation, moving load from one substation to another to reduce equipment loading, dispatching operating personnel to specific station locations to manually adjust load from the substation site, or installing a "Special Protection Scheme" that would remove pre-identified load from service upon the loss of the "next " element.[5]

ii. Performance Criteria- Category C

Category C describes system performance that is expected following the loss of two or more system elements. This loss of two elements is generally expected to happen simultaneously, referred to as N-2. It should be noted that once the "next" element is lost after the first contingency, as discussed above under the Performance Criteria B, N-1-1 scenario, the event is effectively a Category C. As noted above, depending on system design and expected system impacts, the controlled interruption of supply to customers (load shedding), the removal from service of certain generators and curtailment of exports may be utilized to maintain grid "security."

2. Service Reliability

The CAISO is responsible for grid reliability in accordance with the NERC performance criteria described above. However, grid reliability can be maintained at service reliability levels that may be unacceptable to the CPUC and end user customers. The 2007 LCR Study presents the CPUC with relevant information to select a level of service reliability that also fulfills grid reliability. Specifically, the study specifies varying generation capacity levels for each local capacity area based on Performance criteria- Categories B and C, with the inclusion of suitable non-generation solutions raised by the PTOs to address contingency conditions as described under Performance Criteria- Category C.

---

[5] A Special Protection Scheme is typically proposed as an operational solution that does not require additional generation and permits operators to effectively prepare for the next event as well as ensure security should the next event occur. However, these systems have their own risks, which limit the extent to which they could be deployed as a solution for grid reliability augmentation. While they provide the value of protecting against the next event without the need for pre-contingency load shedding, they add points of potential failure to the transmission network. This increases the potential for load interruptions because sometimes these systems will operate when not required and other times they will not operate when needed.

As shown by the study results, where the NERC Planning Standards do not allow for load shedding, grid reliability and service reliability are the same and establish a minimum level of capacity needed to meet the CAISO's statutory obligation.[6] Where it is not possible to develop operating solutions to ensure "controlled" interruption of service, in these cases generation will also be required to meet Applicable Reliability Criteria to avoid the potential of load shedding in anticipation of a contingency. Where feasible operational solutions and/or generation procurement amounts affect the level of service to customers, service reliability is implicated and different levels of service reliability may be possible.

D. The Three Options Presented By The 2007 LCR Study

The 2007 LCR study sets forth different solution "options" with varying ranges of potential service reliability consistent with CAISO's Applicable Reliability Criteria:

1. Option 1- Meet Performance Criteria Category B

Option 1 is a service reliability level that reflects generation capacity that must be available to comply with reliability standards for NERC Category B given that load cannot be removed to meet this performance standard under Applicable Reliability Criteria. However, this capacity amount implicitly relies on load interruption as the **only means** of meeting any Applicable Reliability Criteria that is beyond the loss of a single transmission element (N-1). These situations will likely require substantial load interruptions in order to maintain system continuity and alleviate equipment overloads including load interruptions prior to the actual occurrence of the second contingency.[7]

---

[6] The NERC Planning Standards reflect a "deterministic" analysis that captures the "robustness" of the grid. In many NERC subregions, service reliability is understood as the probability of disconnecting firm load due to a resource deficiency. Control areas in the Western Electricity Coordinating Council, including the CAISO, do not currently have sufficient information to apply a probabilistic reliability analysis to transmission or planning studies. However, the CAISO has consistently recommended that the CPUC move to a loss of load probability approach as a means by which to consider alternative solutions while still planning to a desired level of service reliability.

7 This potential for pre-contingency load shedding also occurs because real time operators must prepare for the loss of a common mode N-2 at all times.

2. Option 2- Meet Performance Criteria Category C and Incorporate Suitable Operational Solutions

Option 2 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity *after* considering all reasonable and feasible operating solutions (involving customer load interruption) developed and approved by the CAISO, in consultation with the PTOs. Under this option, there is no expected load interruption to end-use customers as the CAISO operators prepare for the second contingency. However, the customer load will be interrupted in the event the second contingency occurs.

3. Option 3- Meet Performance Criteria Category C through Pure Procurement

Option 3 is a service reliability level that reflects generation capacity that is needed to readjust the system to prepare for the loss of a second transmission element (N-1-1) using generation capacity only. No load based operational solutions are incorporated into this scenario. Therefore, this results in a "pure capacity" procurement scenario.

E. The CPUC's Responsibilities and The CAISO's Recommendation

The CPUC is responsible for determination of the appropriate level of service reliability to end-use customers within each CAISO-identified local capacity area. The CPUC may meet this responsibility by exercising its jurisdiction over load serving entities to compel procurement of generation or demand resources to meet the option selected. The CPUC may also wish to allow the load serving entity to choose planned or controlled load interruption options.[8] The CPUC should impose appropriate penalties for LSEs that fail to comply with the procurement levels that are necessary to meet its established applicable reliability criteria standard. Finally, in its determination of an acceptable service reliability level, the CPUC should

[8] However, such automatic load shedding schemes or operating procedures implementing manual load shedding options must be acceptable to the CAISO, i.e., the load to be shed is demonstrable, verifiable, and appropriately dispatchable.

explicitly understand the implications associated with contingent events as well as the potential that customers will receive different levels of service reliability based on the service reliability level selected for each local capacity area.

As the grid operator, the CAISO recommends that Option 2 be selected as the service reliability standard. Option 2 identifies a potential service reliability that reflects generation capacity set forth in (2) above, adjusted for any feasible operating solution identified by a PTO prior to the study and approved by the CAISO. On a day-to-day basis the CAISO has traditionally operated the network based on the N-1-1 contingency, with operating solutions developed with the PTOs. Should the CPUC choose Option 2, and to the extent a load shedding solution proposed by a PTO is isolated solely in the service territory of a CPUC load serving entity, the CAISO has indicated the appropriateness of such operating procedure to the CPUC in this study.

III. Assumption Details: How the Study was Conducted

A. System Planning Criteria

The following table provides a comparison of system planning criteria, based on the NERC performance standards, used in the study:

Table 1: Criteria Comparison

Contingency Component(s)	ISO Grid Planning Criteria	Existing RMR Criteria	Locational Capacity Criteria
<u>A – No Contingencies</u>	X	X	X
<u>B – Loss of a single element</u>			
1. Generator (G-1)		X	X[1]
2. Transmission Circuit (L-1)	X	X	X[1]
3. Transformer (T-1)	X	X[2]	X[1,2]
4. Single Pole (dc) Line	X	X	X[1]
5. G-1 system readjusted L-1	X	X	X
<u>C – Loss of two or more elements</u>			
1. Bus Section	X		
2. Breaker (failure or internal fault)	X		
3. L-1 system readjusted G-1	X		X
3. G-1 system readjusted T-1 or T-1 system readjusted G-1	X		X
3. L-1 system readjusted T-1 or T-1 system readjusted L-1	X		X
3. G-1 system readjusted G-1	X		X
3. L-1 system readjusted L-1	X		X
3. T-1 system readjusted T-1	X		
4. Bipolar (dc) Line	X		X
5. Two circuits (Common Mode) L-2	X		X
6. SLG fault (stuck breaker or protection failure) for G-1	X		
7. SLG fault (stuck breaker or protection failure) for L-1	X		
8. SLG fault (stuck breaker or protection failure) for T-1	X		
9. SLG fault (stuck breaker or protection failure) for Bus section	X		
WECC-S3. Two generators (Common Mode) G-2	X[3]		X
<u>D – Extreme event – loss of two or more elements</u>			
Any B1-4 system readjusted (Common Mode) L-2	X[4]		X[3]
All other extreme combinations D1-14.	X[4]		

1 System must be able to readjust to normal limits.

2 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

3 Evaluate for risks and consequence, per NERC standards. No voltage collapse or dynamic instability allowed.

4 Evaluate for risks and consequence, per NERC standards.

A significant number of simulations were run to determine the most critical contingencies within each Local Capacity Area. Using power flow, post-transient load flow, and stability assessment tools, the system performance results of all the contingencies that were studied were measured against the system performance requirements defined by the criteria shown in Table 1. Where the specific system performance requirements were not met, generation was adjusted such that the minimum amount of generation required to meet the criteria was determined in the Local Capacity Area. The following describes how the criteria were tested for the specific type of analysis performed.

1. Power Flow Assessment:

Contingencies	Thermal Criteria[3]	Voltage Criteria[4]
Generating unit [1, 6]	Applicable Rating	Applicable Rating
Transmission line [1, 6]	Applicable Rating	Applicable Rating
Transformer [1, 6]	Applicable Rating[5]	Applicable Rating[5]
(G-1)(L-1) [2, 6]	Applicable Rating	Applicable Rating
Overlapping [6, 7]	Applicable Rating	Applicable Rating

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, L-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 A thermal or voltage criterion violation resulting from a transformer outage may not be cause for a local area reliability requirement if the violation is considered marginal (e.g. acceptable loss of facility life or low voltage), otherwise, such a violation will necessitate creation of a requirement.

6 Following the first contingency (N-1), the generation must be sufficient to allow the operators to bring the system back to within acceptable (normal) operating range (voltage and loading) and/or appropriate OTC following the studied outage conditions.

7 During normal operation or following the first contingency (N-1), the generation must be sufficient to allow the operators to prepare for the next worst N-1 or common mode N-2 without pre-contingency interruptible or firm load shedding. SPS/RAS/Safety Nets may be utilized to satisfy the criteria after the second N-1 or common mode N-2 except if the problem is of a thermal nature such that short-term ratings could be utilized to provide the operators time to shed either interruptible or firm load. T-2s (two transformer bank outages) would be excluded from the criteria.

2. Post Transient Load Flow Assessment:

Contingencies Selected [1]	Reactive Margin Criteria [2] Applicable Rating

[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 the higher of imports or load increase by 5% for N-1 contingencies, and 2.5% for N-2 contingencies.

3. Stability Assessment:

Contingencies Selected [1]	Stability Criteria [2] Applicable Rating

[1] Base on historical information, engineering judgment and/or if power flow or post transient study results indicate significant low voltages or marginal reactive margin for a given contingency.

[2] Applicable Rating – ISO Grid Planning Criteria or facility owner criteria as appropriate.

B. Methodology for Determining Zonal Requirements

A key part of the CAISO's study for determining capacity requirements in transmission-constrained areas includes **zonal requirements** to ensure that sufficient generation capacity (in MWs) exists within each large zone so that transmission constraints between zones do not threaten reliability. The analysis of zonal requirements was discussed in the CPUC workshops and the 2006 Local Capacity Technical Analysis (page 5), but the methodology for determining these zonal requirements was not explained in detail.

The CAISO's methodology for determining these zonal requirements is designed so the operating reserves within each zone meet the WECC Minimum Operating Reliability Criteria (MORC) for operating reserves.[9]

[9] *MORC states "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."*

The determination of these zonal requirements is dependent upon key assumptions:

- **Forecasted Load:** Consistent with CAISO Planning Standards, the CAISO proposes a forecasted zonal load level that represents the 1-in-5-year peak conditions (more specifically the zonal area "coincident" peak.) For future studies the CAISO expects to use the CEC's 1-in-5 year peak load forecasts.

- **Import Capability:** the maximum MW amount that is assumed can be imported into a zone. This can be calculated based on the maximum historical imports into a zone, plus the anticipated increase in import capability due to transmission upgrades in effect for the time period being analyzed. This includes capacity from outside the CAISO Control Area and capacity between the zones, e.g. Path 26.

- **Outages**: the amount of generation that may be unavailable within a zone due to unforeseen circumstances that require immediate maintenance. Assuming a peak load, this assumption would encompass forced outages as well as a very small amount of planned outages.

- **Recovery from a Single Worst Contingency:** enough operating reserve to recover from the most severe single contingency without relying on firm load shedding. This total reserve capacity is based on the set of assumptions for peak load conditions. Existing industry standards do not permit shedding firm load to address a single contingency.

The zonal requirement (i.e., the amount of MWs needed within each region) is determined simply by calculating the sum of the operating reserves for recovery from a single worst contingency, the historical outage data, and the 1-in-5-year peak forecast, subtracted by the import capability:

1 in 5 zonal Load forecast + Historical outage data + Recovery from single worst contingency – Import Capability = Zonal Requirement

Zonal requirements define the amount of generation (in MWs) that should exist within a region to ensure the system's ability to withstand a single worst contingency. The CAISO should focus on the 500kV system only between three major zones: NP15, NP15+ZP26, and south of Path 26 (SP26.) These are historically defined regions of the CAISO Controlled Grid where inter-zonal transmission constraints have been prone to deficiencies. Generation within all the local areas within these zones would count toward meeting a zonal requirement.

C. Load Forecast

1. System Forecast

The load forecast at the system as well as PTO levels originates from California Energy Commission (CEC). This most recent CEC forecast is then distributed across the entire system, down to the local area, division and substation level. PTO's use an econometric equation to forecast the system load. The predominant parameters affecting the system load are (1) number of households, (2) economic activity (gross metropolitan products, GMP), (3) temperature and (4) increased energy efficiency and distributed generation programs.

2. Base Case Load Development Method

The method used to develop the base case loads is a melding process that extracts, adjusts and modifies the information from the system, distribution and muni forecasts. The melding process consists of two parts. Part 1 deals with the PTO load. Part 2 deals with the muni load. There may be small differences between the methodologies used by each PTO to disaggregate the CEC load forecast to their level of local area as well as bar-bus model; please refer to each PTO expansion plan for additional details.

a. PTO Loads in Base Case

The methods used to determine the PTO loads are for the most part similar. One part of the method deals with the determination of the division loads that would meet the requirements of 1-in-5 or 1-in-10 system or area base cases and the other part deals with the allocation of the division load to the transmission buses.

i. Determination of division loads

The annual division load is determined by summing the previous year division load and the current division load growth. Thus the key steps are the determination of the initial year division load and the annual load growth. The initial year for the base case development method is based heavily on recorded data. The division load growth in the system base case is determined in two steps. First, the total PTO load growth for the year is determined, as the product of the PTO load and the load growth rate from the system load forecast. Then this total PTO load growth is allocated to the division, based on the relative magnitude of the load growths projected for the divisions by the distribution planners. For example the 1-in-10 area base case, the division load growth determined for the system base case is adjusted to the 1-in-10 temperature using the load temperature relation determined from the latest peak load and temperature data of the division.

ii. Allocation of division load to transmission bus level

Since the base case loads are modeled at the various transmission buses, the division loads developed would need to be allocated to those buses. The allocation process is different depending on the load types. For the most part each PTO's classifies its loads into four types: conforming, non-conforming, self-generation and generation-plant loads. Since the non-conforming and self-generation loads are assumed to not vary with temperature, their magnitude would be the same in the system or area base cases of the same year. The remaining load (the total division load developed above, less the quantity of non-conforming and self-generation load) is the conforming load. The remaining load would be allocated to the transmission buses based on the relative magnitude of the distribution forecast. The summation of all base case loads usually is higher then the load forecast because some load like self-generation and generation-plant are load behind the meter and they need to be modeled in the base cases, however for the most part metered or aggregated data with telemetry is used to come up with the load forecast.

b. Municipal Loads in Base Case

The muni forecasts provided to the PTOs for the purposes of their base cases were used for this study.

3. Comparison between the 1-in 5 and 1-in-10 local load forecast

As a rule of thumb, this difference translates into a corresponding one-for-one reduction in the LCR -- (the MWs of capacity needed in that local area) -- provided that the area constraint is driven by a <u>thermal</u> problem AND assuming that the load and generation have roughly the same effectiveness factors.

The exact reduction in LCR results (using a less stringent 1-in-5-year instead of the 1-in-10-year load forecast) could be different due to the load growth characteristics specific to each local area. If the local area constraints are non-linear, like voltage or dynamic problems, or if the effectiveness factors between the generators and load within the same area are significantly different relative to the worst thermal constraint, then the difference in LCR results will not mirror the difference in load forecast.

Table 2: 2007 Local Area Load Forecast 1-in 5 vs 1-in-10

	Peak Load (1 in 10) (MW)	Peak Load (1 in 5) (MW)	Difference (MW)	Difference (%)
Humboldt	197	196	1	0.5
North Coast/North Bay	1,513	1,475	38	2.5
Sierra	1,841	1,805	36	2.0
Stockton	1,267	1,252	15	1.2
Greater Bay	9,633	9,509	124	1.3
Greater Fresno	3,154	3,004	150	4.8
Kern	1,209	1,174	35	2.9
LA Basin	19,325	18,809	516	2.7
San Diego	4,742	4,610	134	2.8
Total	**42,881***	**41,834***	**1,049**	**2.4**

*** Value shown only illustrative, since each local area peaks at a different time.**

The peak load forecast is one key variable in the determination of the LCR that meets the established criteria. In comparing the 1-in-5-year load analysis with the 1-in-10-year standard, a general conclusion that could be drawn is that the difference in required MWs for most of the local areas and sub-areas analyzed in this report would not be huge. An analysis of each local area and the unique contingencies within each area would be necessary to determine the exact difference in LCR's.

D. Power Flow Program Used in the LCR analysis

The LCR technical studies were conducted using General Electric's Power System Load Flow (GE PSLF) program version 15.2. This E PSLF program is available directly from GE or through the Western System Electricity Council (WECC) to any member.

The CAISO utilized the "2007 Heavy Summer 2A1" as the starting WECC base case for the 2007 local area power flows used in the 2007 LCR studies. To complete the local area component of this study, this base case was adjusted to reflect the latest generation and transmission projects as well as the one-in-ten-year peak load forecast for each local area as provided to the ISO by the Participating Transmission Owners ("PTOs").

Electronic contingency files provided by the PTOs were utilized to perform the numerous contingencies required to identify the LCR needs. These contingency files include remedial action and special protection schemes that are expected to be in operation during 2007. An CAISO created EPCL (a GE programming language contained within the GE PSLF package) routine was used to run the combination of contingencies; however, other routines are available from WECC with the GE PSFL package or can be developed by third parties to identify the most limiting combination of contingencies requiring the highest amount of generation within the local area to maintain power flows within applicable ratings.

IV. Locational Capacity Requirement Study Results

A. Summary of Study Results

The LCR results reflect two sets of generation. The first set is comprised of generation that would normally be expected to be on-line such as Municipal generation and Regulatory Must-take generation (State, Federal, QFs and nuclear units). The second set is "market" generation. Within this overview, LCR is defined as the amount of generating capacity that is required within a Local Capacity Area to reliably serve the load located within this area.

The results of the CAISO's analysis are summarized in the following two tables.

Table 3: Local Requirements Comparison

	Qualifying Capacity			2007 LCR Requirement Based on Category B Option 1			2007 LCR Requirement Based on Category C with operating procedure Option 2			2006 Total LCR Req.
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**(MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**	162
North Coast / North Bay	158	861	1019	582**	0	**582****	582**	0	**582****	658
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**	1770*
Stockton	314	257	571	432	0	**432**	536	53	**589**	440*
Greater Bay	1314	5231	6545	4771	0	**4771**	4771**	0	**4771****	6009
Greater Fresno	575	2337	2912	2115	0	**2115**	2151	68	**2219**	2837 *
Kern	978	31	1009	554	0	**554**	769	17	**786**	797*
LA Basin	3510	7012	10522	8843	0	**8843**	8843	0	**8843**	8127
San Diego	191	2741	2932	2781	0	**2781**	2781	0	**2781**	2620
Total	**8185**	**19379**	**27564**	**22113**	**205**	**22318**	**22468**	**466**	**22934**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR
** The North Coast/North Bay and Bay Area requirements would have been higher by 80 and 570 MW respectively, however two new operating procedures have been received, validated and implemented by PG&E and the CAISO.

The last column under "2007 LCR Requirement based on Category C with operating solution" represents the MW of generation that the ISO is proposing to be procured by all LSEs in local areas under the CPUC Local Capacity Requirements. This column includes all units needed to maintain system reliability without the potential for pre-contingency load shedding.

Table 4: Local Capacity Requirements vs. Peak Load and Local Area Generation

	2007 Total LCR (MW)	Peak Load (1 in10) (MW)	2007 LCR as % of Peak Load	Total Dependable Local Area Generation (MW)	2007 LCR as % of Total Area Generation
Humboldt	202	197	103%	206	98%
North Coast/North Bay	582	1,513	38%	1,019	57%
Sierra	2,161	1,841	117%	1,848	117%**
Stockton	589	1,267	46%	571	103%**
Greater Bay	4,771	9,633	50%	6,545	73%
Greater Fresno	2,219	3,154	70%	2,912	76%**
Kern	786	1,209	65%	1,009	78%**
LA Basin	8,843	19,325	46%	10,522	84%
San Diego	2,781	4,742	59%	2,932	95%
Total	**22,934**	**42,881***	**53%***	**27,471**	**83%**

*** Value shown only illustrative, since each local area peaks at a different time.**

** Generation deficient LCA (or with sub-area that are deficient) – deficiency included in LCR. Generator deficient area implies that in order to comply with the criteria, at summer peak, load must be shed immediately after the first contingency.

Table 3 shows how much of the local area load is dependent on local generation and how much local generation needs to be available in order to reliably (see LCR criteria) serve the load in those Local Capacity Areas. This table also indicates where new transmission projects, new generation additions or demand side management programs would be most useful in order to reduce the dependency on existing (mostly old and inefficient) local area generation.

B. Summary of Results by Local Area

Each local area's overall requirement is determined by also achieving each sub-area requirement. Because these areas are a part of the interconnected electric system, the total for each local area is not simply a summation of the sub-area requirements. For example, some sub-areas may overlap and therefore the same units have been counted toward both sub-area requirements. Of course some sub-areas requirements are directly counted toward the total requirements of a bigger local area or the overall area.

1. Humboldt Area

<u>Area Definition</u>

The transmission tie lines into the area include:

1) Bridgeville-Cottonwood 115 kV line #1
2) Humboldt-Trinity 115 kV line #1
3) Willits-Garberville 60 kV line #1
4) Trinity-Maple Creek 60 kV line #1

The substations that delineate the Humboldt Area are:

1) Bridgeville 115 kV
2) Humboldt 115 kV
3) Kekawaka 60 kV
4) Ridge Cabin 60 kV

Total busload within the defined area: 191 MW with 6 MW of losses resulting in total load + losses of 197 MW.

Total units and qualifying capacity available in this area:

Gen Bus	Gen Name	ID	Qualifying Capacity (MW)
31170	HMBOLDT1	1	51
31172	HMBOLDT2	1	52
31154	HUMBOLDT	1	15
31154	HUMBOLDT	2	15
31150	FAIRHAVN	1	17.2

31166	KEKAWAK	1	5.3
31158	LP SAMOA	1	25
31152	PAC.LUMB	2	12.5
31152	PAC.LUMB	1	12.5
	Total		205.5

Critical Contingency Analysis Summary

Humboldt overall:

The most critical contingency for the Humboldt area is the outage of the Bridgeville-Cottonwood 115 kV line over-lapping with an outage of one Humboldt Bay Power Plant. The local area limitation is low voltage and reactive power margin. This multiple contingency establishes a Local Capacity Requirement of 202 MW (includes 73 MW of QF/Selfgen generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

Humboldt Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	73	0	133	206

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[10]	202	0	202
Category C (Multiple)[11]	202	0	202

[10] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[11] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

2. North Coast / North Bay Area

Area Definition

The North Coast/North Bay Area is composed of two sub-areas and the generation requirements within them.

The transmission tie facilities coming into the Eagle Rock-Fulton sub-area are:

1) Fulton-Lakeville 230 kV line #1
2) Fulton-Ignacio 230kV line #1
3) Cortina 230/115 kV Transformer #1
4) Lakeville-Sonoma 115 kV line #1
5) Corona-Lakeville 115 kV line #1
6) Willits-Garberville 60 kV line #1

The substations that delineate the Eagle Rock-Fulton sub-area are:

1) Fulton 230 kV
2) Corona 115 kV
3) Sonoma 115 kV
4) Cortina 115 kV
5) Laytonville 60 kV

The transmission tie lines into the Lakeville sub-area are:

1) Vaca Dixon-Lakeville 230 kV line #1
2) Tulucay-Vaca Dixon 230 kV line #1
3) Lakeville-Sobrante 230 kV line #1
4) Ignacio-Sobrante 230 kV line #1
5) Ignacio-Fulton 230 kV line #1
6) Lakeville-Fulton 230 kV line #1
7) Lakeville-Corona 115 kV line #1
8) Lakeville-Sonoma 115 kV line #1

The substations that delineate the Lakeville sub-area are:

1) Lakeville 230 kV
2) Ignacio 230 kV
3) Tulucay 230 kV
4) Lakeville 115 kV

Total busload within the defined area: 1457 MW with 56 MW of losses resulting in total load + losses of 1513 MW.

Total units and qualifying capacity available in this area:

Gen Bus	Gen Name	ID	Qualifying Capacity (MW)
31433	POTTRVLY	3	2.5
31433	POTTRVLY	1	5.5
31433	POTTRVLY	4	2.5
31430	SMUDGEO1	1	38
31406	GEYSR5-6	1	36
31406	GEYSR5-6	2	36
31408	GEYSER78	1	31
31408	GEYSER78	2	31
31412	GEYSER11	1	60
31414	GEYSER12	1	41
31416	GEYSER13	1	70
31418	GEYSER14	1	63
31420	GEYSER16	1	75
31422	GEYSER17	1	51
31424	GEYSER18	1	40
31426	GEYSER20	1	40
38106	NCPA1GY1	1	59
38108	NCPA1GY2	1	59
38110	NCPA2GY1	1	60
38112	NCPA2GY2	1	60
31400	SANTA FE	2	39.1
31404	WEST FOR	2	14
31400	SANTA FE	1	39.1
31402	BEAR CAN	1	8.3
31402	BEAR CAN	2	8
31404	WEST FOR	1	14
32700	MONTICLO	1	3.3
32700	MONTICLO	2	3.4
32700	MONTICLO	3	0
31435	GEO.ENGY	1	8.6
31435	GEO.ENGY	2	8.9
31436	INDIAN V	1	3.7
31446	SONMA LF	1	7.7
	Total		1018.6

Critical Contingency Analysis Summary

Eagle Rock-Fulton Sub-area

The most critical overlapping contingency is the outage of the Fulton-Ignacio 230 kV line #1 and the Fulton-Lakeville 230 kV line #1. The sub-area area limitation is thermal overloading of Sonoma-Pueblo 115 kV line #1. This limiting contingency establishes a Local Capacity Requirement of 371 MW (includes 80 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area. Out of this amount, 182 MW is required among the units connected directly to the Eagle Rock substation (includes 21 MW of QF generation).

The most critical single contingency in the sub-area is the outage of Cortina 230/115 kV transformer #1. This limiting contingency establishes a Local Capacity Requirement of 245 MW (includes 80 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within the Eagle Rock-Fulton pocket as well as units outside the pocket that are at least 5% effective to the above-mentioned constraint.

Single contingency

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31404	WEST FOR	2	56	Fulton
31404	WEST FOR	1	56	Fulton
31414	GEYSER12	1	56	Fulton
31418	GEYSER14	1	56	Fulton
31420	GEYSER16	1	56	Fulton
31422	GEYSER17	1	56	Fulton
38110	NCPA2GY1	1	56	Fulton
38112	NCPA2GY2	1	56	Fulton
31406	GEYSR5-6	1	53	Eagle Rock
31406	GEYSR5-6	2	53	Eagle Rock
31408	GEYSER78	1	53	Eagle Rock
31408	GEYSER78	2	53	Eagle Rock
31412	GEYSER11	1	53	Eagle Rock

Overlapping Contingency

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31404	WEST FOR	2	27	Fulton
31404	WEST FOR	1	27	Fulton
31414	GEYSER12	1	27	Fulton
31418	GEYSER14	1	27	Fulton
31420	GEYSER16	1	27	Fulton
31422	GEYSER17	1	27	Fulton

38110	NCPA2GY1	1	27	Fulton
38112	NCPA2GY2	1	27	Fulton
31406	GEYSR5-6	1	17	Eagle Rock
31406	GEYSR5-6	2	17	Eagle Rock
31408	GEYSER78	1	17	Eagle Rock
31408	GEYSER78	2	17	Eagle Rock
31412	GEYSER11	1	17	Eagle Rock

Lakeville Sub-area

Operations solutions to mitigate the most limiting constraint in the Lakeville pocket, as previously described in the LCR report, has been validated in this area in order to reduce the total LCR requirement both under single and overlapping contingency conditions. After implementing the operating solutions, the most critical contingency for Lakeville sub-area would be the outage of Vaca Dixon-Tulucay 230 kV line #1 and Geysers 13 unit. The sub-area limitation is thermal overloading of the Lakeville-Vaca-Dixon 230 kV #1. This limiting contingency establishes a Local Capacity Requirement of 582 MW for single contingency in this sub-area (includes 158 MW of QF generation). The LCR requirement for Eagle Rock/Fulton sub-area can be counted toward fulfilling the requirement of Lakeville sub-area.

Effectiveness factors:

The following table has units at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr	Location
31400	SANTA FE	2	25	Lakeville
31430	SMUDGEO1	1	25	Lakeville
31400	SANTA FE	1	25	Lakeville
31416	GEYSER13	1	25	Lakeville
31424	GEYSER18	1	25	Lakeville
31426	GEYSER20	1	25	Lakeville
38106	NCPA1GY1	1	25	Lakeville
38108	NCPA1GY2	1	25	Lakeville
31404	WEST FOR	2	22	Fulton
31404	WEST FOR	1	22	Fulton
31414	GEYSER12	1	22	Fulton
31418	GEYSER14	1	22	Fulton
31420	GEYSER16	1	22	Fulton
31422	GEYSER17	1	22	Fulton
38110	NCPA2GY1	1	22	Fulton

38112	NCPA2GY2	1	22	Eagle Rock
31406	GEYSR5-6	1	8	Eagle Rock
31406	GEYSR5-6	2	8	Eagle Rock
31408	GEYSER78	1	8	Eagle Rock
31408	GEYSER78	2	8	Eagle Rock
31412	GEYSER11	1	8	Eagle Rock

North Coast/North Bay Overall Requirements:

	QF/Seflgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	158	0	861	1019

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[12]	582	0	582
Category C (Multiple)[13]	582	0	582

3. Sierra Area

<u>Area Definition</u>

The transmission tie lines into the Sierra Area are:

1) Table Mountain-Rio Oso 230 kV line
2) Table Mountain-Palermo 230 kV line
3) Table Mt-Pease 60 kV line
4) Caribou-Palermo 115 kV line
5) Drum-Summit 115 kV line #1
6) Drum-Summit 115 kV line #2
7) Spaulding-Summit 60 kV line
8) Brighton-Bellota 230 kV line
9) Rio Oso-Lockeford 230 kV line
10) Gold Hill-Eight Mile Road 230 kV line
11) Gold Hill-Lodi Stig 230 kV line
12) Gold Hill-Lake 230 kV line

The substations that delineate the Sierra Area are:

1) Table Mountain 60 kV
2) Table Mountain 230 kV

[12] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[13] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

3) Big Bend 115 kV
4) Drum 115 kV
5) Tamarack 60 kV
6) Brighton 230 kV
7) Rio Oso 230 kV
8) Gold Hill 230 kV

Total busload within the defined area: 1742.4 MW with 98.5 MW of losses resulting in total load + losses of 1840.9 MW.

Total units and qualifying capacity available in this area:

Gen No	Gen Name	ID	Qualifying Capacity
31888	OROVLLE	1	8.9
31890	PO POWER	2	9.8
31890	PO POWER	1	9.8
31834	KELLYRDG	1	10
31814	FORBSTWN	1	39.7
31794	WOODLEAF	1	55
31862	DEADWOOD	1	2
31832	SLY.CR.	1	13.2
32470	CMP.FARW	1	6.5
32450	COLGATE1	1	165.8
32452	COLGATE2	1	165.7
32466	NARROWS1	1	3.6
32468	NARROWS2	1	10.1
32451	FREC	1	47
32490	GRNLEAF1	2	10
32490	GRNLEAF1	1	51.1
32156	WOODLAND	1	28.6
32494	YUBA CTY	1	50.2
32496	YCEC	1	47
32492	GRNLEAF2	1	50.3
32166	UC DAVIS	1	3.5
31812	CRESTA	1	35
31812	CRESTA	2	35
31788	ROCK CK2	1	56
31820	BCKS CRK	1	33
31820	BCKS CRK	2	25
31790	POE 1	1	60
31792	POE 2	1	60
31786	ROCK CK1	1	56
31784	BELDEN	1	115
32162	RIV.DLTA	1	3.1
32502	DTCHFLT2	1	26
32476	ROLLINSF	1	11.7
32474	DEER CRK	1	5.7
32454	DRUM 5	1	49.5
32504	DRUM 1-2	1	13

32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	14
32506	DRUM 3-4	2	14
32484	OXBOW F	1	6
32472	SPAULDG	1	4.4
32472	SPAULDG	2	7
32472	SPAULDG	3	5.8
32498	SPILINCF	1	13.7
32464	DTCHFLT1	1	22
32500	ULTR RCK	1	28.5
32480	BOWMAN	1	3.8
32488	HAYPRES+	1	12.3
32488	HAYPRES+	2	8.7
32462	CHI.PARK	1	38
32478	HALSEY F	1	11
32512	WISE	1	10.8
32460	NEWCSTLE	1	5.9
32510	CHILIBAR	1	7
32513	ELDRADO1	1	10
32514	ELDRADO2	1	10
32458	RALSTON	1	86
32456	MIDLFORK	1	63.4
32456	MIDLFORK	2	63.4
32486	HELLHOLE	1	0.5
32508	FRNCH MD	1	17
			1848

<u>Critical Contingency Analysis Summary</u>

South of Table Mountain Sub-area

The most critical contingency is the loss of the Table Mountain-Rio Oso 230 kV line with one of the Colgate Units out of service. The area limitation is thermal overloading of the Table Mt-Palermo 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 1630 MW (includes 1072 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
31888	OROVLLE	1	8.9	72
31890	PO POWER	2	9.8	72
31890	PO POWER	1	9.8	72
31834	KELLYRDG	1	10	72
31814	FORBSTWN	1	39.7	62
31794	WOODLEAF	1	55	62
31862	DEADWOOD	1	2	61
31832	SLY.CR.	1	13.2	61

32470	CMP.FARW	1	6.5	54
32450	COLGATE1	1	165.8	52
32452	COLGATE2	1	165.7	52
32466	NARROWS1	1	3.6	52
32468	NARROWS2	1	10.1	52
32451	FREC	1	47	42
32490	GRNLEAF1	2	10	41
32490	GRNLEAF1	1	51.1	41
32156	WOODLAND	1	28.6	28
32494	YUBA CTY	1	50.2	27
32496	YCEC	1	47	27
32492	GRNLEAF2	1	50.3	27
32166	UC DAVIS	1	3.5	26
31812	CRESTA	1	35	24
31812	CRESTA	2	35	24
31788	ROCK CK2	1	56	24
31820	BCKS CRK	1	33	24
31820	BCKS CRK	2	25	24
31790	POE 1	1	60	24
31792	POE 2	1	60	24
31786	ROCK CK1	1	56	24
31784	BELDEN	1	115	23
32162	RIV.DLTA	1	3.1	21
32502	DTCHFLT2	1	26	21
32476	ROLLINSF	1	11.7	20
32474	DEER CRK	1	5.7	20
32454	DRUM 5	1	49.5	20
32504	DRUM 1-2	1	13	20
32504	DRUM 1-2	2	13	20
32506	DRUM 3-4	1	14	20
32506	DRUM 3-4	2	14	20
32484	OXBOW F	1	6	20
32472	SPAULDG	1	4.4	20
32472	SPAULDG	2	7	20
32472	SPAULDG	3	5.8	20
32498	SPILINCF	1	13.7	20
32464	DTCHFLT1	1	22	20
32500	ULTR RCK	1	28.5	19
32480	BOWMAN	1	3.8	19
32488	HAYPRES+	1	12.3	19
32488	HAYPRES+	2	8.7	19
32462	CHI.PARK	1	38	19
32478	HALSEY F	1	11	19
32512	WISE	1	10.8	19
32460	NEWCSTLE	1	5.9	18
32510	CHILIBAR	1	7	17
32513	ELDRADO1	1	10	17
32514	ELDRADO2	1	10	17
32458	RALSTON	1	86	17
32456	MIDLFORK	1	63.4	17

32456	MIDLFORK	2	63.4	17
32486	HELLHOLE	1	0.5	16
32508	FRNCH MD	1	17	16
			1848	

Colgate Sub-area
The most critical contingency is the loss of the Colgate-Smartville #1 60 kV line with one of the Narrows #2 (or Camp far West) units out of service. The area limitation is thermal overloading of the Colgate-Smartville #2 60 kV line. This limiting contingency establishes a Local Capacity Requirement of 17 MW (includes 17 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Narrows #2 and Camp Far West) are needed therefore no effectiveness factor is required.

Pease Sub-area
The most critical contingency is the loss of the Palermo-East Nicolaus 115 kV line with one of the Greenleaf #2 (or Yuba City) units out of service. The area limitation is thermal overloading of the Palermo-Pease 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 111 MW (includes 100 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Greenleaf #2, Yuba City and Yuba City EC) are needed therefore no effectiveness factor is required.

Bogue Sub-area
The most critical contingency is the loss of the Pease-Rio Oso 115 kV line with one of the Greenleaf #1 (or Feather River EC) units out of service. The area limitation is thermal overloading of the Palermo-Bogue 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 101 MW (includes 61 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Greenleaf #1 units 1&2 and Feather River EC) are needed therefore no effectiveness factor is required.

South of Palermo Sub-area
The most critical contingency is the loss of the Double Circuit Tower Line Table Mountain-Rio Oso and Colgate-Rio Oso 230 kV lines. The area limitation is thermal

overloading of the Palermo-East Nicolaus 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 1037 MW (includes 142 MW of QF and Muni generation as well as 250 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Palermo-Pease 115 kV line with Belden unit out of service. The area limitation is thermal overloading of the Palermo-East Nicolaus 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 980 MW (includes 142 MW of QF and Muni generation as well as 193 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The Sierra case provided had a normal overload on the Palermo-East Nicolaus 115 kV line that can be resolved by changing the normal tap point for the East Marysville substation from the Palermo-East Nicolaus 115 kV line to the Pease-Rio Oso 115 kV line and by having at least 680 MW of generation on-line (from maximum 787 MW generation available – includes 142 MW of QF and Muni).

Effectiveness factors:

All units (listed below) within this area are needed therefore no effectiveness factor is required.

Gen No	Gen Name	ID	Qualifying Capacity
32476	ROLLINSF	1	11.7
32474	DEER CRK	1	5.7
32504	DRUM 1-2	1	13
32504	DRUM 1-2	2	13
32506	DRUM 3-4	1	14
32506	DRUM 3-4	2	14
32454	DRUM 5	1	49.5
32484	OXBOW F	1	6
32472	SPAULDG	1	4.4
32472	SPAULDG	2	7
32472	SPAULDG	3	5.8
32480	BOWMAN	1	3.8
32488	HAYPRES+	1	12.3
32488	HAYPRES+	2	8.7
32156	WOODLAND	1	28.6
32166	UC DAVIS	1	3.5
32502	DTCHFLT2	1	26
32464	DTCHFLT1	1	22
32162	RIV.DLTA	1	3.1
32462	CHI.PARK	1	38
31812	CRESTA	1	35
31812	CRESTA	2	35
31788	ROCK CK2	1	56
31820	BCKS CRK	1	33

31820	BCKS CRK	2	25
31790	POE 1	1	60
31792	POE 2	1	60
31786	ROCK CK1	1	56
31784	BELDEN	1	115
32478	HALSEY F	1	11
32512	WISE	1	10.8
			786.9

Placerville Sub-area

The most critical contingency is the loss of the Gold Hill-Clarksville 115 kV line followed by loss of the Gold Hill-Missouri Flat #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Missouri Flat #1 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 83 MW (includes 0 MW of QF and Muni generation as well as 56 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (El Dorado units 1&2 and Chili Bar) are needed therefore no effectiveness factor is required.

Placer Sub-area

The most critical contingency is the loss of the Drum-Higgins 115 kV line followed by loss of the Gold Hill-Placer #2 115 kV line. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 123 MW (includes 0 MW of QF and Muni generation as well as 95 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Drum-Higgins 115 kV line with the Wise #1 unit out of service. The area limitation is thermal overloading of the Gold Hill-Placer #1 115 kV line. This limiting contingency establishes a Local Capacity Requirement of 52 MW (includes 0 MW of QF and Muni generation as well as 24 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area (Wise units 1&2, Newcastle and Halsey) are needed therefore no effectiveness factor is required.

Drum-Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso #2 230/115 transformer followed by loss of the Rio Oso-Brighton 230 kV line. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes a Local Capacity Requirement of 701 MW (includes 413 MW of QF and Muni generation as well as 45 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Rio Oso #2 230/115 transformer. The area limitation is thermal overloading of the Rio Oso #1 230/115 kV transformer. This limiting contingency establishes a Local Capacity Requirement of 352 MW (includes 413 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area are needed for the most limiting contingency therefore no effectiveness factor is required. Effectiveness factors are given for the single most limiting contingency.

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
32156	WOODLAND	1	28.6	31
32490	GRNLEAF1	2	10	29
32490	GRNLEAF1	1	51.1	29
32451	FREC	1	47	28
32166	UC DAVIS	1	3.5	25
32502	DTCHFLT2	1	26	20
32476	ROLLINSF	1	11.7	19
32474	DEER CRK	1	5.7	18
32454	DRUM 5	1	49.5	18
32504	DRUM 1-2	1	13	18
32504	DRUM 1-2	2	13	18
32506	DRUM 3-4	1	14	18
32506	DRUM 3-4	2	14	18
32484	OXBOW F	1	6	18
32472	SPAULDG	1	4.4	18
32472	SPAULDG	2	7	18
32472	SPAULDG	3	5.8	18
32480	BOWMAN	1	3.8	18
32488	HAYPRES+	1	12.3	18
32488	HAYPRES+	2	8.7	18
32496	YCEC	1	47	16
32494	YUBA CTY	1	50.2	16
32492	GRNLEAF2	1	50.3	16
32464	DTCHFLT1	1	22	15
32162	RIV.DLTA	1	3.1	15
32462	CHI.PARK	1	38	12
31862	DEADWOOD	1	2	7
31814	FORBSTWN	1	39.7	7
31832	SLY.CR.	1	13.2	7
31794	WOODLEAF	1	55	7
			655.6	

South of Rio Oso Sub-area

The most critical contingency is the loss of the Rio Oso-Gold Hill 230 line followed by loss of the Gold Hill-Ralston 230 kV line or vice versa. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 230 MW (includes 80 MW of QF and Muni generation as well as 95 MW of Deficiency) as the minimum capacity necessary for reliable load serving capability within this pocket.

The single most critical contingency is the loss of the Rio Oso-Gold Hill 230 line with the Ralston unit out of service. The area limitation is thermal overloading of the Rio Oso-Atlantic 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 132 MW (includes 80 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this pocket.

Effectiveness factors:

All units within this area are needed for the most limiting contingency therefore no effectiveness factor is required. Effectiveness factors are given for the second most limiting contingency.

Gen No	Gen Name	ID	Qualifying Capacity	DFAX (%)
32498	SPILINCF	1	13.7	50
32500	ULTR RCK	1	28.5	49
32514	ELDRADO2	1	10	33
32513	ELDRADO1	1	10	33
32510	CHILIBAR	1	7	33
32460	NEWCSTLE	1	5.9	27
32478	HALSEY F	1	11	25
32512	WISE	1	10.8	25
32462	CHI.PARK	1	38	9
			134.9	

Sierra Overall Requirements:

	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	267	805	776	1848

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[14]	1833	205	2038
Category C (Multiple)[15]	1833	328	2161

[14] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[15] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

4. Stockton Area

Area Definition

The transmission facilities that establish the boundary of the Tesla-Bellota Sub-area are:

1) Bellota 230/115 kV Transformer #1
2) Bellota 2

30/115 kV Transformer #2

3) Tesla-Tracy 115 kV Line
4) Tesla-Salado 115 kV Line
5) Tesla-Salado-Manteca 115 kV line
6) Tesla-Shulte 115 kV Line
7) Tesla-Kasson-Manteca 115 kV Line

The substations that delineate the Tesla-Bellota Sub-area are:

1) Tesla 115 kV
2) Bellota 115 kV

The transmission facilities that establish the boundary of the Lockeford Sub-area are:

1) Lockeford-Industrial 60 kV line
2) Lockeford-Lodi #1 60 kV line
3) Lockeford-Lodi #2 60 kV line
4) Lockeford-Lodi #3 60 kV line

The substations that delineate the Lockeford Sub-area is:

1) Lockeford 60 kV

The transmission facilities that establish the boundary of the Stagg Sub-area are:

1) Tesla – Stagg 230 kV Line
2) Tesla – Eight Mile Road 230 kV Line
3) Gold Hill – Eight Mile Road 230 kV Line
4) Gold Hill - Lodi Stigg 230 kV Line

The substations that delineate the Stagg Sub-area is:

1) Tesla 230 kV
2) Gold Hill 230 kV

Total busload within the defined area: 1240 MW with 27 MW of losses resulting in total load + losses of 1267 MW.

Total units and qualifying capacity available in this area:

Name	ID	Qualifying Capacity
GWFTRCY2	1	79.2
GWFTRCY1	1	79.8
FBERBORD	1	5.7
BELLTA T	1	0
CH.STN.	1	22.3
STNSLSRP	1	19.9
CPC STCN	1	62.9
CAMANCHE	1	3.7
CAMANCHE	2	3.7
CAMANCHE	3	3.7
DONNELLS	1	67.5
BEARDSLY	1	11
TULLOCH	1	9
TULLOCH	2	9
SANDBAR	1	16.8
SPRNG GP	1	6.7
STANISLS	1	91
LODI25CT	1	25.6
GEN.MILL	1	3.4
Stig CC	1	50
		570.9

Critical Contingency Analysis Summary

Stockton overall

The requirement for this area is driven by the sum of requirements for the Tesla-Bellota, Lockeford, and Stagg Sub-areas.

Tesla-Bellota Sub-area

The critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Tracy 115 kV and Tesla-Schulte 115 kV #1. The area limitation is thermal overloading of the Manteca-Ingram Creek section of Tesla-Salado-Manteca 115 kV line above its emergency rating. This limiting contingency establishes a Local Capacity Requirement of 458 MW (includes 235 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

The single most critical contingency for the Tesla-Bellota pocket is the loss of Tesla-Kasson-Manteca 115 kV line and the loss of the Stanislaus unit #1. This single contingency establishes a Local Capacity Requirement of 432 MW (includes 235 MW of QF and Muni generation).

Effectiveness factors:

All units within this area are needed for the most limiting contingency therefore no effectiveness factor is required.

Lockeford Sub-area

The critical contingency for the Lockeford area is the loss of Lockeford-Industrial 60 kV circuit and Lockeford-Lodi #2 60 kV circuit. The area limitation is thermal overloading of the Lockeford-Colony section of the Lockeford-Lodi #1 60 kV circuit. This limiting contingency establishes a Local Capacity Requirement of 81 MW (including 28 MW of QF and Muni as well as a deficiency of 53 MW) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area (Lodi CT and General Mill) are needed therefore no effectiveness factor is required.

Stagg Sub-area

The outage of the Tesla-Stagg 230 kV line and Tesla-Eight Mile 230 kV line causes low voltages at Stagg, Eight Mile Road and Lodi Stig 230 kV busses. Post-contingency steady-state voltages at these three busses are less than 0.90 pu. Lodi Stig generating unit is needed to support voltage at these three 230 kV busses. This limiting contingency establishes a Local Capacity Requirement of 50 MW as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

The only unit within this area (Lodi Stig) is needed therefore no effectiveness factor is required.

Stockton Overall Requirements:

	QF (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	114	200	257	571

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[16]	432	0	432
Category C (Multiple)[17]	536	53	589

[16] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

5. Greater Bay Area

Area Definition

The transmission tie lines into the Greater Bay Area are:

1) Lakeville-Sobrante 230 kV
2) Ignacio-Sobrante 230 kV
3) Parkway-Moraga 230 kV
4) Bahia-Moraga 230 kV
5) Lambie SW Sta-Vaca Dixon 230 kV
6) Peabody-Contra Costa P.P. 230 kV
7) Kelso-Brentwood 230 kV
8) Tesla-Delta Switching Yard 230 kV
9) Tesla-Pittsburg #1 230 kV
10) Tesla-Pittsburg #2 230 kV
11) Tesla-Newark #1 230 kV
12) Tesla-Newark #2 230 kV
13) Tesla-Tracy #1 230 kV
14) Tesla-Tracy #2 230 kV
15) Tesla-Ravenswood 230 kV
16) Tesla-Metcalf 500 kV
17) Moss Landing-Metcalf 500 kV
18) Moss Landing-Metcalf #1 230 kV
19) Moss Landing-Metcalf #2 230 kV
20) Green Valley-Morgan Hill #1 115 kV
21) Green Valley-Morgan Hill #2 115 kV
22) Oakdale TID-Newark #1 115 kV
23) Oakdale TID-Newark #2 115 kV

The substations that delineate the Greater Bay Area are:

1) Lakeville 230 kV
2) Ignacio 230 kV
3) Moraga 230 kV
4) Lambie SW Sta 230 kV
5) Kelso 230 kV
6) Peabody 230 kV
7) Pittsburg 230 kV
8) Tesla 230 kV
9) Metcalf 500 kV
10) Moss Landing 500 kV

---

[17] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

11) Morgan Hill 115 kV
12) Newark 115 kV

Total busload within the defined area: 9402 MW with 231 MW of losses resulting in total load + losses of 9633 MW.

Total units and qualifying capacity available in this area:

No	Name	ID	Qualifying Capacity
38118	ALMDACT1	1	25.6
38119	ALMDACT2	1	25.6
33114	C.COS 4	1	0
33115	C.COS 5	1	0
33116	C.COS 6	1	345
33117	C.COS 7	1	345
33463	CARDINAL	2	10
33463	CARDINAL	1	17.8
35863	CATALYST	1	0
36856	CCA100	1	32
33136	CCCSD	1	4.4
32921	ChevGen1	1	54
32922	ChevGen2	1	54
36854	Cogen	2	3
36854	Cogen	1	3
32900	CRCKTCOG	1	243
32175	CREEDGT1	3	47
33145	CROWN.Z.	2	5.4
33145	CROWN.Z.	1	40
33108	DEC CTG1	1	173
33109	DEC CTG2	1	173
33110	DEC CTG3	1	173
33107	DEC STG1	1	294
33161	DOWCHEM1	1	16.8
33162	DOWCHEM2	1	22
33163	DOWCHEM3	1	22
36863	DVR A GT	1	47
36865	DVR A ST	1	50
36864	DVR B GT	1	50
35318	FLOWDPTR	1	5.7
33151	FOSTER W	3	35
33151	FOSTER W	1	45.4
33151	FOSTER W	2	45.4
36858	Gia100	1	21
36895	Gia200	1	21
35850	GLRY COG	2	40
35850	GLRY COG	1	80
32174	GOOSEHGT	2	46

35851	GROYPKR1	1	45
35852	GROYPKR2	1	45
35853	GROYPKR3	1	45
33131	GWF #1	1	20
33132	GWF #2	1	20
33133	GWF #3	1	20
33134	GWF #4	1	20
33135	GWF #5	1	20
32172	HIGHWNDS	1	13
32740	HILLSIDE	1	26.2
35637	IBM-CTLE	1	50
32173	LAMBGT1	1	47
35854	LECEFGT1	1	48
35855	LECEFGT2	1	48
35856	LECEFGT3	1	48
35857	LECEFGT4	1	48
35310	LFC FIN+	1	8.9
33112	LMECCT1	1	165
33111	LMECCT2	1	165
33113	LMECST1	1	230
35881	MEC CTG1	1	184
35882	MEC CTG2	1	186
35883	MEC STG1	1	227
33121	MRAGA 1T	1	0
33122	MRAGA 2T	1	0
33123	MRAGA 3T	1	0
32901	OAKLND 1	1	55
32902	OAKLND 2	1	55
32903	OAKLND 3	1	55
35860	OLS-AGNE	1	28.5
33252	POTRERO3	1	210
33253	POTRERO4	1	52
33254	POTRERO5	1	52
33255	POTRERO6	1	52
33105	PTSB 5	1	320
33106	PTSB 6	1	325
30000	PTSB 7	1	710
33178	RVEC_GEN	1	48
35312	SEAWESTF	1	3.3
33141	SHELL 1	1	20
33142	SHELL 2	1	40
33143	SHELL 3	1	40
32176	SHILOH	1	0
35861	SJ-SCL W	1	5
33462	SMATO1SC	1	0
33460	SMATO2SC	1	0
33461	SMATO3SC	1	0
32169	SOLANOWP	1	10

33468	SRI INTL	1	3.3
33139	STAUFER	1	2.3
32920	UNION CH	1	20.4
32910	UNOCAL	1	10
32910	UNOCAL	2	10
32910	UNOCAL	3	10
33466	UNTED CO	1	27.2
35320	USW FRIC	1	3.4
35320	USW FRIC	2	0
32168	USWINDPW	2	3.4
33838	USWP_#3	1	20.5
33170	WINDMSTR	1	3.6
35316	ZOND SYS	1	6.2
			6545

Critical Contingency Analysis Summary

San Francisco Sub-area

Per the CAISO Revised Action Plan for SF, all Potrero units (360 MW) will continued to be required until completion of the plan as it is presently described.

The most critical contingency is an overlapping outage of two 115 kV cables between Martin and Hunters Point Substations. The area limitation is thermal overloading of the Martin-Bayshore-Potrero 115 kV #1 and #2 cables. This limiting contingency requires all of the existing Potrero Power plant generation (Potrero units 3-6) 360 MW be on-line.

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

Oakland Sub-area

The most critical contingency is an outage of the D-L 115 kV cable (with one of the Oakland CT's off-line)
The sub-area area limitation is thermal overloading of the C-X 115 kV cableThis limiting contingency establishes a Local Capacity Requirement of 100 MW (includes 50 MW of Muni generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area have the same effectiveness factor. Units outside of this sub-area are not effective.

Llagas Sub-area

The most critical contingency is an outage between Metcalf D and Morgan Hill 115 kV (with one of the Gilroy Peaker off-line). The area limitation is thermal overloading of the Metcalf-Llagas 115 kV line. As documented within a CAISO Operating Procedure, this limitation is dependent on power flowing in the direction from Metcalf to Llagas/Morgan Hill. This limiting contingency establishes a Local Capacity Requirement of 100 MW as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

San Jose Sub-area

The most critical contingency is the category C outage of Evergreen 1 – Markham – San Jose B 115 kV line and the Metcalf D – IBM HR – El Patio 115 kV line. The area limitation is thermal overloading of the Baily J3 – El Patio 115 kV line.This contingency prevents the Metcalf E 115 bus from feeding the San Jose B 115 kV load. Power must flow through the remaining Metcalf D – El Patio 115 kV circuit and then to the load at San Jose B 115 kV bus. This limiting contingency establishes a Local Capacity Requirement of 457 MW (including 265 MW of QF and Muni generation) as the minimum capacity necessary for reliable load serving capability for this outage.

Effectiveness factors:

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

Name	ID	Qualifying Capacity
Cogen	2	3
Cogen	1	3
DVR A ST	1	51
DVR B GT	1	48.4
DVR A GT	1	48.4
Gia100	1	21
LECEFGT4	1	48
LECEFGT3	1	48
LECEFGT2	1	48
LECEFGT1	1	48
IBM-CTLE	1	50
OLS-AGNE	1	29
SJ-SCL W	1	5.5
CCA100	1	35.9
CATALYST	1	2

	Gia200	1	21
			510.2

Pittsburg Sub-area

The most critical contingency is an outage of the Pittsburg-Tesla #1 or #2 230 kV line (with Delta Energy Center off-line).

The sub-area area limitation is thermal overloading of the parallel Pittsburg-Tesla 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 2208 MW (including 678 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within the Pittsburg pocket as well as units outside the pocket that are at least 5% effective to the above-mentioned constraint.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
33840	FLOWD3-6	1	86
33840	FLOWD3-6	2	86
33840	FLOWD3-6	3	86
33840	FLOWD3-6	4	86
33171	TRSVQ+NW	2	26
33171	TRSVQ+NW	1	26
33105	PTSB 5	1	26
33106	PTSB 6	1	26
30000	PTSB 7	1	26
33110	DEC CTG3	1	25
33109	DEC CTG2	1	25
33108	DEC CTG1	1	25
33107	DEC STG1	1	25
33113	LMECST1	1	24
33112	LMECCT1	1	24
33111	LMECCT2	1	24
33132	GWF #2	1	24
33161	DOWCHEM1	1	24
33162	DOWCHEM2	1	24
33163	DOWCHEM3	1	24
33151	FOSTER W	1	23
33151	FOSTER W	2	23
33151	FOSTER W	3	23
33141	SHELL 1	1	21
33143	SHELL 3	1	21
33142	SHELL 2	1	21
32900	CRCKTCOG	1	19
32910	UNOCAL	1	19
32910	UNOCAL	2	19
32910	UNOCAL	3	19

32920	UNION CH	1	19
32922	ChevGen2	1	18
32921	ChevGen1	1	18
32740	HILLSIDE	1	18
33135	GWF #5	1	18
38119	ALMDACT2	1	16
32903	OAKLND 3	1	16
32902	OAKLND 2	1	16
32901	OAKLND 1	1	16
38118	ALMDACT1	1	16
31404	WEST FOR	2	14
31402	BEAR CAN	1	14
31402	BEAR CAN	2	14
31404	WEST FOR	1	14
31414	GEYSER12	1	14
31416	GEYSER13	1	14
31418	GEYSER14	1	14
31420	GEYSER16	1	14
31422	GEYSER17	1	14
31424	GEYSER18	1	14
31426	GEYSER20	1	14
38110	NCPA2GY1	1	14
38112	NCPA2GY2	1	14
31400	SANTA FE	2	13
31430	SMUDGEO1	1	13
31400	SANTA FE	1	13
38106	NCPA1GY1	1	13
38108	NCPA1GY2	1	13
31406	GEYSR5-6	1	10
31406	GEYSR5-6	2	10
31408	GEYSER78	1	10
31408	GEYSER78	2	10
31412	GEYSER11	1	10
31435	GEO.ENGY	1	10
31435	GEO.ENGY	2	10
30464	EXXON_BH	1	9
33252	POTRERO3	1	7
33271	HNTRS P1	1	7
33270	HNTRS P4	1	7
33253	POTRERO4	1	7
33254	POTRERO5	1	7
33255	POTRERO6	1	7
33466	UNTED CO	1	7
35312	SEAWESTF	1	7
35316	ZOND SYS	1	7
35320	USW FRIC	1	7
32176	SHILOH	1	5
36865	DVRPPSTA	1	5

36864	DVRPPCT2	1	5
36863	DVRPPCT1	1	5
32185	WOLFSKIL	1	5
33178	RVEC_GEN	1	5
32175	CREEDGT1	3	5
32174	GOOSEHGT	2	5
32173	LAMBGT1	1	5
32150	DG_VADIX	1	5
32172	HIGHWNDS	1	5
33134	GWF #4	1	5
33116	C.COS 6	1	5
33117	C.COS 7	1	5
32154	WADHAM	1	5
33133	GWF #3	1	5
33145	CROWN.Z.	1	5
33145	CROWN.Z.	2	5
33131	GWF #1	1	5
36856	CSC_CCA	1	5
33463	CARDINAL	1	5
33463	CARDINAL	2	5
32168	USWINDPW	1	5
32168	USWINDPW	2	5
33838	USWP_#3	1	5

Bay Area overall

PG&E has proposed and the CAISO has validated and implemented a new operating procedure. As such the LCR need for the most critical contingency: the loss of the Vaca Dixon 500/230 kV transformer followed by loss of the Contra Costa unit 7 or vice versa, has been reduced.

As a result the most critical contingency is the loss of the Vaca Dixon 500/230 kV transformer. The area limitation is thermal overloading of the Tesla-Delta Switching Yard 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 4771 MW (includes 1314 MW of Wind, QF and Muni generation) as the minimum capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

For most helpful procurement information please read procedure T-133Z effectiveness factors – Bay Area at:
http://www.caiso.com/docs/2004/11/01/2004110116234011719.pdf

Bay Area Overall Requirements:

	Wind (MW)	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	78	988	248	5231	6545

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[18]	4771	0	4771
Category C (Multiple)[19]	4771	0	4771

6. Greater Fresno Area

Area Definition

The transmission facilities coming into the Greater Fresno area are:

1) Gates-Henrietta Tap 1 230 kV
2) Gates-Henrietta Tap 2 230 kV
3) Gates #1 230/115 kV Transformer Bank
4) Los Banos #3 230/70 Transformer Bank
5) Los Banos #4 230/70 Transformer Bank
6) Panoche-Gates #1 230 kV
7) Panoche-Gates #2 230 kV
8) Panoche-Coburn 230 kV
9) Panoche-Moss Landing 230 kV
10) Panoche-Los Banos #1 230 kV
11) Panoche-Los Banos #2 230 kV
12) Panoche-Dos Amigos 230 kV
13) Warnerville-Wilson 230 kV
14) Wilson-Melones 230 kV
15) Corcoran – Alpaugh - Smyrna 115 kV
16) Coalinga #1-San Miguel 70 kV

The substations that delineate the Greater Fresno area are:

1) Los Banos 230 kV
2) Gates 230 kV
3) Panoche 230 kV
4) Wilson 230 kV
5) Alpaugh 115 kV
6) Coalinga 70 kV

Total busload within the defined area: 3051 MW with 103 MW of losses resulting in total load + losses of 3154 MW.

Total units and qualifying capacity available in this area:

---

[18] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[19] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

No	Name	ID	Qualifying Capacity
34636	FRIANTDM	4	3.5
34636	FRIANTDM	3	8.7
34636	FRIANTDM	2	16.3
34608	AGRICO	2	7
34608	AGRICO	3	18.9
34608	AGRICO	4	26
34672	KRCDPCT2	1	56
34671	KRCDPCT1	1	56
34485	FRESNOWW	1	9
34142	WHD_PAN2	1	49
34553	WHD_GAT2	1	49
34179	MADERA_G	1	28.7
34433	GWF_HEP2	1	39.1
34431	GWF_HEP1	1	40
34541	GWF_GT2	1	45.1
34539	GWF_GT1	1	45.3
34186	DG_PAN1	1	49
34301	CHOWCOGN	1	52.5
34618	MCCALL1T	1	0
34621	MCCALL3T	1	0
34630	HERNDN1T	1	0
34632	HERNDN2T	1	0
38720	PINE FLT	1	75
38720	PINE FLT	2	75
38720	PINE FLT	3	75
34306	EXCHQUER	1	70.8
34658	WISHON	1	5
34658	WISHON	2	5
34658	WISHON	3	5
34658	WISHON	4	5
34344	KERCKHOF	1	8.5
34344	KERCKHOF	2	13
34344	KERCKHOF	3	12.8
34308	KERCKHOF	1	155
34600	HELMS 1	1	404
34602	HELMS 2	1	404
34604	HELMS 3	1	404
34610	HAAS	1	69.9
34610	HAAS	2	69.9
34624	BALCH 1	1	34
34612	BLCH 2-2	1	52.5
34614	BLCH 2-3	1	52.5
34616	KINGSRIV	1	52
34316	ONEILPMP	1	11
34320	MCSWAIN	1	3.9

34322	MERCEDFL	1	1.9
34658	WISHON	SJ	0.4
34631	SJ2GEN	1	3.2
34633	SJ3GEN	1	4.2
34332	JRWCOGEN	1	8.5
34334	BIO PWR	1	26.1
34640	ULTR.PWR	1	26.4
34642	KINGSBUR	1	35.3
34646	SANGERCO	1	42.9
34648	DINUBA E	1	13.5
34650	GWF-PWR.	1	25
34652	CHV.COAL	1	4.1
34652	CHV.COAL	2	14.8
34654	COLNGAGN	1	42.3
34342	INT.TURB	1	1.1
			2912

Critical Contingency Analysis Summary

Wilson Sub-area

The most critical contingency for the Wilson sub-area is the loss of the Wilson - Melones 230 kV line with one of the Helm units out of service, which would thermally overload the Wilson - Warnerville 230 kV line. This limiting contingency establishes a Local Capacity Requirement of 1449 MW (which includes 75 MW of muni generation and 215 MW of QF generation) as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within Fresno that are at least 5% effective to the above-mentioned constraint. All units in Fresno not listed or units outside of this area have smaller effectiveness factors.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
34332	JRWCOGEN	1	40
34322	MERCEDFL	1	33
34320	MCSWAIN	1	32
34306	EXCHQUER	1	31
34600	HELMS 1	1	31
34602	HELMS 2	1	31
34604	HELMS 3	1	31
34301	CHOWCOGN	1	29
34636	FRIANTDM	1	25
34485	FRESNOWW	1	24
34658	WISHON	1	24
34658	WISHON	2	24

34658	WISHON	3	24
34658	WISHON	4	24
34631	SJ2GEN	1	24
34633	SJ3GEN	1	23
34344	KERCKHOF	1	22
34344	KERCKHOF	2	22
34344	KERCKHOF	3	22
34308	KERCKHOF	1	22
34179	MADERA_G	1	20
34648	DINUBA E	1	19
34672	KRCDPCT2	1	18
34671	KRCDPCT1	1	18
34624	BALCH 1	1	18
34640	ULTR.PWR	1	18
34646	SANGERCO	1	18
38720	PINE FLT	1	17
38720	PINE FLT	2	17
38720	PINE FLT	3	17
34616	KINGSRIV	1	17
34642	KINGSBUR	1	17
34433	GWF_HEP2	1	14
34431	GWF_HEP1	1	14
34610	HAAS	1	14
34610	HAAS	2	14
34612	BLCH 2-2	1	14
34614	BLCH 2-3	1	14
34539	GWF_GT1	1	13
34334	BIO PWR	1	13
34541	GWF_GT2	1	12
34650	GWF-PWR.	1	12
34142	WHD_PAN2	1	11
34186	DG_PAN1	1	11
34608	AGRICO	2	10
34608	AGRICO	3	10
34608	AGRICO	4	10
34553	WHD_GAT2	1	8
34652	CHV.COAL	1	8
34652	CHV.COAL	2	8
34654	COLNGAGN	1	8
34342	INT.TURB	1	6
34316	ONEILPMP	1	6

Herndon Sub-area

Generation curtailment has been done as part of the system readjustment that occurs between the first contingency and the second contingency. As such the LCR need for the most critical contingency in the Herndon sub-area: the loss of the

Herndon 230/115 kV bank 1 with Kerckhoff #2 unit out of service, which would thermally overload the parallel Herndon 230/115 kV bank 2, has been reduced.

As a result the most critical contingency for the Herndon sub-area is the loss of the Herndon 230/115 kV bank 1, which would thermally overload the parallel Herndon 230/115 kV bank 2. This limiting contingency establishes a Local Capacity Requirement of 719 MW (which includes 149 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units within Fresno area that have at least 5% relative effectiveness to the above-mentioned constraint. All units in Fresno not listed or units outside of this area have smaller effectiveness factors.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
34308	KERCKHOF	1	36
34344	KERCKHOF	1	35
34344	KERCKHOF	2	35
34344	KERCKHOF	3	35
34624	BALCH 1	1	33
34646	SANGERCO	1	32
34672	KRCDPCT2	1	31
34671	KRCDPCT1	1	31
34616	KINGSRIV	1	31
34640	ULTR.PWR	1	31
34648	DINUBA E	1	29
34642	KINGSBUR	1	26
38720	PINE FLT	1	22
38720	PINE FLT	2	22
38720	PINE FLT	3	22
34612	BLCH 2-2	1	22
34610	HAAS	1	21
34610	HAAS	2	21
34614	BLCH 2-3	1	21
34433	GWF_HEP2	1	14
34431	GWF_HEP1	1	14
34301	CHOWCOGN	1	9
34608	AGRICO	2	7
34608	AGRICO	3	7
34608	AGRICO	4	7
34334	BIO PWR	1	3
34652	CHV.COAL	1	3
34652	CHV.COAL	2	3
34553	WHD_GAT2	1	2
34179	MADERA_G	1	2

34654	COLNGAGN	1	2
34332	JRWCOGEN	1	-5
34485	FRESNOWW	1	-13
34600	HELMS 1	1	-15
34602	HELMS 2	1	-15
34604	HELMS 3	1	-15

McCall Sub-area

The most critical contingency for the McCall sub-area is the loss of Mc Call #3 230/115 kV transformer bank with GWF Hanford Peaker #1 unit out of service, which would thermally overload the McCall #2 230/115 kV transformer bank. This limiting contingency establishes a Local Capacity Requirement of 1,462 MW (which includes 192 MW of QF generation and 108 MW of Muni generation) as the generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the McCall sub-area is the loss of Mc Call #3 230/115 kV transformer bank, which would thermally overload the McCall #2 230/115 kV transformer bank. This limiting contingency establishes a Local Capacity Requirement of 1,405 MW (which includes 192 MW of QF generation and 108 MW of Muni generation).

Effectiveness factors:

See line 6 under attached link below.

Henrietta Sub-area

The most critical contingency for the Henrietta sub-area is the loss of new Henrietta 230/70 kV transformer bank with Henrietta-GWF Henrietta 70 kV line out of service, which would thermally overload the old Henrietta 230/70 kV transformer bank. This combined limit establishes a Local Capacity Requirement of 117 MW (which includes 25 MW of QF generation and 2 MW of deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Henrietta sub-area is the loss of new Henrietta 230/70 kV transformer bank, which would thermally overload the old Henrietta 230/70 kV transformer bank. This combined limit establishes a Local Capacity Requirement of 34 MW (which includes 25 MW of QF generation).

Effectiveness factors:

All units within this sub-area have the same effectiveness factor. Units outside of this sub-area are not effective.

Merced Sub-area

The most critical contingencies for the Merced sub-area is the double line outage of the Wilson – Atwater 115 kV #1 and #2 lines, which would thermally overload the Wilson – Merced 115 kV #1 and #2 lines. This limiting contingency establishes a Local Capacity Requirement of 151 MW (which includes 75 MW of muni generation, 9 MW of QF generation and 66 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

No	Name	ID	Qualifying Capacity
34306	EXCHQUER	1	70.8
34320	MCSWAIN	1	3.9
34322	MERCEDFL	1	1.9
34332	JRWCOGEN	1	8.5

Because of the overlapping LCR MWs requirements among the sub-areas, the total aggregate LCR requirement for the Greater Fresno Area is 2219 MW (includes 108 MW of muni generation, 222 MW of QF generation and 68 MW of deficiency).

Additional helpful effectiveness factors for Fresno area:

Please read procedure T-129Z effectiveness factors - Fresno Area at: http://www.caiso.com/docs/2005/07/13/2005071314483315210.pdf

Fresno Area Overall Requirements:

	QF/Selfgen (MW)	Muni (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	275	300	2337	2912

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[20]	2115	0	2115
Category C (Multiple)[21]	2151	68	2219

7. Kern Area

<u>Area Definition</u>

[20] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

[21] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

The transmission facilities coming into the Kern PP sub-area are:

1) Wheeler Ridge-Lamont 115 kV line
2) Kern PP 230/115 kV Bank # 3 & 3A
3) Kern PP 230/115 kV Bank # 4
4) Kern PP 230/115 kV Bank # 5
5) Midway 230/115 Bank # 1
6) Midway 230/115 Bank # 2 & 2a
7) Temblor – San Luis Obispo 115 kV line

These sub-stations form the boundary surrounding the Kern PP sub-area:

1) Midway 115 kV
2) Kern PP 115 kV
3) Wheeler Ridge 115 kV
4) Temblor 115 kV

The transmission facilities coming into the Weedpatch sub-area are:

1) Wheeler Ridge 115/60 kV Bank
2) Wheeler Ridge 230/60 kV Bank

These sub-stations form the boundary surrounding the Weedpatch sub-area:

1) Wheeler Ridge 60 kV

Total busload within the defined area: 1191 MW with 18 MW of losses resulting in total load + losses of 1209 MW.

Total units and qualifying capacity available in this Kern PP sub-area:

No	Name	ID	Qualifying Capacity
35056	TX-LOSTH	1	9
35034	MIDSUN +	1	20
35037	UNIVRSTY	1	39.9
35038	CHLKCLF+	1	49.9
35006	KERN 1	1	0
35008	KERN 2	1	0
35024	DEXEL +	1	32.1
35026	KERNFRNT	1	52.7
35029	BADGERCK	1	48.9
35027	HISIERRA	1	52.7
35023	DOUBLE C	1	51.9
35028	OILDALE	1	40.1
35032	CHV-CYMR	1	22.7
34783	TEXCO_NM	1	12
34783	TEXCO_NM	2	9

35036	MT POSO	1	56.1
35035	ULTR PWR	1	36.4
35040	KERNRDGE	1	66
35040	KERNRDGE	2	14.2
35044	TX MIDST	1	39.8
35046	SEKR	1	34.2
35048	FRITOLAY	1	7.1
35050	SLR-TANN	1	17.4
35052	CHEV.USA	1	14.4
35058	PSE-LVOK	1	49
35060	PSEMCKIT	1	50.8
35062	DISCOVRY	1	44
35064	NAVY 35R	1	31.9
35064	NAVY 35R	2	32.5
35066	PSE-BEAR	1	51.3
	Total		986

Total units and qualifying capacity available in this Kern PP sub-area:

No	Name	ID	Qualifying Capacity
35018	KERNCNYN	1	11.2
35020	RIOBRAVO	1	12.1
	Total		23.3

<u>Critical Contingency Analysis Summary</u>

Kern PP Sub-area

The most critical contingency for the Kern PP sub-area is the outage of the Kern PP #5 230/115 kV transformer bank and the Kern PP – Kern Front 115 kV line, which would thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity Requirement of 749 MW (which includes 749 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

The most critical single contingency for the Kern PP sub-area is the loss of Kern PP #5 230/115 kV transformer bank, which would thermally overload the parallel Kern PP 230/115 kV Bank 3 and Bank 3a. This limiting contingency establishes a Local Capacity Requirement of 554 MW (which includes 554 MW of QF generation) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area are under long-term contracts. No additional procurement needs to be done; therefore no effectiveness factor is required.

Wheedpatch Sub-area

The most critical contingency is the loss of the Wheeler Ridge – San Bernard 70 kV line and the Wheeler Ridge – Tejon 70 kV line, which would thermally overload the Wheeler Ridge – Weedparch 70 kV line and cause low voltage problem at the local 70 kV transmission system. This limiting contingency establishes a Local Capacity Requirement of 36 MW (which includes 8 MW of QF generation and 17 MW of area deficiency) as the minimum generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

All units within this sub-area are needed therefore no effectiveness factor is required.

Kern Area Overall Requirements:

	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	978	31	1009

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[22]	554	0	554
Category C (Multiple)[23]	769	17	786

8. LA Basin Area

<u>Area Definition</u>

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines
2) San Onofre - Talega #1 & #2 230 kV Lines
3) Lugo - Mira Loma #1, #2 & #3 500 kV Lines
4) Sylmar LA - Sylmar S #1, #2 & #3 230/230 kV Transformers
5) Sylmar S - Pardee #1 & #2 230 kV Lines
6) Vincent - Mesa Cal #1 230 kV Line
7) Antelope - Mesa Cal #1 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee #1 230 kV Line
10) Devers - Valley #1 500 kV Line

[22] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[23] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

11) Devers #1 & #2 500/230 kV Transformers
12) Devers - Coachelv # 1 230 kV Line
13) Mirage - Ramon # 1 230 kV Line
14) Julian Hinds-Eagle Mountain 230 kV

These sub-stations form the boundary surrounding the LA Basin area:

1) Devers 500 kV
2) Mirage 230 kV
3) Vincent 230 kV
4) San Onofre 230 kV
5) Sylmar 230 kV
6) Lugo 500 kV

Total busload within the defined area is 19055 MW with 173 MW of losses and 97 MW of pumps resulting in total load + losses of 19325 MW.

Total units and qualifying capacity available in the Eastern sub-area:

BUS-NO	NAME1	ID	Qualifying Capacity	Subarea
24052	MTNVIST3	3	319	Eastern LA Basin
24053	MTNVIST4	4	320	Eastern LA Basin
28190	WINTECX2	1	44	Eastern LA Basin
28191	WINTECX1	1	42	Eastern LA Basin
28180	WINTEC8	1	42	Eastern LA Basin
24921	MNTV-CT1	1	143.5	Eastern LA Basin
24922	MNTV-CT2	1	143.5	Eastern LA Basin
24923	MNTV-ST1	1	249	Eastern LA Basin
24924	MNTV-CT3	1	143.5	Eastern LA Basin
24925	MNTV-CT4	1	143.5	Eastern LA Basin
24926	MNTV-ST2	1	249	Eastern LA Basin
25632	TERAWND	1	1	Eastern LA Basin
25633	CAPWIND	1	1	Eastern LA Basin
25634	BUCKWND	1	1	Eastern LA Basin
25635	ALTWIND	1	2.9	Eastern LA Basin
25636	RENWIND	1	1	Eastern LA Basin
25637	TRANWND	1	2.9	Eastern LA Basin
25639	SEAWIND	1	3	Eastern LA Basin
25640	PANAERO	1	1.9	Eastern LA Basin
25645	VENWIND	1	1.9	Eastern LA Basin
25646	SANWIND	1	1	Eastern LA Basin
24826	INDIGO	1	17	Eastern LA Basin
24815	GARNET	1	1	Eastern LA Basin
28020	WINTEC6	1	1.9	Eastern LA Basin
28060	SEAWEST	1	1.9	Eastern LA Basin
28060	SEAWEST	2	1.9	Eastern LA Basin

28280	CABAZON	1	1.9	Eastern LA Basin
24030	DELGEN	1	33.1	Eastern LA Basin
24071	INLAND	1	19.7	Eastern LA Basin
24140	SIMPSON	1	34	Eastern LA Basin
24902	VSTA	1	0	Eastern LA Basin
24229	VALLEY-S	1	0	Eastern LA Basin
25991	VALYSVC2	1	0	Eastern LA Basin
25990	VALYSVC1	1	0	Eastern LA Basin
24902	VSTA	2	1.3	Eastern LA Basin
24214	SANBRDNO	2	0.5	Eastern LA Basin
24214	SANBRDNO	1	0.1	Eastern LA Basin
24055	ETIWANDA	2	34.7	Eastern LA Basin
24055	ETIWANDA	1	0.6	Eastern LA Basin
25422	ETI MWDG	1	23.7	Eastern LA Basin
28061	WHITEWTR	1	52.8	Eastern LA Basin
28260	ALTAMSA4	1	32	Eastern LA Basin
24160	VALLEYSC	1	4.2	Eastern LA Basin
24111	PADUA	2	5.8	Eastern LA Basin
24111	PADUA	1	0.5	Eastern LA Basin
24024	CHINO	1	9.9	Eastern LA Basin
25648	DVLCYN1G	1	50.7	Eastern LA Basin
25649	DVLCYN2G	2	50.7	Eastern LA Basin
25603	DVLCYN3G	1	67.7	Eastern LA Basin
25604	DVLCYN4G	2	67.7	Eastern LA Basin
	Total		2371.9	

Total units and qualifying capacity available in the Western sub-area:

BUS-NO	NAME1	ID	PMAX	Subarea
24001	ALAMT1 G	1	174.6	Western LA Basin
24002	ALAMT2 G	2	175	Western LA Basin
24003	ALAMT3 G	3	332.2	Western LA Basin
24004	ALAMT4 G	4	335.7	Western LA Basin
24005	ALAMT5 G	5	485	Western LA Basin
24161	ALAMT6 G	6	495	Western LA Basin
24162	ALAMT7 G	7	0	Western LA Basin
25203	ANAHEIMG	1	46.6	Western LA Basin
24018	BRIGEN	1	35	Western LA Basin
24020	CARBOGEN	1	29	Western LA Basin
24047	ELSEG3 G	3	335	Western LA Basin
24048	ELSEG4 G	4	335	Western LA Basin
24066	HUNT1 G	1	225.8	Western LA Basin
24067	HUNT2 G	2	225.8	Western LA Basin
24167	HUNT3 G	3	225	Western LA Basin
24168	HUNT4 G	4	227.4	Western LA Basin
24120	PULPGEN	1	40	Western LA Basin
24121	REDON5 G	5	178.9	Western LA Basin

24122	REDON6 G	6	175	Western LA Basin
24123	REDON7 G	7	493.2	Western LA Basin
24124	REDON8 G	8	486.9	Western LA Basin
24133	SANTIAGO	1	17	Western LA Basin
24062	HARBOR G	0	88.6	Western LA Basin
25510	HARBORG4	LP	5.7	Western LA Basin
24062	HARBOR G	HP	5.7	Western LA Basin
24011	ARCO 1G	1	64.7	Western LA Basin
24012	ARCO 2G	2	64.7	Western LA Basin
24013	ARCO 3G	3	64.7	Western LA Basin
24014	ARCO 4G	4	64.7	Western LA Basin
24163	ARCO 5G	5	31.2	Western LA Basin
24164	ARCO 6G	6	31.2	Western LA Basin
24022	CHEVGEN1	1	0.8	Western LA Basin
24023	CHEVGEN2	2	0.8	Western LA Basin
24026	CIMGEN	1	26.1	Western LA Basin
24063	HILLGEN	1	37.3	Western LA Basin
24070	ICEGEN	1	46.2	Western LA Basin
24139	SERRFGEN	1	25.2	Western LA Basin
24203	CENTER S	1	25.2	Western LA Basin
24075	LAGUBELL	1	11.2	Western LA Basin
24073	LA FRESA	1	5.7	Western LA Basin
24094	MOBGEN	1	45	Western LA Basin
24064	HINSON	1	25.2	Western LA Basin
24027	COLDGEN	1	28	Western LA Basin
24060	GROWGEN	1	28	Western LA Basin
24169	HUNT5 G	5	0	Western LA Basin
24213	RIOHONDO	1	0.9	Western LA Basin
24209	MESA CAL	1	0.6	Western LA Basin
24208	LCIENEGA	1	2.3	Western LA Basin
24083	LITEHIPE	1	0.3	Western LA Basin
24028	DELAMO	1	0	Western LA Basin
24157	WALNUT	1	7.9	Western LA Basin
28005	PASADNA1	1	22.5	Western LA Basin
28006	PASADNA2	1	22.5	Western LA Basin
28007	BRODWYSC	1	65	Western LA Basin
24211	OLINDA	1	2.3	Western LA Basin
24197	ELLIS	1	7.1	Western LA Basin
24129	S.ONOFR2	2	1115	Western LA Basin
24130	S.ONOFR3	3	1105	Western LA Basin
	Total		8150.4	

<u>Critical Contingency Analysis Summary</u>

LA Basin overall:

The combined Local Area Requirement is 8843 MW of which 3510 MW includes the San Onofre Nuclear Power Plant, QF and Muni generation. The Western and

Eastern sub-area contingencies require 8843[24] MW as the minimum amount of generating capacity necessary for reliable load serving capability within these sub-areas. 2042 MW of this capacity is needed in the Eastern sub-area, and the rest (6802 MW) is needed in the Western sub-area.

The two critical contingencies in the Eastern Sub-area are: (1) Loss of Devers – Valley 500 kV line, followed by the loss of two Lugo – Mira Loma 500 kV lines #2 and #3, and (2) Loss of one San Onofre Nuclear Generator, followed by the loss of two Lugo – Mira Loma 500 kV lines #2 and #3. The sub-area area limitation is low area post-transient voltage associated with voltage collapse.

Effectiveness factors:

The area limitation is low area post-transient voltage associated with voltage collapse. The units in the Eastern area or geographically close to it are the most effective units.

The critical contingency for the in the Western Sub-area is the loss of Lugo-Victorville 500 kV, followed by loss of Sylmar-Gould 230 kV line. The sub-area area limitation is thermal overloading of the Eagle Rock-Mesa 230 kV line.

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within the LA Basin area.

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
24209	MESA CAL	1	19
24011	ARCO 1G	1	18
24012	ARCO 2G	2	18
24013	ARCO 3G	3	18
24014	ARCO 4G	4	18
24164	ARCO 6G	6	18
24047	ELSEG3 G	3	18
24048	ELSEG4 G	4	18
24121	REDON5 G	5	18
24122	REDON6 G	6	18
24123	REDON7 G	7	18
24124	REDON8 G	8	18
24163	ARCO 5G	5	17
24020	CARBOGEN	1	17
24064	HINSON	1	17
24070	ICEGEN	1	17
24094	MOBGEN	1	17

[24] This value is based on a potential higher South of Lugo (SOL) limit with RAS operation which needs to be determined by SCE. Based on the current 5600 MW SOL limit, the total LA Basin generation requirement would increase by an additional 900 MW for a total of 9743 MW to respect loss of a SONG unit.

24139	SERRFGEN	1	17
24062	HARBOR G	0	17
25510	HARBORG4	LP	17
24062	HARBOR G	HP	17
28005	PASADNA1	1	17
28006	PASADNA2	1	17
28007	BRODWYSC	1	17
24208	LCIENEGA	1	17
24083	LITEHIPE	1	17
24075	LAGUBELL	1	17
24073	LA FRESA	1	17
24028	DELAMO	1	17
24001	ALAMT1 G	1	16
24002	ALAMT2 G	2	16
24003	ALAMT3 G	3	16
24004	ALAMT4 G	4	16
24005	ALAMT5 G	5	16
24161	ALAMT6 G	6	16
24018	BRIGEN	1	16
24027	COLDGEN	1	16
24060	GROWGEN	1	16
24063	HILLGEN	1	16
24120	PULPGEN	1	16
24213	RIOHONDO	1	16
24203	CENTER S	1	16
24157	WALNUT	1	16
24167	HUNT3 G	3	15
24066	HUNT1 G	1	14
24067	HUNT2 G	2	14
24168	HUNT4 G	4	14
24133	SANTIAGO	1	14
24197	ELLIS	1	14
25203	ANAHEIMG	1	13
24026	CIMGEN	1	13
24030	DELGEN	1	13
24071	INLAND	1	13
24140	SIMPSON	1	13
25422	ETI MWDG	1	13
24902	VSTA	2	13
24111	PADUA	2	13
24111	PADUA	1	13
24024	CHINO	1	13
25648	DVLCYN1G	1	12
25649	DVLCYN2G	2	12
25603	DVLCYN3G	3	12
25604	DVLCYN4G	4	12
24052	MTNVIST3	3	12

24053	MTNVIST4	4	12
24129	S.ONOFR2	2	12
24130	S.ONOFR3	3	12
24921	MNTV-CT1	1	12
24922	MNTV-CT2	1	12
24923	MNTV-ST1	1	12
24924	MNTV-CT3	1	12
24925	MNTV-CT4	1	12
24926	MNTV-ST2	1	12
24214	SANBRDNO	2	12
24214	SANBRDNO	1	12
24055	ETIWANDA	2	12
24055	ETIWANDA	1	12
25632	TERAWND	1	11
25633	CAPWIND	1	11
25634	BUCKWND	1	11
25635	ALTWIND	1	11
25636	RENWIND	1	11
25637	TRANWND	1	11
25639	SEAWIND	1	11
25640	PANAERO	1	11
25645	VENWIND	1	11
25646	SANWIND	1	11
24826	INDIGO	1	11
28190	WINTECX2	1	11
28191	WINTECX1	1	11
28180	WINTEC8	1	11
24815	GARNET	1	11
24828	WINTEC9	1	11
28020	WINTEC6	1	11
28060	SEAWEST	1	11
28060	SEAWEST	2	11
28061	WHITEWTR	1	11
28260	ALTAMSA4	1	11
28280	CABAZON	1	11

LA Basin Overall Requirements:

	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	829	461	2220	7012	10522

	Existing Generation	Deficiency	Total MW

	Capacity Needed (MW)	(MW)	Requirement
Category B (Single)[25]	8843	0	8843
Category C (Multiple)[26]	8843	0	8843

9. San Diego Area

Area Definition

The transmission tie lines forming a boundary around San Diego include:

1) Imperial Valley – Miguel 500 kV Line
2) Miguel – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line
4) San Onofre - San Luis Rey #2 230 kV Line
5) San Onofre - San Luis Rey #3 230 kV Line
6) San Onofre – Talega #1 230 kV Line
7) San Onofre – Talega #2 230 kV Line

These sub-stations form the boundary surrounding the San Diego area:

1) Miguel 230 kV
2) San Luis Rey 230 kV
3) Talega 230 kV

Total busload within the defined area: 4637 MW with 105 MW of losses resulting in total load + losses of 4742 MW.

Total units and qualifying capacity available in this area:

No	Name	ID	Qualifying Capacity
22088	BOULEVRD	1	0.5
22092	CABRILLO	1	3.6
22172	DIVISION	1	46.9
22212	ELCAJNGT	1	15
22233	ENCINA 1	1	103.5
22234	ENCINA 2	1	104
22236	ENCINA 3	1	110
22240	ENCINA 4	1	300
22244	ENCINA 5	1	330
22248	ENCINAGT	1	15
22332	GOALLINE	1	50

[25] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[26] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

22376	KEARN3CD	1	15.3
22384	KYOCERA	1	0.1
22480	MIRAMAR	1	2.7
22488	MIRAMRGT	1	18
22532	MURRAY	1	0.5
22576	NOISLMTR	1	35.3
22660	POINTLMA	1	21.8
22680	R.SNTAFE	1	0.5
22688	RINCON	1	0.5
22704	SAMPSON	1	13.6
22724	SANMRCOS	1	1.1
22776	SOUTHBGT	1	13
22780	SOUTHBY1	1	145
22784	SOUTHBY2	1	149
22788	SOUTHBY3	1	174
22792	SOUTHBY4	1	221
22820	SWEETWTR	1	0.5
22120	CARLTNHS	1	1.1
22149	CALPK_BD	1	42
22153	CALPK_ES	1	45.5
22150	CALPK_EC	1	42
22604	OTAY	1	3
22373	KEARN2AB	1	14.8
22373	KEARN2AB	2	14.8
22374	KEARN2CD	1	14.8
22374	KEARN2CD	2	14.8
22375	KEARN3AB	1	15.3
22375	KEARN3AB	2	15.3
22376	KEARN3CD	2	15.3
22377	KEARNGT1	1	16
22488	MIRAMRGT	2	18
22074	LRKSPBD1	1	46
22075	LRKSPBD2	1	46
22257	RAMCO_ES	1	40
22617	RAMCO_OY	1	42
22834	TALEGA	SC	0
22486	RAMCO_MR	1	45
22262	PEN_CT1	1	177
22263	PEN_CT2	1	177
22265	PEN_ST	1	187
22904	CAMPOGEN	1	10
22904	CAMPOGEN	2	0
			2932

Critical Contingency Analysis Summary

San Diego overall:
The most limiting contingency in the San Diego area is described by the outage of 500 kV Southwest Power Link (SWPL) between Imperial Valley and Miguel Substations over-lapping with an outage of the Palomar Combined-Cycle Power plant (541 MW) while staying within the South of San Onofre (WECC Path 44) non-simultaneous import capability rating of 2,500 MW. Therefore the 2,781 MW (includes 181 MW of QF generation and 10 MW of wind) of capacity required within this area is predicated on having sufficient generation in the San Diego Area to reduce Path 44 to its non-simultaneous rating of 2500 MW within 30 minutes.

Effectiveness factors:

All units within this area have the same effectiveness factor. Units outside of this area are not effective.

San Diego Overall Requirements:

	QF (MW)	Wind (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	181	10	2741	2932

	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW Requirement
Category B (Single)[27]	2781	0	2781
Category C (Multiple)[28]	2781	0	2781

C. Zonal Capacity Requirements

The ISO performed an assessment of the Zonal Capacity needs for year 2007 based on the methodology presented in chapter III section B. These results refer to the ISO control area only, they do not include requirements for other control areas like: LADWP, IID, SMUD-WAPA, TID or MID.

Zone	Load Forecast (MW)	Generator Outages (MW)	Single Worst Contingency (MW)	(-)Import Capability (MW)	Total Requirement (MW)
SP26	28,778	1,500	2,000	10,100	**22,178**
NP26=NP15+ZP26	21,518	2,500	1,160	5,348	**19,830**
NP15	Path 15 is not a binding constraint at this time				

[27] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other then load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.
[28] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by MORC.

Units need in order to comply with the Local Area Capacity Requirements fully count toward the Zonal Requirements. San Diego and LA Basin are situated in SP26, Kern in ZP26 and the rest in NP15.

V. Future Annual Technical Analyses

For future local area capacity requirements studies, the CPUC should consider the use of the Loss of Load Probability (LOLP) methodology, used by many eastern regions. LOLP is a study methodology that can be used to establish the level of capacity required in each local area by performing a probabilistic analysis to achieve a specified probability for loss of load. Underlying this approach is an expected level of service reliability. In the established Eastern markets, a one-event in ten years LOLP methodology is used to determine LSE capacity obligations. The LOLP approach provides a potentially more uniform reliability result than the proposed deterministic approach. In the future, if the LOLP approach is determined to be a more desirable approach, then the LOLP analysis will be incorporated into the criteria if and when a criteria and methodology for applying it has been developed. Any LOLP criteria and methodology will need to be reviewed by stakeholders and approved by the CPUC. Until such time, the LOLP approach will not be used to establish LSE capacity requirements, and the deterministic approach defined above will be used.

California ISO
Your Link to Power

California Independent
System Operator

2007 LCR Study

Prepared By

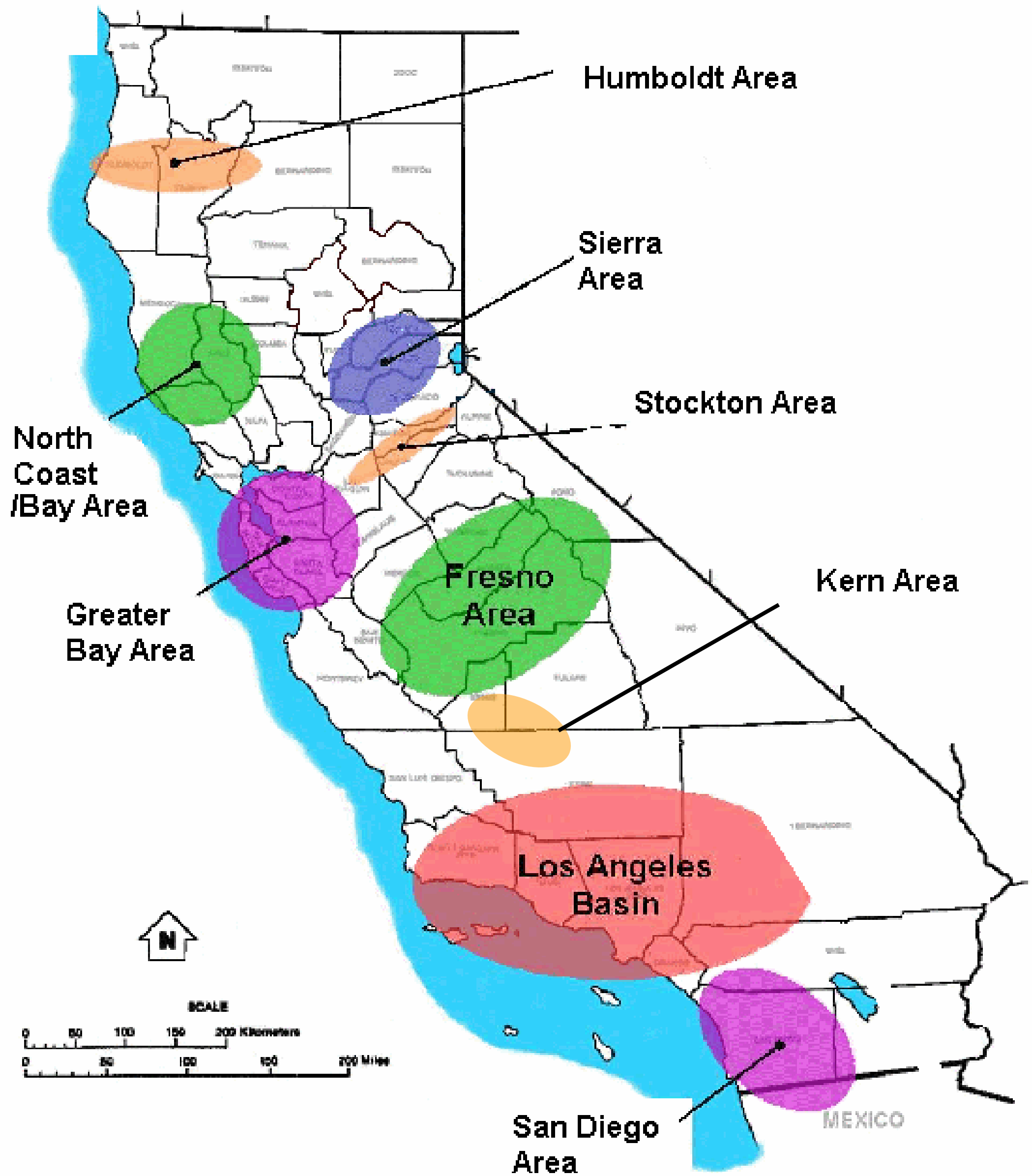
Planning & Infrastructure Development

April 26, 2006

Agenda

- Introduction
- Elements of the CAISO's Analysis
  - Input Assumptions
  - Methodology
- Summary of Findings
- Detailed Summary of Findings
- Discussion
- Next Steps

Elements of the CASIO's Analysis
Input Assumptions
Methodology
Summary of Findings


Humboldt Area
Sierra
Area
Stockton Area
North
Coast
/Bay Area
Greater
Bay Area
Fresno
Area
Kern Area
Los Angeles
Basin
San Diego
Area
MEXICO
N
SCALE

Input Assumptions

The input assumptions used were developed from a "meet and confer" session held on February 17, 2006 as well as the errata filing submitted on March 10, 2006. Administrative Law Judge adopted the proposed assumptions. This information was used in the 2007 LCR Study.

Input Assumptions:	
• Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, 2007 and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.
• Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, 2007
• Load Forecast	Uses a 1-in-10 year summer peak load forecast

Methodology

Methodology:	
• **Maximize Import Capability**	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
• **QF/Nuclear/State/Federal Units**	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at historical output values for purposes of the 2007 LCR Study.
• **Maintaining Path Flows**	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in the 2007 LCR Study is the South of Lugo transfer path flowing into the LA Basin.

Performance level

Performance Criteria:	
• **Performance Level B & C, including incorporation of PTO operational solutions**	The 2007 LCR Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, 2007. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCR Study and the resulting LCR published for this third scenario.

Load pocket & Effectiveness factors

Load Pocket:	
• **Fixed Boundary, including limited reference to published effectiveness factors**	The 2007 LCR Study has been produced based on load pockets defined by a fixed boundary. The CAISO was initially planning to publish the effectiveness factors of the generating resources within the defined load pocket as well as the effectiveness factors of the generating resources residing outside the load pocket that had a relative effectiveness factor of no less than 5% or affect the flow on the limiting equipment by more than 5% of the equipment's applicable rating. . However, after subsequent discussions with the Commission and stakeholders, and given the comments in the CPUC Staff Report regarding the limited usefulness of effectiveness factors, the CAISO plans to only publish effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket. If stakeholders want additional effectiveness factor published, the CAISO will defer to the Commission as to what further effectiveness factor data it would like the CAISO to publish.

Definition of Effectiveness Factor

Effectiveness factor of a generator is calculated from the MW decrease is flow on the most limiting element (after the contingency has been taken) for a corresponding 100 MW increase in generation from that generator

Major Changes from last year's study

The introduction of Resource Adequacy Qualifying Capacity data

With the exception of the Bay Area study, the 2006 LCR Study utilized the historical output values of the available generation [based on the average generation output (between 2-5 pm) during the three hottest days in the summer] as the total dependable generation available. Given what the CAISO knows today, the historical output values utilized in the 2006 LCR study were lower when compared to the RA Qualifying Capacity data the CAISO utilized in the 2007 LCR Study. This difference was especially significant for areas with significant amounts of QF and hydro generation (i.e., Sierra and Humboldt). For the Bay Area study, the 2006 LCR study utilized the P max values which, when compared to the 2007 LCR study, were larger than the RA Qualifying Capacity data, especially due to QF and wind generation (see Bay Area study).

Total area requirement compared with sub-area requirements

The purpose of this report is to provide detailed local procurement information, as such each local area's overall requirement has to be procured in a fashion that satisfies all of the sub-area requirements as well.

The role of sub-area requirements:

Because each individual sub-area is a part of the interconnected electric system, the total for each local area is not simply a summation of the sub-area requirements (i.e., the sum of the parts does not necessarily equal the sum of the whole). For example, some sub-areas may overlap and therefore the same units can be counted toward both sub-area requirements. Of course some sub-areas requirements are directly counted toward the total requirements of a bigger local sub-area or the overall area. Other times the area has an overall requirement that exceeds the sum of the sub-area requirements. Each area is unique and detail analysis is provided in the report and each area's presentation.

Can an area have a higher LCR requirement then load?

Yes.

There should be no load drop for a category B condition. Take, for example, an area such as Sierra or Humboldt with has a limited import capability. Sierra has more ties, however some of them are exporting power therefore the net import is relatively small. Humboldt has few ties and 100% of the load must be served when one generator or a generator and a line are out of service. In both cases these contingencies (Rio Oso-Poe 230 kV with one of the Colgate units out or Cottonwood-Bridgeville with one of the Humboldt units out) account for the loss of ~25% of Qualifying Capacity in that area. One can see that if there were no ties the requirement would need to be at least 125% of load in the area.

This is particularly true for areas where deficiencies in some sub-area have been added to the total existing generation in order to come up with the Total Area Requirement.

Local load can NOT be subtracted from total LCR in order to come up with “Import Capability” into any one area. The LCR requirement represents the total “Capacity” needed in that area in order to respond to a large number of contingencies (including sub-area requirements). Not all of this capacity needs to be on-line simultaneously, some of it can be called upon after the first contingency has happened (especially in area with a lot of fast start units.

Zonal Requirements

The ISO performed an assessment of the Zonal Capacity needs for year 2007. These results refer to the ISO control area only, they do not include requirements for other control areas like: LADWP, IID, SMUD-WAPA, TID or MID. Units need in order to comply with the Local Area Capacity Requirements fully count toward the Zonal Requirements. San Diego and LA Basin are situated in SP26, Kern in ZP26 and the rest in NP15.

Zone	Load Forecast (MW)	Generator Outages (MW)	Single Worst Contingency (MW)	(-)Import Capability (MW)	Total Requirement (MW)
SP26	28,778	1,500	2,000	10,100	**22,178**
NP26=NP15+ZP26	21,518	2,500	1,160	5,348	**19,830**
NP15	Path 15 is not a binding constraint at this time				

Load forecast = 1-in-5

Generator outages = average historical data

Single worst contingency = ISO share of PDCI in the South, Diablo unit in the north

Import Capability = ISO maximum historical import capability

How do I read this table ?

	Qualifying Capacity			2007 LCR Requirement Based on Category B (Option 1)			2007 LCR Requirement Based on Category C with operating procedure (Option 2)			2006 Total LCR Req.
Local Area Name	**QF/ Muni (MW)**	**Market (MW)**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**Existing Capacity Needed**	**Deficiency**	**Total (MW)**	**(MW)**
Humboldt	73	133	206	202	0	**202**	202	0	**202**	162
North Coast / North Bay	158	861	1019	766**	0	**766****	766**	0	**766****	658
Sierra	1072	776	1848	1833	205	**2038**	1833	328	**2161**	1770*
Stockton	314	257	571	348	0	**348**	506	53	**559**	440*
Greater Bay	1314	5231	6545	4771	0	**4771**	5341	0	**5341**	6009
Greater Fresno	727	2185	2912	2760	0	**2760**	2797	4	**2797**	2837 *
Kern										797*
LA Basin	3425	7033	10458	8843	0	**8843**	8843	0	**8843**	8127
San Diego	191	2741	2933	2781	0	**2781**	2781	0	**2781**	2620
Total	**7274**	**19217**	**26492**	**22304**	**205**	**22509**	**23069**	**385**	**23450**	**23420**

* Generation deficient areas (or with sub-area that are deficient) – deficiency included in LCR
** The North Coast/North Bay area requirement would have been higher by 80 MW, however a new operating procedure has been received, validated and implemented by PG&E and the CAISO.

Table interpretation

Category C numbers are identical with Category B numbers

This area or sub-area requirement is driven by a Category B contingency, there is no Category C contingency with a higher requirement.

QF/Muni (MW) – Qualifying Capacity

Includes QF's, Self-gen, Muni, State, Federal, nuclear and Wind generation.

Existing Capacity Needed

This represents the amount of capacity needed to be procured from the existing units in the area.

Deficiency

This represents a proxy amount of extra capacity needed in order to comply with that category of the criteria by increasing the output of the most effective unit in the area (or sub-area) beyond it's qualifying capacity until the problem has been solved.

What does it mean to be deficient in one area?

Load drop needs to be implemented. For most category B contingencies there may be an existing scheme that drops load after the first contingency. For most category C contingencies the load most likely needs to be dropped at some reasonable time after the first contingency in order get the system into a safe operating zone and be able to support the loss of the next contingency and be within the existing applicable ratings.

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

APRIL 2005

Western Electricity Coordinating Council

APRIL 2005

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

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

Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

NERC/WECC PLANNING STANDARDS

Revised April 10, 2003

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.

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 common mode contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.***

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.*

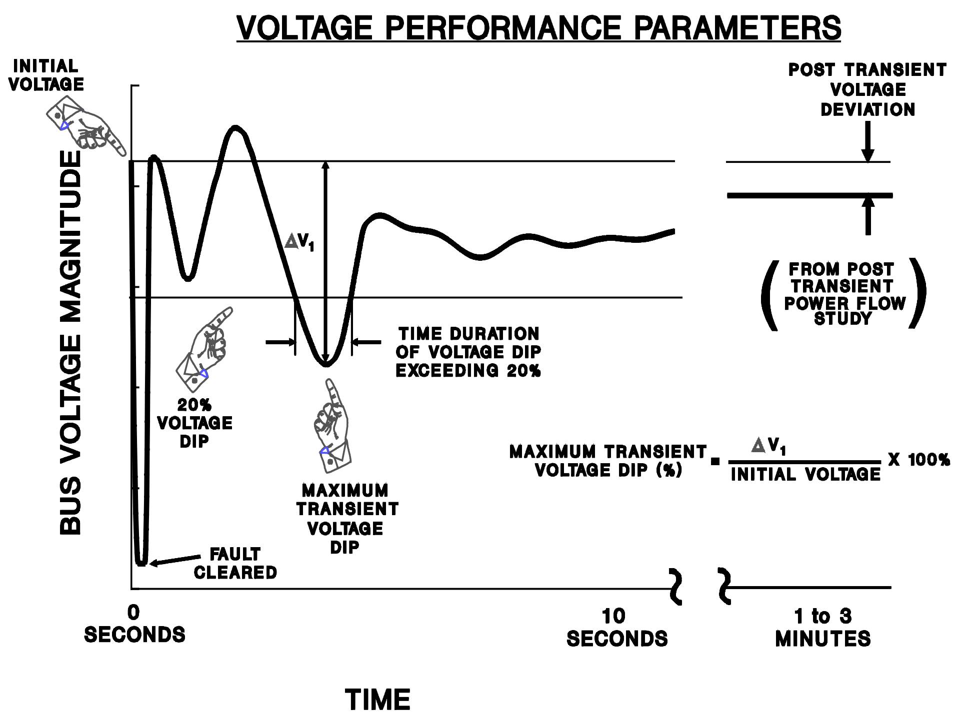


Figure W-1

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 the maintenance 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.***

WECC-G5 ***Considerations in determining the probability of occurrence of an outage of two adjacent circuits on separate towers should include line design; length; location, environmental factors; outage history; operational guidelines; and separation between circuits.***

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 3. Transformer 2. Transmission Circuit 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.

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 under-frequency 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**.

I.E Transfer Capability

1. NERC Transmission Transfer Capability Task Force, *Transmission Transfer Capability*, Reference Document, May 1995.

2. NERC Transmission Transfer Capability Task Force, *Available Transfer Capability Definitions and Determination*, Reference Document, June 1996.

II.A System Data

1. Multregional Modeling Working Group, *NERC Multregional Modeling Working Group Procedural Manual*, Revision No. 11, April 1997.

2. System Dynamics Database Working Group, NERC *System Dynamics Database Working Group Procedural Manual*, December 1996.

3. U.S. Department of Energy, Energy Information Administration, *Instructions for Electronic Reporting of Regional Electricity Supply & Demand Projections* (EIA-411), 1996.

III.B Transmission Control Devices

1. J. F. Hauer, "Robust Damping Controls for Large Power Systems," IEEE Control Systems Magazine, pp. 12–19, January 1989.

2. IEEE Special Stability Controls Working Group, +Static Var Compensator Models for Power Flow and Dynamic Performance Simulation, IEEE Transactions on Power Systems, Vol. 9, No. 1, pp. 229–240, February 1994.

3. CIGRE Task Force 14–07, "Interaction between DC and AC Systems," CIGRE, paper 14–09, 1986.

4. CIGRE Working Group 14.07, Guide for Planning DC Links Terminating at AC Systems Locations Having Low Short–Circuit Capacities, Brochure No. 68, June 1992.

5. CIGRE Task Force 38.05.05, Use of DC Converters for VAr Control, Brochure No. 82, August 1993.

References

6. CIGRE Task Force 38.01.07, CIGRE Technical Brochure on Control of Power stem Oscillations, 1997.

III.C Generation Control and Protection

1. P. Kundur, *Power System Stability and Control*, McGraw-Hill, 1994.

2. *IEEE Guide for Synchronous Generator Modeling Practices in Stability Analysis*, IEEE Std 110–1991.

3. *IEEE Guide for Identification, Testing and Evaluation of the Dynamic Performance of Excitation Control Systems*, IEEE Standard 421.2–1990.

4. *IEEE Recommended Practice for Excitation System Models for Power System Stability Studies*, IEEE Std 421.5–1992.

5. IEEE Digital Excitation Task Force, "Computer Models for Representation of Digital-Based Excitation Systems," *IEEE Transactions on Energy Conversion*, Vol. 11, No. 3, pp. 607–615, September 1996.

6. IEEE Excitation Limiters Task Force, "Recommended Models for Overexcitation Limiting Devices," *IEEE Transactions on Energy Conversion*, Vol. 10, No. 4, pp. 706–712, December 1995.

7. IEEE Excitation Limiters Task Force, "Underexcitation Limiter Models for Power System Stability Studies," *IEEE Transactions on Energy Conversion*, Vol. 10, No. 3, pp. 524–531, September 1995.

8. J. R. Ribeiro, "Minimum Excitation Limiter Effects on Generator Response to System Disturbances," *IEEE Transactions on Energy Conversion*, Vol. 6, No. 1, pp. 29–38, March 1991.

9. M. S. Baldwin and D. P. McFadden, "Power Systems Performance as Affected by Turbine-Generator Controls Response During Frequency Disturbances," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-100, No. 5, pp. 2486–2494, May 1981.

10. F. P. deMello, L. N. Hannett, and J. M. Undrill, "Practical Approaches to Supplementary Stabilizing from Accelerating Power," *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-97, pp. 1515–1522, September/October 1978.

11. CIGRE Task Force 38.01.07, CIGRE Technical Brochure on Control of Power System Oscillations, 1997.

References

12. *American National Standard for Rotating Electrical Machinery - Cylindrical-Rotor Synchronous Generators*, ANSI C50.13–1989. (Standard gives time-overload requirements for generator armature and field windings.)

13. IEEE Std. 122-1985, *IEEE Recommended Practice for Functional and Performance Characteristics of Control System for Steam Turbine-Generator Units*, IEEE, 1985.

14. EPIC Engineering, Inc., *Impacts of Governor Response Changes on the Security of North American Interconnections*, EPRI Final Report TR-101080, October 1992 (prepared for NERC and available to NERC members).

15. P. Kundur, “A Survey of Utility Experiences with Power Plant Response during Partial Load Rejections and System Disturbances,” *IEEE Transactions on Power Apparatus and Systems*, Vol. PAS-100, No. 5, pp. 2471-2475, May 1981.

16. P. B. Johnson, et al., “Maximizing the Reactive Capability of AEP Generating Units,” *Proceedings of American Power Conference*, April 1990.

17. M. M. Adibi and D. P. Milanicz, “Reactive Capability Limitation of Synchronous Machines,” *IEEE Transactions on Power Delivery*, Vol. 9, No. 1, pp. 29–40, February 1994.

18. N. E. Nilsson and J. Mercurio, “Synchronous Generator Capability Curve Testing and Evaluation,” *IEEE Transactions on Power Delivery*, Vol. 9, No. 1, pp. 414–424, January 1994.

19. A. Panvini and T. J. Yohn, “Field Assessment of Generators Reactive Capability,” *IEEE Transactions on Power Systems*, Vol. 10, No. 1, February 1995.

20. IEEE/PES Transformers Committee, *IEEE Guide for Transformers Directly Connected to Generators*, IEEE/ANSI Standard C57.116-1989. (Provides guidance on generator step-up transformer tap settings.)

21. CIGRÉ Task Force 38.02.17, *Criteria and Countermeasures for Voltage Collapse*, CIGRÉ Brochure No. 101, October 1995.

22. IEEE/PES Protective Relaying Committee, *IEEE Guide for Abnormal Frequency Protection for Power Generating Plants*, ANSI/IEEE Standard C37.106–1987 (currently under revision).

23. IEEE/PES Protective Relaying Committee, *IEEE Guide for AC Generator Protection*, IEEE Standard C37.102-1987.

References

III.D Underfrequency Load Shedding

1. D. W. Smaha, C. R. Rowland, and J. W. Pope, “Coordination of Load Conservation with Turbine-Generator Underfrequency Protection,” IEEE Transactions on Power Apparatus and Systems, Vol. PAS-99, No. 3, pp. 1137–1150, May/June 1980.

2. C. W. Taylor, F. R. Nassief, and R. L. Cresap, +Northwest Power Pool Transient Stability and Load Shedding Controls for Generation-Load Imbalances, IEEE actions on Power Apparatus and Systems, Vol. PAS-100, No. 7, pp. 3486–3495, July 1981.

3. K. L. Hicks, “Hybrid Load Shedding is Frequency Based,” IEEE Spectrum, pp. 52–56, February, 1983.

III.E Undervoltage Load Shedding

1. CIGRE Task Force 38.02.17, Criteria and Countermeasures for Voltage Collapse, CIGRE Brochure No. 101, October 1995.

2. C. W. Taylor, Power System Voltage Stability, McGraw-Hill, 1994 (Chapter 7 describes 1800 MW of undervoltage load shedding installed in the Puget Sound area).

3. IEEE Power System Relaying Committee Working Group K12, Voltage Collapse Mitigation, December 1996 (available for download from IEEE Power Engineering Society web site).

4. H. M. Shuh and J. R. Cowan, “Undervoltage Load Shedding-An Ultimate Application for the Voltage Collapse,” Proceedings of the Georgia Tech Protective Relay Conference, April 29–May 1, 1992.

III.F Special Protection Systems

1. Kundur, Power System Stability and Control, McGraw-Hill, 1994 (refer to Chapter 17, Methods of Improving Stability).

The NERC Planning Standards were approved by the NERC BOT 1997, 2001, 2002
Approved by Planning Coordination Committee June 29, 2001
Approved by Board of Trustees August 7, 2001
Revisions Approved by Planning Coordination Committee February 28, 2002
Revisions Approved by Board of Trustees April 18, 2002
Revisions Approved by Planning Coordination Committee June 27, 2002
Approved by Board of Directors August 9, 2002
Approved by Board of Directors April 10, 2003

WESTERN ELECTRICITY COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

PART II

Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

Revised April 18, 2002

WESTERN ELECTRICITY COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

TABLE OF CONTENTS

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
Approved by Board of Trustees August 8, 2000
Revised April 18, 2002

WESTERN ELECTRICITY COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

PART III

Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

MINIMUM OPERATING RELIABILITY CRITERIA

Revised April 6, 2005

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 Operations 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 Operations 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.** The frequency bias shall be set as close as possible to the control area's natural frequency response characteristic. *Refer to NERC Policy 1C for determining frequency bias setting* methodologies.

   a. **Frequency bias setting for control areas with native load.** In no case shall the annual fixed frequency bias or the monthly average variable 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.

   b. **Frequency bias setting for generation-only control areas.** At a minimum, the annual fixed frequency bias or the monthly average variable frequency bias shall be set at a value of the total generator droop setting from WECC MORC Section 1.C.2 per 0.1 hertz 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.

During disturbances, the primary objective is to minimize the magnitude and duration of load interruptions for the Western Interconnections. This may require load interruptions in local areas or controlled separation to avoid greater impacts to the Interconnection or to expedite restoration.

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 shall be kept in service to the maximum extent possible and shall be properly tuned in accordance with WECC requirements.

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 notify its Reliability Coordinator and 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, control area(s) shall initiate relief measures as required, up to and including shedding load, to maintain reserves as specified in Section 1.A.

2. **Deficient Resource Loss.**

   Following a resources loss greater than MSSC, or after failing to meet DCS, a control area shall immediately take the necessary steps to return ACE to zero:

   - load all available generating capacity, and
   - utilize all operating reserve, and
   - interrupt all interruptible load and interruptible exports, and
   - utilize fully all emergency assistance from other control areas, and
   - shed load.

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 <u>solid-state underfrequency relays</u>. 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. **Proximity of Backup Control Center to primary Control Center.** If the plan includes a backup control centers should be provided to prevent the outage of both facilities due to any credible threat including but not limited to the following:

   1) Natural disasters, such as:

      a. Earthquakes

      b. Floods

      c. Hurricanes

      d. Tornadoes

   2) Accidents, such as:

      a. Fire

      b. Internal environmental problems

      c. Chemical spills

      d. Plane crash

      e. Explosion

      f. Loss of communications, and

      g. Catastrophic event

3. **Communications.** Maintain basic voice communication capabilities with other control areas.

4. **Schedules.** Maintain the status of all interarea schedules such that there is an hourly accounting of all schedules.

5. **Critical interconnections.** Know the status of and be able to control all critical interconnection facilities.

6. **Tie line control.** Provide basic tie line control capability to avoid burdening neighboring control areas with excessive inadvertent interchange.

7. **Periodic tests.** Conduct periodic tests of backup and control functions to ensure they are in working order.

8. **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. **System Operator Training.** WECC operating entities shall provide a coordinated training program fro system operators in compliance with NERC Policy 8.B.

2. **Positions Requiring Trained System Operators.** MORC 8.C applies to any position requiring a NERC Certified System Operator.

3. **Continuing Education.** 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 and to ensure knowledge of and compliance with WECC criteria and procedures and NERC policies and standards.

   3.1 **Training Hours.** Operating personnel shall receive at least 10 hours of NERC-approved continuing education training in every two calendar-year period, which shall be specific to WECC MORC, procedures, and guidelines. Individuals who have attained WECC System Operator certification and whose certificate is not more than one year old may receive the equivalent of 10 hours of credit for passing the WECC certification examination.

   3.2 **Required Training Hours.** The training hours requirement in 3.1 above, must be met regardless of whether the system operator participates in the NERC continuing education program.

   3.3 **Training Programs.** Training programs may include attendance at training sponsored by WECC, Operating Entities, or other vendors of training, including in-house developed training, provided such programs are NERC Continuing Education Program approved. Students and operating entities shall ensure course content is compatible with the 10-hour specific WECC requirements.

   3.4 **Training Documentation.** Operating Entities shall maintain training documentation of operating personnel for at least three years, including but not limited to, the operator name, the number of NERC CE units earned, the date of the training, course title, and the NERC-approved course and/or provider ID number. All documentation shall be made available to WECC or a designated compliance monitoring review team upon request.

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 Operations Committee.

June 19, 1970
Revised November 3, 1981
Revised August 11, 1987
Revised March 7, 1989
Revised August 8, 1989
Revised November 14, 1989
Revised March 13, 1990
Revised March 10, 1992
Revised November 5, 1992
Revised March 8, 1994
Revised December 2, 1994
Revised March 11, 1997
Revised July 29, 1997
Revised August 11, 1998
Revised March 8, 1999
Revised August 8, 2000
Revised December 7, 2000
Revised March 28, 2001
Revised April 18, 2002
Revised August 9, 2002
Revised April 23, 2004
Revised December 3, 2004
Revised April 6, 2005

WESTERN ELECTRICITY COORDINATING COUNCIL

DEFINITIONS

Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

NERC/WECC PLANNING STANDARDS

AND

MINIMUM OPERATING RELIABILITY CRITERIA

DEFINITIONS

Revised August 9, 2002

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

Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

PROCESS FOR DEVELOPING AND APPROVING WECC STANDARDS

Revised August 23, 2002

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

[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

---

[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.

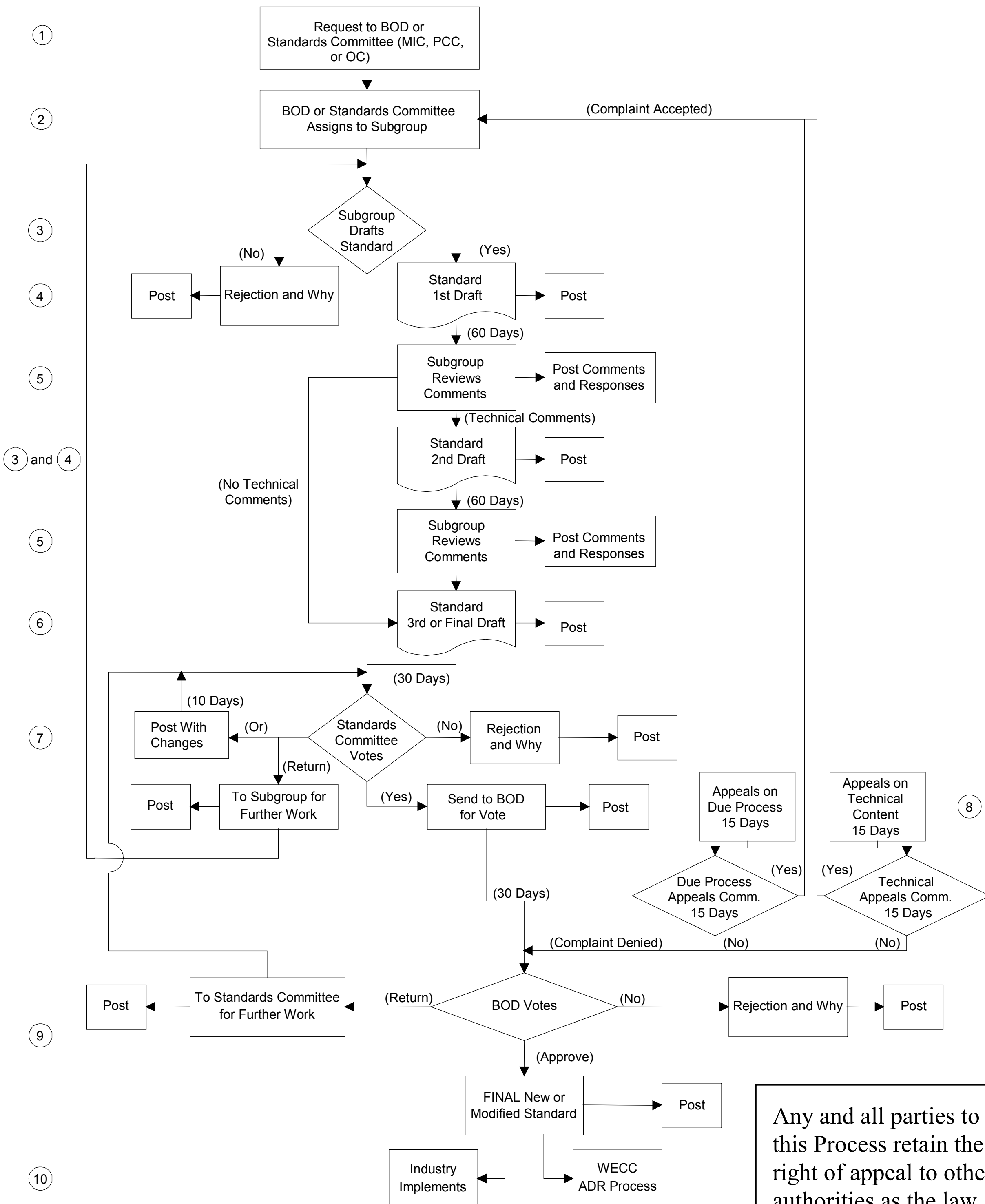
A majority vote of the Directors present at a Board meeting, as specified in Section 7.2 of the WECC Bylaws, is required to approve the recommended Standard.

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.

Meeting Summary - LCR Study Advisory Group (LSAG)
September 28, 2006, ISO Offices in Folsom

Introductions

On September 28, 2006 the inaugural meeting of the LSAG was held. Those in attendance are listed in Attachment 1. A package of reference material was available for the group. This material is also included in Attachment 1.

The meeting was opened with introductions. It was noted that two additional representatives from the generator community would be added to the group. The names of these individuals were unknown at the time of the meeting. The agenda was reviewed and no changes were made.

The purpose, representation, expectations, and objectives of the group were discussed. The CAISO explained that the group was intended to provide a representative cross-section of stakeholders that were technically qualified to assess the CAISO's LCR study assumptions, criteria, and methodology in preparation for the 2008 LCR study. The CPUC schedule for 2008 LCR results will require the CAISO to initiate the 2008 analysis in January 2008. The LSAG is to review and evaluate the technical components of the LCR study and recommend changes, where needed, that could be implemented into the 2008 study. Members requested assurance that the focus would remain technical and that the LSAG recommendations would not circumvent all stakeholders having the opportunity to review the LSAG recommendations. The CAISO stated that the group's only focus is technical issues and that follow-up stakeholder review of the LSAG's findings and/or recommendations is the forum for determining the final LCR study assumptions, criteria and methodology.

The CAISO stated that the LSAG's first task is to provide a technical review of how the CAISO performed the 2007 LCR study. Specifically, the LSAG is being asked to consider whether or not the results the CAISO documented in its 2007 LCR study report reflect the study assumptions (load, generation dispatch, transmission configuration) the CAISO used;

- given the results of the power flow analysis (flows, currents, voltages, etc.) are directly related to the study assumptions and;
- given how the CAISO applied the NERC/WECC planning standards to the results.

The CAISO did not ask the LSAG to agree or disagree with the LCR recommendations provided to the CPUC; rather, CAISO asked, "Given how the CAISO performed the study, were the CAISO answers reflective of the technical data and calculations used?" The CAISO stated that work on the 2008 LCR study could not move forward until the LSAG had reached a consensus that the CAISO's 2007 study results are "technically" factual. Some felt that the focus of the LSAG should be looking to the future for the 2008 LCR studies, however others agreed that going over the study steps and assumptions used in 2007 was needed to move on to discussion of methodology for the 2008 LCR Study. Establishing these "technical" facts will focus and facilitate discussion on technical issues for the 2008 analysis.

General Comments from the LSAG

- Clarity about the LSAG objectives and the steps that will be taken after the LSAG group completes its work is needed;
- It is important to have the right proportion of people in the group to represent the broader stakeholder population;

- Cannot get too caught up in whether people in the group agree or disagree; the larger stakeholder community should decide. It was reiterated that the LSAG is a technical group not a “stakeholder” process;
- Main issues that should be addressed first are (1) Deliverability issues (2) Clarify how consistency between the CEC load forecast and the load level used in these studies was achieved; (3) Transparency of operation procedures needed;
- There is a need to technically validate the 2007 study. A more elaborate and detailed explanation of the 2007 study assumptions, methodology, and criteria would help LSAG members better understand and assess how the CAISO came up with the results;
- Reflected in the CAISO LCR methodology used included protection for all deliverable units (In the 2007 LCR Study the CAISO used the same levels of generation from the units that were determined to be deliverable in the deliverability study which used Category B and C5 contingencies to determine generation deliverability) because the flow pattern can change, depending on contractual arrangements both within and outside of California;
- Concerned that the imports have been set only at the allocated OTC and not full path ratings. Also concerned about retiring any units without the express consent of the facility owner;
- Who will be doing the Stakeholder process, ISO or CPUC?;*(Comment: the CAISO will conduct the effort to engage the larger stakeholder community. The CAISO is not aware of how the CPUC will proceed)*
- Please clarify what the next steps will be; *(Comment: the CAISO will work with the LSAG to better clarify the next steps from today through 2009)*;
- Manuals (tables, data) must be completed when the studies are done so that Stakeholders will have ample opportunity to review materials;
- Some members did not want to go through the 2007 details; believed that with CPUC adoption, the issue was moot; wanted to concentrate on 2008, without going through the 2007 studies;
- Some explanation on the security constrained least cost optimum power flow solution (SCOPF) that the CAISO will be using during MRTU and proposed that we use the same or very similar in our studies to determine the minimum LCR need in a certain local area. This software will automatically dispatch the system such that the next set of about 150 to 200 N-1 contingencies will be mitigated if they were to happen in the future. LSAG would discuss this methodology approach later.

<u>2007 LCR Study Review</u>

- CAISO described FERC’s LGIP process, which determines resource deliverability and the CPUC’s RA requirements, which set forth the system RA requirements of 115% to 117% of peak load and the local RA requirements (within the system RA requirements), as well as FERC indication that CAISO must meet all it’s needs with only units under RA contract, since in a not too distant future, those will be the only units obligated to respond to CAISO calls under Must-Offer. CAISO’s practices related to local area maintenance and continued by describing the input assumptions into the base cases and how they were achieved were also described;
- Explained how local area pockets have been defined and why;
- Explained the methodology used to arrive at the criteria category B and C contingencies;
- Explained how the CAISO addresses “real-time” contingencies and that the CAISO must plan and operate the system in accordance with the NERC/WECC Planning Standards. The CAISO must to be able to support all category B and C5 contingencies 100% of the time (meaning that after these first set of Category B and common mode N-2 contingencies all elements have to be within their respective

applicable ratings. In all NERC C Category contingencies, load shedding is an option as long as it is done in a planned and controlled manner).

- Further explained that the category C3 requirements or N-1-1 have to be protected immediately after the first B contingency in order to make sure the system can support the second contingency and be within applicable ratings. In all NERC C Category contingencies including C3, load shedding is an option only after the second N-1 has occurred as long as it is done in a planned and controlled manner. Therefore the category C requirements (to protect against the next N-1) that the CAISO established in the 2007 studies actually need to be met before the second contingency happened in order to assure that all facilities are within their Applicable Ratings after the second contingency. CAISO noted that its 2007 LCR Study did not ask for any additional requirements that need to be maintained after the second of N-1-1 contingency have happened (when load drop is allowed). It was pointed out that the N-1-1 is no different from N-2 if there is no time available for a "manual" system adjustment between the first event and when the second event actually occurs. However, if there is "time" between the first and second contingencies, which is more common than not in operations, this time can be used to adjust the system between outages. As such, an N-1-1 (over-lapping outages) is not the same as an N-2 (simultaneous outage). N-1-1 is codified in Category C.3 in Table 1 of the NERC/WECC Planning Standards. After the first N-1, loading on all facilities must be within their emergency ratings, among other performance requirements, and load shedding is not allowed. The facility loadings can stay above the normal ratings, but below emergency ratings up to the time duration the emergency ratings are applicable. Where applicable, after a readjustment time period, system operators must decrease all loadings to levels where the system returns to a safe operating zone in preparation for the next worst N-1, which can be any facility in the system. After the next (second) N-1, load shedding is allowed to bring the loadings to within the facilities emergency ratings as long as it is done in a planned and controlled manner. N-2 is simultaneous common-mode outages. After the N-2 common mode contingency, load shedding is allowed to bring the loadings to within the facilities emergency ratings as long as it is done in a planned and controlled manner. There will not be the extra requirement to adjust the system in preparation of the next worst N-1. The above description also applies to other performance requirements in addition to facility loadings;
- Of key concern among the group is that any operational practices used in the LCR studies should be transparent and they should be included in the base case. In addition, all base cases should be made available to all with a WECC membership. Others should sign a confidentiality agreement to get these cases.

Issues Raised

- Many group members were interested in the CAISO's approach on protection of full deliverability for units that have been already deemed deliverable through other proceedings (and studies) before single and category C5 contingencies. It was also noted that generation levels for individual generators within the generation pockets identified in the deliverability studies were set higher than historical values. In an area that has both a generation pocket and a load pocket, setting high levels of generation in the generation pocket could cause the LCR to increase in the load pocket in order to mitigate a potential congestion (deliverability) problem, which could have been avoided had the generation been set at historical (lower) levels. Consideration of impact on real time operations is necessary if historical patterns changes due to new market or contract situations. This issue was identified for more discussion by LSAG.;
- Interested in investigating seasonal studies in order to reduce LCR requirements in other then the summer season.; This is also one of CPUC's objectives;

- Imports and how they are accounted for in the study;
- Using low probability events (NERC/WECC Category C) is considered to stringent to establish LCR requirements;
- Description of the CEC load forecast for the entire state (CPUC and Non-CPUC jurisdictional entities) was provided. More discussion was suggested at the next meeting;
- Adding new transmission infrastructure should not increase load pocket areas. This issue was identified for more discussion by LSAG.

Parked Items (text as written on the flip chart)

- Protection of deliverability of units outside the bubble and how to dispatch generation outside the bubble to get inside the bubble *("for category B and C5 contingencies" - clarification text provided through LSAG comment)*;
- Load migration issue – annual showing – leaves capacity "stranded";
- Expanding load pockets due to additional transmission;
- Determine how CEC develops load forecast;
- Transparency of Operations Procedures needed.

Overall Conclusions Reached

- The CAISO explained the methodology of the 2007 LCR study. The Group indicated that there was a better understanding of how CAISO derived the results of the study, however, not everyone was willing to agree that CAISO's 2007 LCR results were "technically" consistent with how the CAISO performed the study. This will be discussed further at the next meeting.
- There was an extended discussion on the N-1-1 disturbance and that there is unanimous agreement that no load tripping is allowed after the first Category B event. This is clearly covered in the NERC Category B performance allowance. There was also unanimous agreement that load shedding is allowed after the second N-1 and that when the operators adjust the system to return to within a safe operating zone in preparation for the next worst N-1, no load shedding is allowed before the second N-1;
- Two key technical issues were identified for resolution: protection of deliverability of generation located outside a load pocket (this is a methodology issue) and expanding load pockets (this is a study assumption issue)

Other Items To Be Discussed In Future Meetings

- Discussion of alternative "methodologies" for determining LCR. Alternatives can be discussed across a longer term time period.
- Requested discussion of criteria used for SCE's LA Basin load pocket N-1, followed by N-2 on South of Lugo – Believed to be well beyond NERC requirements vs. N-1 system readjustment and stay within an approved path rating – well within the CAISO/WECC/NERC standards.

Next Meeting

October 20, 2006 at the CAISO