NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reactive Support and Control Whitepaper

TIS - Reactive Support and Control Subteam

(May 18, 2009)

to ensure the reliability of the bulk power system

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Preface

NERC Standards – Projects related to Voltage Control

NERC gratefully acknowledges the support of many teams and subcommittees who are working on improving standards related to voltage and reactive control. This report supports *Project 2008-01 Voltage and Reactive Control* which relates to Standards VAR-001-1a and VAR-002-1a.

Other teams are working on projects related to voltage and reactive control:

- *Project 2007-09 Generator Verification* includes reactive control related standards;
  MOD-025-1 – Verification of Generator Gross and Net Reactive Power Capability and
  MOD-026-1 – Verification of Models and Data for Generator Excitation System Functions.
- *Project 2007-17 Protection System Maintenance and Testing* includes voltage control related standards;
  PRC-011-0 – Under Voltage Load Shedding System Maintenance and Testing.
- *Project 2008-02 Under voltage Load Shedding* includes voltage control related standards;
  PRC-10-0 –Assessment of the Design and Effectiveness of UVLS Program and
  PRC-022-1 – Under voltage Load Shedding Program Performance.
- *Project 2009-02 Real-time Tools* includes several voltage and reactive control related standards including but not limited to;
  EOP-003-1 – Load Shedding Plans,
  IRO-004-1 –Reliability Coordination – Operations Planning,
  TOP-002-2 -- Normal Operations Planning,
  TOP-006-1 – Monitoring System Conditions, and
  VAR-001-1a – Voltage and Reactive Control

The above body of work is extensive and represents a concerted effort to carefully address issues and recommendations from several sources. These sources include but are not limited to: prior blackout report recommendations, FERC Order 693 directives, and industry comments related to reactive support and voltage control. NERC fully appreciates the industry expertise and extensive effort to improve the Standards, and more importantly provide continuous improvement of bulk electric system reliability.

1 Executive Summary

1.1 Documented Requirements

1.1.1 Criteria Requirements

Reactive power planning and operational techniques vary across the United States and Canada. In some areas voltage is a major concern and requires extensive study, while in other areas voltage problems rarely arise. However, in all cases the planning and operational techniques should be well documented and made available to those functional entities which have a reliability role within an interconnection.

The VAR Standards should require documented protocols and expectations to be established among key functional entities. Planning Coordinators (PC)[1] and associated Transmission Planners (TPs) should have a set of documented protocols regarding expectations among the functional entities[2] within the associated Transmission Owner (TO) footprints. Explicit reactive planning criteria may be combined with other planning criteria. However, every logical group of PC/TPs should have coordinated documentation. The PC/TP reactive planning documentation should be reviewed and updated periodically with input from best practices of other PC/TPs.

As described in FERC Order 693 directives[3] the planning document must include detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins (i.e. voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. The document must have requirements that clearly define what voltage limits are used and how much reactive resources are needed to ensure voltage instability will not occur under normal and emergency conditions.

Because reactive power needs vary significantly based on system characteristics and since the vast majority of reactive power must be supplied locally, it is not appropriate to establish a NERC wide reactive reserve requirement. The local supply and reactive power requirements must be analyzed and documented on a more local level, possibly

[1] The existing VAR standards use the term "Planning Authority (PA)". The Planning Authority was renamed "Planning Coordinator" (PC) in the Functional Model dated February 13, 2007. This is a name change only - there is no difference in their responsibilities. We will use the PC terminology in this report. As defined in this report a coherent set of reactive power Transmission Planners and Planning Coordinators will be called a "Transmission Planning Reactive Cluster (TPRC).

[2] A "functional entity" is an entity that meets the requirements of a particular function type (e.g., Reliability Coordinator, Planning Coordinator) and is required to register with NERC for inclusion in the NERC Compliance Registry (as defined by NERC's posted criteria). Registered functional entities are subject to the requirements of NERC's standards that apply to their function type. The abbreviation for each 'functional entity are defined in the *Statement of Compliance Registry Criteria (Revision 5.0)*

[3] See attached Appendix 1, FERC Order 693 directives; paragraphs 1861-1863, 1868-1871, 1875 & 1880.

consisting of an area the size of a TP or smaller, up to a Reliability Coordinator footprint or a logical cluster of multiple PC/TPs. For purposes of this report, this electrically nearby group of PC/TPs and their associated functional entities will be called a "Transmission Planning Reactive Cluster" (TPRC). As part of the required documentation set for a TPRC, the TPRC coordinators must include criteria to determine the appropriate TPRC area for consideration. Later in this report such an example criteria is provided. However, this example is one of many examples which may be coordinated and adopted by multiple PC/TPs within a given TPRC area. Based on the area's characteristics, these TRPC areas would likely have differing detailed criteria and requirements for static and dynamic reactive support.

1.1.2 Implementation Plan

In addition to reactive planning criteria documentation, a second set of implementation planning documentation is needed. Multiple TRPCs should review and coordinate plans by the functional entities involved in each system state (see Section 5). This includes functional entity local plans for reactive support and control to maintain local system reliability and avoid permanent damage to equipment. GO and GOP functional entities (see APPENDIX 3 for a list of abbreviations) may have no expansion plans within a 5 year planning horizon. However, such forecasts of no expansion or no reactive capability changes within 5 years must be made known to each TRPC. Collectively within a region multiple TRPCs need to coordinate documentation of an integrated multi-year reactive support and control plan.

The development of both sets of planning documents should be transparent to those functional entities that have a reliability role within the region. The final documents should be made available within reasonable written notice. Both the TPRC criteria documentation and the implementation plan documentation should be VAR Standard mandatory Requirements.

1.2 Functional Entities Involved in each System State Time Frame

Reactive support and control involves numerous functional entities. However, bulk reactive power cannot be transmitted as far as real power (see Appendix 4, Examples 1, 2, and 3). Therefore, the functional entities which need to plan, operate, and control reactive power are more localized and close coordination is required. As discussed in detail in Section 5 of this report, numerous existing Standards name many of the functional entities involved but explicit reactive support and control requirements are often not clear, and not well coordinated within the existing Standards. This has led to a variety of implicit understanding of what needs to be done, and resulted in gaps in the Standards regarding which functional entities should be involved in the analysis, planning, and operation of reactive support and control. Section 5 provides a basis for future Standard drafting teams to coordinate the role of functional entities. It also provides a road map of which functional entities need to be involved in each system state time frame. For this purpose the time frames are defined in Section 4. The VAR Standards should be the main vehicle for explicit Requirements regarding reactive support and control. Over time the existing Standards will reference the VAR Standards as needed to maintain clarity and consistency of the Requirements. This is a multi-year effort, but at this point in time the main effort should be to improve the VAR Standards.

1.3 Implementation Examples

This report describes what topics must be covered in the criteria documentation, and what topics must be covered in the implementation plan documentation. How it must be done is not specified in this report. However, the subteam recognizes the benefit of providing some examples of how it may be done. In Section 8 and its associated Appendices, several examples are presented. The subteam does not mean to imply that these are how it must be done. These examples are merely presented to show the feasibility on how it may be done. At this point in time official guidelines are not being presented. The Standards Drafting team will have the opportunity to prepare the draft VAR Standards stating what must be covered in the Requirements, and input from the various stakeholder sectors will provide further comments and examples. After these comments and examples are reviewed the Standards Drafting team may decide if one or more official guidelines should be prepared.

1.4 Next Step
Standards Authorization Request (SAR) Review and Approval

This whitepaper provides the reliability concepts and foundation for the SAR and subsequent work by the Standards development team and includes the directives contained in FERC Order 693 (Appendices 1 and 2). Appendices 1and 2 also include a brief list of previous Version 0 and Phase III/IV industry comments. In the third quarter of 2009 it is anticipated that a Standards development team will be named to proceed with Version 2 of Standards VAR-001-1a, *Voltage and Reactive Control;* and VAR-002-1a *Generator Operation for Maintaining Network Voltage Schedules.* The SAR will use this report as the main resource to develop Version 2 of the VAR Standards. Final completion of the revised VAR Standards is expected by fourth quarter of 2011.

As Project 2008-1 progresses to modify the VAR Standards, other related Standards and the NERC *Glossary of Terms Used in Reliability Standards (Glossary)* will need to be reviewed and updated for consistency with Version 2 of the VAR Standards. The creation of new SARs for other Standards may cause work to overlap with Project 2008-1. However, the VAR Standards should contain all the necessary explicit Requirements and reference other existing Standard requirements as appropriate.   Explicit reactive energy related Requirements should not be duplicated in other Standards. However, during the overlapping SAR work, such duplication may occur until the other related Standards and NERC *Glossary* are updated for consistency with VAR Standards Version 2.

2 Introduction

2.1 Whitepaper Report Scope:

In August 2008 the Transmission Issues Subcommittee formed the Reactive Support/Control Subteam (RSCS) to develop a report (whitepaper) to address the fundamental issues of Standards Committee Project 2008-01. This report identifies what technical requirements are needed to determine the reactive resources required under different system states. The report identifies what criteria and associated rationale are required to be documented to determine the split of dynamic reactive supply (such as reactive power provided by the generators and other dynamic devices) and static reactive power supply (such as static capacitors and other static devices). The report also identifies what criteria must be documented for distribution of the Interconnection's reactive resource needs among transmission, distribution, and generation facilities. The fundamental concepts in this report will also be used to develop a chapter for the Reliability Concepts document.

2.2 Project 2008-01 Voltage and Reactive Control

Brief Description *(rev. 8/2008)*

Standards Committee Project 2008-01 supports Blackout Recommendation 7a. Industry debate is needed on whether there should be a North American standard that requires a specific amount of reserves, or whether requirements for specific reserves should continue to be addressed at the regional level. The requirements in the existing standards need to be upgraded to be more specific in defining voltage and reactive power schedules. Consideration should be given to adding a requirement for the Reliability Coordinator to monitor and take action if reactive power falls outside identified limits. The project will incorporate the interpretation of VAR-002 Requirement 1 and Requirement 2. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

This report addresses each of the above issues.

3 Reactive Support and Control -– Physical Properties

3.1 Reactive Energy Conservation

A variety of reactive power producing equipment exists. As noted below in Section 3.4 and 3.5 they can generally be broken down into two categories; Dynamic Resources and Static Resources. The scope of this report does not cover the various physical equipment types within these categories. However, a physical description can be found in FERC staff report Docket# AD05-1-000. (See Chapter 2 – Physical Characteristics and Costs of Reactive Power in AC Systems.)

The physical laws of Reactive Energy Conservation cannot be broken. Each of the four separate Interconnections within NERC operates every moment of every day at unity Power Factor. In other words, Interconnection total customer reactive demand plus total system reactive losses must equal reactive power supply. Reactive power cannot be imported over Interconnection asynchronous DC tie lines. The Interconnection total production of reactive power must equal customer demand plus losses. If a production shortage occurs, voltage will immediately decline until customer demand plus losses decreases to match supply. Small production shortages will result in small degradation of grid voltage. Larger production shortages lead to severe low voltage or collapse. Severe low customer voltage may also result in motor protection operation and resulting equipment outages due to high motor currents caused by low voltage. More information on this topic can be found in Appendix 4 -- Reactive Support and Control Basics presentation. (See slide 8 to 14 and Example A slide 18 to 26.)

3.2 Reactive Energy Transmission Capability

Reactive energy cannot be transmitted as far as real energy. This is primarily due to bulk electric system transmission line impedances which have a naturally large X to R ratio. Transmission lines with large diameter conductors and resulting low resistance typically have an X to R ratio in the range of 5 to 25 (see Appendix 4 slide #15).

It is recognized that high voltage transmission lines greater than 200kV are a local source of shunt reactive energy (line charging). This local reactive energy source is similar to a fixed static capacitor connected to each end of the line. This has the same effect as static capacitors connected to the line's substation bus. Such line charging is one more local source of static reactive energy. However, reactive losses on heavily loaded transmission lines often exceed the local static reactive energy produced by line charging. Large X to R ratios produce a significant difference in MW losses compared to Mvar losses. Depending on the transmission line fixed attributes such as conductor spacing and diameter of the conductor, the X to R ratio can typically vary from 5 to 25. Therefore, Mvar losses are typically 5 to 25 times higher than MW losses depending on the transmission line's X to R ratio.

Compared to MW real energy transmission, larger voltage drops occur if Mvars are transmitted across transmission facilities which have a large X to R ratio. When sufficient local reactive energy sources are not provided, large voltage drops will occur. See Appendix 4 Examples 1, 2, and 3. The physical laws (equations) show the comparison. When 300MWs are transmitted across the 230kv line (Example 1), the voltage magnitude change is 2.4%. Instead, as shown in Example 2, if 300 Mvars are transmitted across the line, the voltage change is 13%. If the transmission line reactance, X, was magically reduced to equal R (X to R ratio=1), the same approximate voltage drop would occur when transmitting Mvars compared to an equal amount of MWs. In other words, as shown by the Appendix 4 simplified equations, due to large X to R ratios transmitting Mvars across a transmission line produces voltage drops in the range of 5 to 25 times higher than transmitting an equal amount MWs.

Long distance systems, with their inherently larger transfer reactance, X, cannot transmit as many Mvars compared to systems which have a lower transfer reactance. All of these physical attributes result in the need for reactive energy to be supplied by local reactive energy sources to meet customer reactive energy demand plus system reactive losses.

3.3 Tap Changing Automatic Voltage Regulators

Transformer automatic tap changers and distribution voltage regulators do not produce reactive energy, but can pull and push vars toward customer load. A “boost tap change” pulls vars from system source side and pushes vars toward load.

If sufficient reactive energy resources exist at a remote source, a local “boost tap change” will decrease the regulator source side voltage and vars will flow from the remote source to the local regulator. The additional vars and tap change result in a load side voltage increase. If the regulator load side voltage is still below schedule, additional boost tap changes will occur. To maintain scheduled voltage the tap changer may significantly lower the source side voltage even for a very small increase in load.

If additional reactive energy resources do NOT exist, reactive energy supply will not increase. The automatic tap changer will ‘boost’ to the high limit tap in an attempt to maintain load side scheduled voltage. The source side voltage may collapse. The above behavior can be modeled only if adequate data is documented and made available. The above can be predicted only if reactive forecasts and models are provided by all the functional entities involved (GOs, TOs, DPs, LSEs, PSEs, etc).

See Example A, slides 19 to 26 in APPENDIX 4: Reactive Support and Control Basics. The generator reactive energy output must not exceed the generator rating for a long period of time. In Example A, as shown on slide 23, the generator Mvar output is exceeding its rating. The GOP must take action to prevent permanent damage to the generator rotor. As shown on slide 24, after GOP return to Mvar rated output, the generator cannot maintain scheduled voltage of 103.5%. The system voltage drops to 92% and the distribution customer voltage collapses to 88%. The TOP or DP must then shed firm customer load to prevent customer permanent equipment damage. As shown by Example A, the voltage collapse was not caused by higher MW load transfers. The voltage collapse was caused by lack of adequate reactive source total capability to meet distribution customer increased reactive demand plus system reactive losses.

Conservation of reactive energy is very important to avoid a voltage collapse. The total reactive supply must meet total load reactive demand plus reactive losses. Where applicable, Demand Side Management (DSM) for non-firm loads may be used to reduce the real and reactive demand, thus reducing the associated reactive system losses. However, as shown in Example A, if reactive sources cannot meet customer firm reactive demand plus system reactive losses, the system and customer voltage will drop (or collapse) until the customer demand drops to the point where reactive demand plus reactive losses matches the resource total available reactive output. The physical laws of conservation of reactive energy cannot be broken.

3.4 Dynamic Resources

Generators, static var compensators (SVCs), static compensators (STATCOMs), other Flexible AC Transmission Systems (FACTS) and synchronous condensers provide dynamic reactive power. However, under substation low voltage conditions, static capacitors used in devices such as SVCs do not produce maximum reactive power as reliably as dynamic self excited power equipment because capacitor reactive power output depends on substation voltage. Capacitor reactive power output changes in proportion to the square of voltage magnitude. For example if substation voltage declines from 100% to 90% of nominal voltage, static reactive power output declines from 100% of capability to 81%.

Dynamic reactive resources are typically used to adapt to rapidly changing conditions on the transmission system, such as sudden loss of generators or transmission facilities. In contrast as noted below in Section 3.5, switched static devices are typically used to adapt to slowly changing system conditions.

Generators have differing abilities to provide Vars depending on a number of factors such as; stator ampere rating, exciter system DC field current rating, AC terminal high voltage limit, actual MW output of the prime mover compared to generator rated power factor original design, control system variations, equipment changes due to age, etc.

An appropriate combination of both static and dynamic resources is needed to ensure reliable operation of the transmission system.

3.5 Static Resources

Switched Static Automatic Control

Switched devices are typically used to adapt to slowly changing system conditions such as daily and seasonal load cycles and changes to scheduled transactions. Static capacitor resources typically have lower capital cost than dynamic devices, and from a systems point of view, static capacitors are used to provide normal or intact-system voltage support. Often it is possible to locate static capacitors near to reactive load, increasing their effectiveness. By contrast, dynamic reactive resources are used to adapt to rapidly changing conditions on the transmission system, such as sudden loss of generators or transmission facilities. Coordinated planning criteria, and 5 year implementation plans are required among GOs, TOs, and DPs to provide the appropriate mixture of local automatic control. Each TPRC should have such documentation.

Switched Static Manual Control

In many cases local automatic control of switched static reactive resources is not appropriate. TOP manual control and centralized dispatch is appropriate. Each TPRC should coordinate with their TOPs and associated RCs on the need for centralized dispatch, control modification plans and implementation requirements.

Fixed Static Reactive

Transmission system 200kV and above overhead lines provide a significant source of shunt reactive ‘charging current’. Such ‘charging current’ is an excellent source of fixed static reactive similar to substation shunt capacitors. Likewise, high voltage transmission cable provides an excellent source of fixed static reactive. On lightly loaded transmission lines and cables the reactive losses may be very low due to the low ampere current. Under such lightly loaded conditions (below surge impendence loading) the fixed static reactive ‘line charging’ may far exceed the reactive losses. In such cases careful coordinated planning is required to avoid substation equipment high voltage. The plan may require fixed or switched shunt inductors, SVCs, or operational plans to switch lightly loaded transmission lines out of service. Each 5 year plan for the functional entities within the TPRC requires a coordinated mixture of Fixed, Switched, and Dynamic reactive resources.

4 System State Analysis Time Frames

Reactive support and control system requirements can be best understood by sub-dividing system state time frames for analysis. For purposes of this report four time frames are identified below:

4.1 Time Zero (Normal Steady State prior to contingency failure)

This steady state power flow system condition includes the results of all manual readjustments and automatic device responses that occurred up to this point to either return the system to Normal operation, after a contingency event, or to prepare for a routine day of system operation with all facilities initially in-service or out of service on planned maintenance. Under this state there would be no Normal limit violations, and the precontingency analytical results would show no Emergency limit violations, and no other violations of operating or planning Standards

4.2 Zero to 3 Seconds (Transient natural swings during contingency failure)

This first three seconds of dynamic stability analysis includes all automatic device responses within this time frame. Such as generator automatic voltage regulator (AVR) initial over excitation system response (if any), DC field initial response, governor, turbine and all other fast automatic controls which respond within 3 seconds. For this analysis do not include automatic tap changer movement or other controls which have slow response or intentional time delays.

4.3 3 to 30 seconds (Post Transient – Dynamic analysis)

This dynamic stability analysis includes all automatic device responses within this time frame, such as dynamic control analysis of AVR, governor, prime mover, and all other continuous/fast automatic controls which respond within 3 sec to 30 seconds. Automatic tap changers and other controls which have intentional time delays are recognized and modeled appropriately based on their delayed response. For this analysis do not include slower manual controls such as manual tap changing under load, manual capacitor switching, or other operations requiring more than 30 seconds.

4.4 30 seconds to 3 minutes (Post Transient - Load Flow analysis)

This steady state power flow analysis includes the results of all automatic device responses that occurred within 3 minutes, such as exciter system response to maintain automatic control set points (voltage schedule, or power factor, etc). It includes governor and prime mover MW response and all other continuous automatic controls which respond within 30 seconds to 3 minutes. Automatic tap changers and other controls which have intentional time delays are recognized and modeled appropriately. For this analysis do not include manual controls such as manual tap changing under load, manual capacitor switching, etc.

4.5 3 minutes to 30 minutes or applicable short time emergency rating time frame

(Emergency Steady State readjustments)

This steady state power flow analysis includes the results of all manual readjustments and automatic device responses that occurred within 30 minutes, such as TOP and GOP re-dispatch to get ready for the next event. It includes applicable automatic and manual non-continuous/slow controls such as manual tap changing under load, manual capacitor switching, etc.

5 Functional Entities Involved in Each System State

5.1 Progression from Five-Year Plan to Implementation

A review of existing Standards shows a wide variety of reactive related Requirements. See APPENDIX 5: Reactive Related Standards. The 'Existing Requirements' tab in the work book shows the functional entities presently involved by system state analysis time frame, and provides the related standard Requirement paragraph numbers. Many of these Requirements have an implicit relationship with reactive support and control; however, some of the Requirement paragraphs explicitly state the need for reactive source data, etc. The 'Desired Coverage' tab in the workbook, shows the coverage by functional entities which are typically needed in each system state analysis time frame. A comparison of these two spreadsheets shows there are gaps in the Existing Requirements compared to Desired Coverage by the functional entities.

5.1.1 Entities involved for 5 year plan

As noted on the desired coverage spreadsheet, within the 5 year planning horizon, numerous functional entities need to be involved to either provide data, forecast changes to reactive demand, provide changes to previous plans, and / or propose changes to reactive sources, controls, etc. The primary entities involved are TOs, TPs, TOPs, GOs, GOPs, RPs, DPs, LSEs, PSEs, and PC coordinators.

5.1.2 Entities involved for 1 year plan

Within the 1 year planning horizon, the burden shifts to nearer term implementation of as built system facilities. Based on actual facilities installed and associated reactive performance data, the primary planning involves TOPs, GOPs, and RCs with significant coordination from PCs, TPs, and DPs, LSEs, PSEs for updated contracts, revised reactive demand expectations, changes to Demand Side Management, etc.

5.1.3 Entities involved for Operations Planning

Within the short term one month operations planning horizon, the burden continues to shift to operations control center support entities. The primary operations normal and emergency planning involves TOPs, GOPs, and RCs.

5.2 Progression from Normal Steady State to Emergency Steady State time frame

In each of the above planning horizons, the analysis for the five system states need to be completed and documentation updated as necessary. The most limiting constraints for each system state need to be identified:

Normal Steady State
Transient (performance within 3 Seconds)
Post Transient Dynamic (performance within 30 Seconds)
Post Transient Load Flow (performance within 3 Minutes)
Emergency Steady State (within 30 Minutes after contingency)

Each functional entity must support its role in providing overall system state reliability, from longer term 5 year planning to actual operational implementation.

6 Technical Requirements

6.1 Documentation Requirements

6.1.1 Reactive Planning and Operating Technique

Documented protocols and expectations need to be established among key functional entities. Each major Planning Coordinator or logical association of several PCs should have a documented protocol (methodology or criteria) regarding expectations among the functional entities. For purposes of this document a logical electrical association of TPs and PCs will be called a "Transmission Planning Reactive Cluster (TPRC)". For coordinated planning and practical operation purposes, the TPRC planning association should align, to the extent practical, with one operations Reliability Coordinator (RC). In cases where one Reliability Coordinator covers an entire region, it is likely that one or more electrically cohesive TPRCs will be aligned with the RC for that region. Certain electrically cohesive TPRCs may overlap with multiple RCs. In such cases more than one RC will need to receive and review the TPRC set of documentation for its reactive planning criteria, and 5 year implementation plan. A more detailed description of the TPRC concept can be found in the attached APPENDIX 6: Functional Entity Mapping For Reactive Planning.

Detailed planning techniques vary across the United States and Canada. In some regions voltage level and voltage magnitude stability is a major concern and requires extensive study, while in other areas voltage problems rarely occur. However, in all cases the planning techniques (including operations planning) should be documented and made available to those functional entities which have a need to know in the region. A TPRC or several TPRCs may choose to have one common set of reactive planning technique documents. However, every TPRC should have such documentation. The planning technique documentation should be reviewed and updated periodically with input from best practices of other TPRCs.

As directed by FERC Order 693 (see APPENDIX 1 paragraphs 1861-1863, 1868-1871, 1875 and 1880) the document must include detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins (i.e. voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. The document must have defined requirements that clearly define what voltage limits are used and how much reactive resources are needed to ensure voltage instability will not occur under normal and emergency conditions.

Because reactive power needs vary significantly based on system characteristics and since the vast majority of reactive power must be supplied locally, there will be several TPRC reactive power associations within each of the NERC four Interconnections. It is also likely that several TPRC reactive power associations will exist within each of the eight NERC regions. Due to local system electrical characteristics, each TPRC will have different requirements for static and dynamic reserves. Also, there is likely a range of sufficient participation by generation, transmission and distribution resources within each TPRC. It is not appropriate to establish a NERC wide reactive reserve requirement.

6.1.2 Five-Year Implementation Plan

In addition to reactive planning technique documentation, a second set of planning documentation is needed. Multiple Transmission Planning Reactive Clusters (TPRCs) should review and coordinate plans by the functional entities involved in each system state (Section 5). This includes functional entity local plans for reactive support and control to maintain local system reliability and avoid permanent damage to their equipment. Collectively multiple TPRCs need to coordinate documentation of an integrated *Five-Year Reactive Support and Control Plan.* For purposes of this report, the complete *Five-Year Reactive Support and Control Plan* will be called the VAR Plan. This VAR Plan could be a collection of documentation from each functional entity, or a single integrated document. Each TPRC needs to have a complete set of documentation. As noted in the above Section 5, certain functional entities need to work together to provide a coordinated VAR Plan. As the near term approaches (1yr or less), other entities review and implement the as built plan.

During five year planning and shorter term operations planning, all five system states (see above Section 4) must be analyzed to identify reactive limitations resulting in TPL or other Standard criteria violations. Each system state may require additional reactive support and dynamic control system enhancements. Collectively, after all five system states are satisfied, the total reactive support and dynamic control requirements are known.   This includes local area requirements for enhanced static and dynamic reactive resources, and customer demand side management contracts (if any).

6.1.3 Planning Documentation and Operations Review Cycle

Both planning documents should be available to those functional entities that have a need to know within the region. In addition, each year the TPRC should deliver the VAR Plan to its associated Reliability Coordinator (RC). After operational review, the TPRC and RC should work together to make VAR Plan modifications deemed necessary for operational monitoring and implementation by the RC and TOPs.

The documented requirements should include performing voltage stability analysis periodically, using on-line techniques where practical and proven tools are commercially available and offline simulation tools where online tools are not available, to assist real-time operations. (see FERC order 693, paragraph #1875). The TPRC and RC should consider the available technologies and software as they modify the documented techniques (Section 6.1.1) and identify a process to assure that the documented techniques are not limiting the application of validated software or other tools. The five year VAR Plan shall include these enhancements.

The VAR Plan should include four major topics for implementation; 1) static resources, 2) dynamic resources, 3) local control system modifications and 4) control room system enhancements including TOP and RC monitoring responsibilities.

Both sets of final documentation (Section 6.1.1 techniques and Section 6.1.2 five year VAR Plan) should be a VAR Standard mandatory Requirement for each TPRC with full cooperation from its associated functional entities.

6.2 Topics which must be covered

The VAR Plan should identify firm contracts for customer demand side management and local area details regarding the size and type of reactive resources. The VAR Plan should also include any required changes to existing or new automatic local control systems.
The automatic control system portion of the VAR Plan should include the Normal Steady State automatic control schedules for key transmission bus, distribution delivery point, and generator buses. At a minimum these documented schedules should balance the Normal Steady State demand among reactive resources to maintain an appropriate system voltage profile and reactive power flow for that specific system. In addition the chosen Normal Steady State control schedules must not result in contingency criteria violations. When modeled during a variety of system peak customer load conditions, and other peak system transfer conditions, these balanced automatic control schedules indirectly result in a set of Dynamic Local Reactive Reserves for each Normal Steady State. Each five year VAR Plan is specific to the local areas under the jurisdiction of the TPRCs assigned to those functional entities. To the extent that local functional entities do not bring sufficient reactive resources to meet bulk electric system needs, including the Dynamic Local Reactive Reserves, the TPRC works with the functional entities to provide an adequate five year VAR Plan. If functional entity plans are not coordinated, the TPRC will provide the coordination necessary. Where multiple TPRCs exist within a region, a fixed region-wide reactive reserve requirement is not appropriate. Since reactive energy cannot be transmitted over long electrical distances, electrically nearby system requirements need to be coordinated by the nearby multiple TPRCs.

The Commission directed NERC to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities (PSEs). DP expectations regarding the ‘LSE power factor range’ at the boundary with the TO should be included in the VAR Plan. LSEs need to be treated on a comparable basis compared to PSEs. However, NERC Standards should only address reliability related issues. Financial equity issues need to be addressed by Federal, Provincial, or State jurisdictions.

Numerous other topics should be covered in a five year VAR Plan. However, the following key topics must be covered on an explicit basis based on local area characteristics.

6.2.1 "Equipment Limits"to prevent permanent damage to TO, GO, DP equipment

A) High Voltage Limit: Design basis limit to reduce insulation damage.
B) Low Voltage Limit: Used to identify possibility of motor excessive overheating caused by high currents during low voltage.
C) High AC Current Limit (optional): Time dependant design basis limit to reduce generator or motor overheating and resulting damage. When generator or motor current monitoring is availble, use of a time dependant "High Current Limit" is preferable to a "Low Voltage Limit" to avoid equipment damage.
D) High DC Exciter Current Limit (optional): Generator DC exciter systems produce reactive energy. While producing reactive energy to maintain AC voltage schedule, steady state rated DC field current should not be exceeded for a long period of time. This rated DC current limit, generator terminal High Voltage Limit and step-up transformer fixed tap setting should be coordinated with the TOP bus voltage schedule to be held by the GOP.

6.2.2 "Local Automatic and Manual Control" design (TO, GO and DP)

A) Dynamic voltage regulator (AVR) voltage setpoints and reactive power limits
B) Dynamic reactive power factor capability or other control mode setpoints and limits
C) Transformer and Voltage Regulaor tap changing under load setpoints and limits.
D) Transformer no load fixed tap settings to coordinate with voltage limits.
E) Switched Static reactive resources.
F) Fixed in-service reactive resources (line charging, fixed shunt capacitors and reactors, etc)

The above DP design also needs to address State required distribution system voltage regulation and limits.

6.2.3 "System Bus Voltage Collapse Control"

Protocol to avoid extreme voltage regulation problems (exponential voltage drops, voltage collapse, voltage magnitude instability, etc)

A) TPRC and TP functional entity protocol, criteria, or methodology to identify local areas, or individual busses which, under certain system conditions, may not have enough voltage regulation safety margin to avoid a voltage collapse.
B) TPRC and TP analysis method to identify key system bus Low Voltage Limit, Maximum Voltage Drop limit, Power Transfer Limit % safety margin, or other methods to avoid voltage collapse.
C) One year operations planning protocol to review and implement the above.
D) Real-time on-line methodology or off-line nomograms (based on existing technology). Item D to be implemented as necessary based on needs identified above.
E) Low Voltage Load Shed Limit; In addition to the above Section 6.2.1 and 6.2.3 low voltage operational limits, each TOP needs to know when load shedding

should be executed to avoid permanent equipment damage and system bus voltage collapse. For shunt load busses (equipment load) and key system busses, a Low Voltage Load Shed Limit (and associated methodology) must be documented by the TPRC with agreement from the TOP and RC.

6.2.4 "Reactive Energy Conservation Plan"

TPRC methodology to assure sufficient local and Interconnection wide reactive resources and demand side management.

A) Each of the NERC four Interconnections (ERCOT, Eastern Interconnection, etc) must be designed for a net tie flow of zero VARS on the Interconnection asynchronous ties (DC lines). The total net Interconnection power factor must be 1.0 PF. In other words 100% of firm customer reactive energy demand plus reactive energy losses must be supplied by reactive energy resources within the Interconnection. Frequency converters and AC/DC back to back converters can be a source for reactive energy. However, intentional plans for such sources need to be documented by the PC/TP within the Interconnection. Other resources for reactive energy conservation also include contracts for Demand Side Management customer load reductions which are shown to reduce system VAR losses or directly reduce customer VAR demand.

B) Since reactive energy cannot be transmitted over long electrical distances without causing large voltage drops, a cohesive set of TPRCs must plan for adequate reactive resources. The performance of reactive resources must meet customer reactive demand plus system reactive losses.

6.3 Distribution of the Interconnection's Reactive Resource Needs

The TPRC and the funtional entities within their jurisdiction should have one or more coordinated documents which describe the TPRC's protocol for VAR planning and operational implementation. Here are the basic topics which should be documented for the Normal Steady State system conditions:.

6.3.1 Transmission to Distribution boundary

For a given set of TO to DP boundary connections, establish forecasted power factor expectations for the DP total net reactive demand supplied across the TO to DP interface boundary. The forecast quality control documentation should include a periodic real-time MW and Mvar survey of the peak day power factor. Depending upon available SCADA or other recording meter locations, loss compensation calculations may need to be performed to reconcile the survey data to the forecasted power factor at the TO to DP boundary. The power factor forecast error should be documented on a periodic basis, and appropriate changes made to the forecast, or changes made to the DP five year plan. With concurrence by the TO, a minimum power factor needs to be agreed upon by the DP entity. The DP must take action in each year of the VAR Plan to correct its actual MW/Mvar average survey performance to meet or exceed the agreed upon minimum power factor. The DP total net reactive demand at the TO/DP boundary does not need to be unity Power Factor since the GO supplying customer real power energy will also supply some of the DP reactive demand at the GO/TO point of interconnection. However, the GO will maintain a pre-determined automatic control schedule and will not be able to transmit its full capability to the TO/DP boundary. GOs directly connected within the DP boundary will supply reactive energy directly. However, GOs electrically remote from customers will not be able to transmit all of the customer reactive energy demand due to system reactive energy losses and voltage drops. Although reliability constraints may not require unity power factor at the TO/DP boundary, in the long term Federal, Provincial and State tariffs regarding cost of service per installed KVAR resource will likely drive an appropriate cost equity solution and a mutually agreeable power factor on the TO/DP boundary. That decision is primarily an equity issue and best handled by Provincial, State and Federal entities. That financial equity topic is beyond the scope and reliability jurisdiction of NERC.

The forecast for the 5th year of the planning horizon regarding the TO/DP boundary power factor should be based on both actual MW and Mvar survey information and forecasted DP system, DP-customer, and generation incremental changes expected to occur within the 5 year period after the last MW/Mvar survey.

6.3.2 Transmission to Generation boundary

At the TO to GO interconnection boundary, establish minimum and maximum power factor expectations for the GO functional entity. This should include a periodic real-time MW and Mvar survey of the power factor at a given electrical boundary agreed upon by the TO and GO entities. In the 5 year forecast horizon, the TO/GO boundary minimum and maximum power factor forecast should recognize both actual MW and Mvar survey information, GO entity verifiable capability, and forecasted GO entity facility changes within the five year planning horizon. FERC has established the power factor requirements at the point of interconnection for new Large Generators.   Other existing or new generators must provide their power factor capability which existed on the date of their most recently signed Interconnection Service Agreement.

6.3.3 TPRC to TPRC boundary

A similar document is needed for ‘TPRC #1’ to ‘TPRC #2’ association boundary. All TOs within a given TPRC boundary should provide the remaining reactive resource ‘capability’ required to balance the reactive energy demand on the TPRC during Normal Steady State peak load demand.   Actual reactive energy demand on the boundary between TPRCs would not be scheduled in actual operation. However, each TPRC should have the reactive resource ‘capability’ to balance reactive demand under RC direction and TOP operator control within 30 minutes. In some cases electrically coherent TPRCs and their associated PCs may span more than one RC.   In such cases TPRC/PCs must coordinate with multiple RCs. In these cases the operational implementation plan will affect more than one RC. Both traditional reactive sources and contract demand side management should be under RC/TOP operator control within 30 minutes. If not, those reactive resources would not be counted as part of the RC/TOP reactive resources.

6.3.4 Dynamic Var Requirements

Each TPRC should have the written allocation planning methodology ready for operational review by its associated Reliability Coordinator (RC) within 30 days of RC request. One uniform North American method is probably not optimal. But a written method must exist within each TPRC and available for peer review by the RC. As part of the VAR Plan, capability shall be provided for RC reactive monitoring as jointly deemed appropriate by the TPRC and RC. The RC should have adequate monitoring capability and take action if reactive power or voltage falls outside identified limits.

7 Financial Equity Considerations

7.1 NERC Reliability Standards address reliability issues

Dynamic reactive power reserves should be differentiated from static reactive power. Dynamic sources provide more control and ability to reduce major voltage drops during system emergencies. In addition, dynamic reserves from self excited generation equipment are inherently more effective than devices using shunt capacitor compensation. The reactive output of shunt capacitors reduces in proportion to the square of voltage magnitude. In contrast self excited generation excitation systems have a very high short time reactive output capability under low voltage conditions, and at rated voltage their maximum steady state reactive output can be sustained indefinitely. These factors should be recognized as further financial equity research proceeds as discussed below in section 7.2.

7.2 FERC, Provincial and State Commissions address Functional Entity equity issuess

Research on additional software tools may be needed to optimize real-time generator dispatch based on the availability and control of reactive resources. However, any such advanced optimization must not degrade reliability. These financial equity debates continue to exist primarily due to lack of advanced state of the art software to optimize actual and potential use of reactive supply while maintaining reliability. The cost optimization of reactive planning and operation within each functional entity (GO, TO, and DP) is an area of future research, debate and practical application. The reactive supply cost, system optimization, and related tariff equity issues are beyond the scope of this report.

8 Example 'How To' Protocols

8.1 WECC approach

Several existing examples of reactive support and control methodologies are available for review. One such example of a methodology to set transfer limits to avoid loss of voltage regulation control is shown in APPENDIX 8a & 8b. This example is being presented as one of many available methods being used by the industry today.

8.2 PJM approach

Another example is shown in APPENDIX 9: PJM Reactive Support and Voltage Control. This example includes RC/TOP monitoring of key reactive support and voltage regulation control methods – generation scheduled voltage control performance, contingency voltage drop prediction, and frequently updated power transfer limits and control margins. This example is being presented as one of many available methods being used by the industry today.

8.3 ISO New England Operating Procedure 17 Appendix B

Another example is shown in APPENDIX 10: ISO New England Op Procedure 17 Appendix B. This appendix includes a methodology to establish minimum and maximum load power factor limits at three discrete load levels: heavy, medium, and light load. This methodology is being presented as another example of available methods being used by the industry.

8.4 Voltage Stability measurement techniques industry and academic papers

Numerous academic papers exist on this topic. As state of the art techniques are shown to be practical for implementation, the industry should continue to improve its methods to identify and control a voltage collapse. For further reading please see APPENDIX 11 bibliography. Further research and development is warranted using such methodologies.

8.5 Other Existing Examples

EXAMPLE 5:

8.5.1 Part A: New Large Generator

- FERC Order 2003 - Final Rule Issued 7/24/03.

- Para# 543. "We adopt the power factor requirement of 0.95 leading to 0.95 lagging because it is a common practice in some NERC regions."
- If Transmission Provider wants to adopt different power factor requirement, Article 9.6.1 permits it as long as the requirement applies to all generators on comparable basis.
- Above PF requirement is computed at GO/TO contract point of interconnection.

8.5.2 Part B: Reactive Supply at TO / DP designated boundary

- To be based on TO/DP interface peak load actual power factor performance.
- Sufficient reactive compensation shall be installed within the Distribution Provider's system to reach a minimum power factor of 9X% or higher as approved by the TPRC. 9X% shall not be lower than 95% PF supply by generators for customer load.
- Conservation of Reactive Energy
    - Only a portion of 'nearby' reactive energy source capability can be shared among Transmission and Distribution Provider entities.
    - The remaining 100%-9X% difference in power factor should be obtained by the DP (at LSE expense) by either DP sharing reactive compensation installed on the associated TO's system, or DP installing (at LSE expense) additional reactive compensation within the DP's system.

8.5.3 Part C: Reactive Supply at GO / TO point of interconnection

- Based on GO/TO interface peak load actual power factor performance, sufficient reactive compensation shall be installed within the GO's system to reach a minimum lagging power factor capability of 9Y% or higher at the point of interconnection. The lagging 9Y% power factor shall not be chosen to be lower than the FERC tariff requirements.
- GO/TO interface power factor shall not be lower than the GO related reactive supply capability at the time the most recent GO/TO interconnection service agreement was signed.
    - The power factor should be calculated based on generator 'point of interconnection'. If point of interconnection is not the high side of the generator step-up transformer, the generator stepup transformer reactive energy losses shall be the generator's responsibility.
- New large generators shall have a lagging power factor capability of 95% (or better) at their point of interconnection. (Per FERC rule).
- Any GO proposed permanent change to its point of interconnection reactive power output capability shall be reviewed and approved by the associated TPRC.

8.5.4 Part D: Conservation of Reactive Energy at boundary with multiple TOs within an electrically coherent TPRC

- The remaining reactive resources needed to maintain a near unity power factor within a electrically coherent TPRC are to be coordinated by a logical set of cohesive TOs within the TPRC. The reactive resource sharing agreement among multiple TOs will be developed in an open process, and the integrated planning documentation made available to the associated TPRC. If the TPRC does not concur with the five year plan, the TPRC and TOs will jointly resolve the implementation issues. Absent TPRC/TO agreement, Alternative Dispute Resolution within the region will be used to resolve the dispute.

8.5.5 Part E: Conservation of Reactive Energy at boundary with multiple TPRCs

- The remaining reactive resources needed to maintain a total net unity power factor at the NERC Interconnection DC tie line boundaries are to be coordinated by a logical set of cohesive TPRCs. The reactive resource sharing agreement among multiple TPRCs will be developed in a open process, and the integrated planning documentation made available to the associated Relibility Coordinators (RCs) for implementation. If the RCs do not concur with the five year plan, the TPRCs and RCs will jointly resolve the implementation issues. Absent TPRC/RC agreement, Alternative Dispute Resolution within the reliability region will be used to resolve the dispute.
    -

8.5.6 Part F: Dynamic Reactive Reserve

- Generators provide vital self energized dynamic response to disturbances, and thus shall NOT be planned to be operated for more than 30 minutes at 100% rated DC field current and not at 100% AC MVA stator limits.
- Stressed units operating in excess of full load rated field current (100% reacive output) on a steady state basis may result in exciter protection tripping the automatic voltage regulator (AVR) to manual, and risk tripping the unit's excitation system.
- Generators are often designed to withstand 200% rated DC field current for a few minutes and then trip AVR to manual control at 100% rated field current. Transmission system Post Transient capacitor compensation design should plan to return manual exciter control to AVR within 30 minutes at a voltage schedule which requires less than 100% rated DC field current and less than 100% of the rated AC MVA stator limit.

- FACTS devices (SVCs, etc) provide dynamic response. However, since they are not self energized, their dynamic response is diminished during severe voltage depressions. In a similar fashion to generators, these devices should not be planned to be operated at 100% rated output for more than 30 minutes.

- Sufficient Transmission system switched static devices shall be planned to provide a ZZ% or more system dynamic Mvar reserve capability. The total ZZ Mvar dynamic reserve within an electrically coherent TPRC shall not be less than 5% of the TPRC system's total Mvar demand (including losses).

See APPENDIX 7: Example Reactive Cluster and Dynamic Reserve Tests. This Appendix shows a complete set of tests for TPRC determination, and the portion of Dynamic Reserves versus Static resources.

8.5.7 Part G: EXAMPLE of Equipment and System Voltage Limits

- **Transformers**

Transformers shall stay within rated voltage limits, at rated frequency and rated kVA for any tap, based on ANSI C57.12.00 1980. Transformers within this TPRC should be capable of:

  - Delivering rated output at 5% above rated secondary voltage without exceeding the limiting temperature rise (when the power factor of the load is 80% or higher).
  - Operating at 10% percent above rated secondary voltage at no load without exceeding the limiting temperature rise.

- **Motors**

Motors shall stay within rated voltage limits, at rated frequency and rated KVA, based on NEMA – Standards Publication MGI-1972; Sections MGI-12.43, MGI-20.45 and MGI-11. Motors within this TPRC are expected to be capable of PA PUC Electric Regulations, Service Rule 4, which states that voltage, primarily for lighting purposes, at the customer's meter shall not exceed, between sunset and 11:00 PM, the nominal standard service voltage (120V) by $\pm$ 5% and a total variation from minimum to maximum of 8%. At other times during which service is supplied a total variation from minimum to maximum of 10% is allowed.

- **Generation Units**
  - Generators 25 MVA or above shall stay within rated voltage limits (at rated frequency and rated MVA), based on the as built manufacturer design specifications. Unless noted otherwise on a case-by-case basis, generators within this TPRC should be capable of any voltage not more than 5% above or below rated nameplate voltage. In lew of the 5% low voltage limit, an optional stator High Current Limit (based on rated MVA) may be used under lower voltage temporary operation.

  - <u>Generator Step-Up (GSU) Transformer</u>: The desired maximum and minimum high side bus voltage schedules must be provided by the TOP to the GO. The generator should be able to meet the highest voltage schedule with maximum rated watt and var output without exceeding 105% of rated generator voltage.

The GSU fixed tap setting shall be chosen to permit rated lagging var output. The GOP minimum leading var output limit given to the TOP will be based on the most limiting of leading var thermal capability or generator auxiliary motor load center low voltage limitations. Thus, a compromise fixed tap may be necessary. The GOP will notify the PC and TOP of the var and Voltage limitations.

  - <u>Generator Auxiliary Transformer:</u> The fix tap setting will be set to provide acceptable voltage for the unit auxiliary equipment without exceeding the over-excitation limits of the transformer. Auxiliary bus voltage will not cause auxiliary motor terminal voltages to exceed $\pm$ 10% of rated. The fixed tap setting will recognize that generator terminal voltage may be varied $\pm$ 5% of rated nameplate voltage.

- Transmission System Bus – Low Voltage Limitations
  - At key transmission system busses, determined by the TP or TOP, voltage drops should be limited to 95% of nominal or normal, whichever is higher. In addition, for transfer limit interfaces, 5% limit safety margin (no less than YYY MW) shall also be maintained to avoid an uncontrollable voltage drop. At these key system busses studies have shown severe uncontrollable low voltage may occur in excess of these system bus Low Voltage Limitations.
  - Load Shed Low Voltage Limit:
    On transmission system busses with MOD load flow Shunt Load representing TO or DP customer load, if the TO or DP has no automatic voltage regulators, the Load Shed Low Voltage Limit shall be set 7.5% below normal or scheduled voltage. The TOP shall shed a portion or all of the Shunt Load to protect motors from permanent damage. The DP primary voltage (on a 120 volt base) shall not fall below 111 volts on-peak and 108 volts off-peak. These voltages are 7.5% below minimum voltages during normal operation and correspond to customer point of contact voltage of about 105 volts. This is one volt above the minimum utilization voltage for non-lighting loads for voltage range B as defined in the "American National Standard Voltage Rating for Electric Power Systems and Equipment (60 Hertz)", ANSI C84.1-1977. Voltage drops in excess of 7.5% from normal require corrective action, including load shedding, to avoid customer equipment damage.

8.6 Example - Transmission Planning Reactive Cluster (TPRC) determination

For a detailed description of the TPRC concept, please see APPENDIX 6: Functional Entity Mapping For Reactive Planning.

8.7 Example - Conservation of Reactive Energy determination

For a detailed method of how to test for TPRC reactive coherency, please see APPENDIX 7: Example Reactive Cluster and Dynamic Reserve Tests. This example is being presented as one of many possible methods to test for TPRC reactive coherency. For each TPRC or group of TPRCs within a given RC footprint, such a criteria methodology should be documented, and reviewed by those functional entities supporting both planning and operational reliability within the RC footprint.

APPENDIX 1

VAR-001-1 FERC Directives and other Industry Comments

APPENDIX 1 VAR-001-1 FERC Directives and other Industry Comments

STATUS: VAR-001-1 Voltage and Reactive Control

FERC Order 693

Disposition VAR-001-1: Approve with modifications
Order 693 directives:

• Expand the applicability to include LSEs and reliability coordinators and define the reliability coordinators monitoring responsibilities. (para# 1855)
• Address reactive power requirements for LSEs on a comparable basis with purchasing-selling entities. (para# 1856 and 1858)
• Include APPA's comments regarding varying power factor requirements due to system conditions and equipment in the standards development process. (para#1857)
• Include detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identify acceptable margins above the voltage instability points. (para# 1868 to 1871)
• Address the concerns of Dynegy, EEI, and MISO through the standards development process. (para# 1864-1866)
• Perform voltage analysis periodically, using on-line techniques where commercially available and off-line techniques where not available online, to assist real-time operations, for areas susceptible to voltage instability. (para# 1875)
• Include controllable load among the reactive resources to satisfy reactive requirements, considering the comments of Southern California Edison and SPA in the development of the standard. (para# 1879)
• Address the power factor range at the interface between LSEs and the transmission grid. (para# 1861-1863)

- Summary (para#1880)

V0 Industry Comments

• Not a standard but a business practice
• Expand to include relays
• Define voltage levels
• Clarify if this includes distribution
• Clarify responsibility for voltage support
• Add GO as entity
• Mention power factor requirements for distribution
• Add BA (R1 and 3) and RA (R5, 7, 8, 10 and 11)
• Move R9 to 5.2
• Delete SOL violations
• Define high probability

Phase III/IV comments

• No requirement for verifying that the reactive resources are truly available.
• No criteria for what is an acceptable reactive margin.
o R3, R6, R10 go beyond the control of the responsible entity noted.
o R3, the Transmission Operator only has the reactive resources that exist in the area - how does the TO "acquire sufficient reactive resources" if existing resources are not adequate?
o Should R3 be assigned to the TP?
o Should the word "acquire" in R3 be replaced with the word "operate"?
o R6 and R10.1 presume that sufficient reactive resources are available.
• R3 covers normal and contingency conditions, while R10 mentions only first contingency conditions. Is there a reason for this difference?
• R3 Suggest changing the phrase…"to protect the voltage"…. to "maintain the voltage"
• What does the second sentence in R3 mean by the phrase ”transmission operator's share of the reactive requirements of interconnecting transmission circuits’? What would be the reactive requirements of transmission circuits?
• R5 This requirement is an Open Access Transmission Tariff requirement and does not belong in a reliability standard.
• Will R6 also apply to wind generation absorbing reactive power at the point of interconnection?
• R7 obligates Transmission Operators to know the status of all reactive power sources including AVRs and PSSs. Clarify that this means the generator is available and if dispatched will operate in voltage control mode and with the PSS active.
• R7 and R8 – consider adding more specificity to distinguish the TOP’s authority to direct others to operate (Each Transmission Operator shall operate owned devices or direct the operation of, within their normal operating parameters and capabilities, capacitive and inductive reactive resources within its area including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding- to maintain system and Interconnection voltages within established limits.)
• Consolidate R8 and R9
• R9.1 this requirement is not feasible. Cannot dictate where generation resources are to be disbursed or located.
• R10 remove "first" so as not to limit this requirement to first contingency conditions. As written with or without removing "first", R10 provides no additional information not already required in R3.
• R10.1 does 'disperse and locate' mean the same as 'dispatch'? If so, changing the wording to 'dispatch' would make the meaning clearer.
• R11 –Redundant with TOP-007
• The language in the measures and compliance sections such as "2.1.2
One incident of failing to maintain a voltage or reactive power schedule" is too vague and does not specify any duration that is acceptable or unacceptable to be off schedule.
• VAR-001 requirements (R1, R2, R7, R8, R9, R10, and R12) are redundant to the TOP standards.

Other

• Modify standard to conform to the latest version of NERC’s Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

Relevant FERC Order 693 Paragraphs:

13. VAR: Voltage and Reactive Control

1846. The Version 0 Voltage and Reactive Control (VAR) Reliability Standard VAR-001-0 is intended to maintain Bulk-Power System facilities within voltage and reactive power limits, thereby protecting transmission, generation, distribution, and customer equipment and the reliable operation of the Interconnection. The Voltage and Reactive Control group of Reliability Standards is intended to replace the existing VAR-001-0 and consists of two proposed Reliability Standards, VAR-001-1 and VAR-002-1, with new Requirements. These two new proposed Reliability Standards have been submitted by NERC as part of the August 28, 2006 Supplemental Filing for Commission review. NERC requested an effective date of February 2, 2007 for VAR-001-1, and August 2, 2007 for VAR-002-1.

a. VAR-001-1 Voltage and Reactive Control

1847. Reliability Standard VAR-001-1 requires transmission operators to implement formal policies for monitoring and controlling voltage levels, acquire sufficient reactive resources, specify criteria for generator voltage schedules, know the status of all transmission reactive power resources, operate or direct the operation of devices that regulate voltage and correct IROL or SOL violations resulting from reactive resource deficiencies. VAR-001-1 also requires purchasing-selling entities to arrange for reactive resources to satisfy their reactive requirements.

1848. In the NOPR, the Commission proposed to approve VAR-001-1 as mandatory and enforceable. In addition, the Commission proposed to direct NERC to submit a modification to VAR-001-1 that: (1) expands the applicability to include reliability coordinators and LSEs; (2) includes detailed and definitive requirements on "established limits" and "sufficient reactive resources," and identifies acceptable margins above the voltage instability points; (3) includes Requirements to perform voltage stability assessments periodically during real-time operations and (4) includes controllable load among the reactive resources to satisfy reactive requirements. The Commission also requested comments concerning NERC's assertion that all LSEs are also purchasing-selling entities, and on the acceptable ranges of net power factor range at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions.

1849. Most comments address the specific modifications and concerns raised by the Commission in the NOPR. Below, we address each topic separately, followed by an over-all conclusion and summary.

i. Applicability to Load-Serving Entities and Reliability Coordinators

(a) Comments

1850. EEI agrees with the Commission that the applicability of VAR-001-1 should be expanded to include reliability coordinators and LSEs.

1851. MISO contends that the view and role of generator operators, transmission operators and reliability coordinators are different, and reliability coordinators' monitoring and response requirements are addressed elsewhere in the Reliability Standards.

1852. In response to the Commission's request in the NOPR for comments concerning whether all LSEs are also purchasing-selling entities, SoCal Edison believes they are distinguishable. It states that a purchasing-selling entity, according to the functional model, makes financial deals across balancing authorities (from source to sink). Within the area of a large balancing authority, such as the CAISO, an LSE can serve load from a resource within the balancing authority, so that there is no requirement to tag this transaction, and technically there is no purchasing-selling entity involved.

1853. APPA is concerned that requiring VAR-001-1 to be applicable to LSEs would require LSEs to conduct various studies and perform reliability functions that have been assigned to other functional entities. The role of LSEs in voltage stability assessments should be limited to coordination and the provision of data. TAPS also questions the need to expand applicability of these Reliability Standards to LSEs. TAPS maintains that purchasing and selling utilities are already subject to the Reliability Standards, and are required to satisfy any reactive requirements through purchasing Ancillary Service No. 2 under the OATT (or self-supply). TAPS believes that the addition of LSEs as an additional applicable entity serves no reliability purpose.

(b) Commission Determination

1854. In a complex power grid such as the one that exists in North America, reliable operations can only be ensured by coordinated efforts from all operating entities in long term planning, operational planning and real-time operations. To that end, the Staff Preliminary Assessment recommended and the NOPR proposed that the applicability of VAR-001-1 extend to reliability coordinators and LSEs.

1855. Since a reliability coordinator is the highest level of authority overseeing the reliability of the Bulk-Power System, the Commission believes that it is important to include the reliability coordinator as an applicable entity to assure that adequate voltage Docket No. RM06-16-000 - 480 - and reactive resources are being maintained. As MISO points out, other Reliability Standards address responsibilities of reliability coordinators, but we agree with EEI that it is important to include reliability coordinators in VAR-001-1 as well. Reliability coordinators have responsibilities in the IRO and TOP Reliability Standards, but not the specific responsibilities for voltage levels and reactive resources addressed by VAR-001-1, which have a great impact on system reliability. For example, voltage levels and reactive resources are important factors to ensure that IROLs are valid and operating voltages are within limits, and that reliability coordinators should have responsibilities in VAR-001-1 to monitor that sufficient reactive resources are available for reliable system operations. Accordingly, the ERO should modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.

1856. The Commission agrees with SoCal Edison that not all LSEs are purchasing-selling entities, because not all LSEs purchase or sell power from outside of their balancing authority area. This understanding is consistent with the NERC functional model and NERC glossary. Both LSEs and purchasing-selling entities should have some requirements to provide reactive power to appropriately compensate for the demand they are meeting for their customers. Neither a purchasing-selling entity nor a LSE should depend on the transmission operator to supply reactive power for their loads during normal or emergency conditions.

1857. VAR-001-1 recognizes that energy purchases of purchasing-selling entities can increase reactive power consumption on the Bulk-Power System and the purchasing-selling entities must supply what they consume. The Commission agrees with APPA that LSEs would provide data for voltage stability assessments. However, the Commission also believes that LSEs have an active role in voltage and reactive control, since LSEs are responsible for maintaining an agreed-to power factor at the interface with the Bulk- Power System.

1858. While the Commission recognizes the point made by TAPS, that purchasing-selling entities are required to satisfy any reactive requirements through purchasing Ancillary Service #2 under the OATT or self-supply, the Commission disagrees that adding LSEs to this Reliability Standard serves no reliability purpose. As discussed in the NOPR and the Staff Preliminary Assessment, LSEs are responsible for significantly more load than purchasing-selling entities.[471] The reactive power requirements can have significant impact on the reliability of the system and LSEs should be accountable for that impact in the same ways that purchasing-selling entities are accountable, by providing reactive resources, and also by providing information to transmission operators to allow transmission operators to accurately study the reactive power needs for both the LSEs' and purchasing-selling entities' load characteristics.[472] The Commission recognizes that all transmission customers of public utilities are required to purchase Ancillary Service No. 2 under the OATT or self-supply, but the OATT does not require them to provide information to transmission operators needed to accurately study reactive power needs. The Commission directs the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.

ii. Acceptable ranges of net power factor range

(a) Comments

1859. SoCal Edison states that its Bulk-Power System facilities are designed and operated to provide a unity power factor during normal load conditions, and that during extreme load conditions, this power factor could be in the range of 0.95 to 1.0.

Footnote: [472] Purchasing-selling entities provide information concerning their load through the INT series of Reliability Standards. Load serving entities would need to provide similar information through this Reliability Standard.

1860. APPA contends that it may be difficult to reach an agreement on acceptable ranges of net power factors at the interfaces where LSEs receive service from the Bulk-Power System because the acceptable range of power factors at any particular point on the electrical system varies based on many location-specific factors. APPA further states that system power factors will be affected by the transmission infrastructure used to supply the load. As an example, APPA states that an overhead circuit may operate at a higher power factor than an underground cable due to a substantial amount of reactive line charging, and that a transmission circuit carrying low levels of real power will tend to provide more reactive power, which will affect the need to switch off capacitor banks at the delivery point to manage delivery power factors.

(b) Commission Determination

1861. In the NOPR, the Commission asked for comments on acceptable ranges of net power factor at the interface at which the LSEs receive service from the Bulk-Power System during normal and extreme load conditions. The Commission asked for these comments in response to concerns that during high loads, if the power factor at the interface between many LSEs and the Bulk-Power System is so low as to result in low voltages at key busses on the Bulk-Power System, then there is risk for voltage collapse.

The Commission believes that Reliability Standard VAR-001-1 is an appropriate place for the ERO to take steps to address these concerns by setting out requirements for transmission owners and LSEs to maintain an appropriate power factor range at their interface. We direct the ERO to develop appropriate modifications to this Reliability Standard to address the power factor range at the interface between LSEs and the Bulk- Power System.

1862. We direct the ERO to include APPA's concern in the Reliability Standards development process. We note that transmission operators currently have access to data through their energy management systems to determine a range of power factors at which load operates during various conditions, and we suggest that the ERO use this type of data as a starting point for developing this modification.

1863. The Commission expects that the appropriate power factor range developed for the interface between the bulk electric system and the LSE from VAR-001-1 would be used as an input to the transmission and operations planning Reliability Standards. The range of power factors developed in this Reliability Standard provides the input to the range of power factors identified in the modifications to the TPL Reliability Standards. In the NOPR, the Commission suggested that sensitivity studies for the TPL Reliability Standards should consider the range of load power factors.[473]

Footnote: [473] NOPR at P 1047.

iii. Requirements on “established limits” and “sufficient reactive resources”

(a) Comments

1864. Dynegy supports the Commission’s proposal to include more definitive requirements on “established limits” and “sufficient reactive resources.” It recommends that VAR-001-1 be further modified to require the transmission operator to have more detailed and definitive requirements when setting the voltage schedule and associated tolerance band that is to be maintained by the generator operator. Dynegy states that the transmission operator should not be allowed to arbitrarily set these values, but rather should be required to have a technical basis for setting the required voltage schedule and tolerance band that takes into account system needs and any limitations of the specific generator. Dynegy believes that such a requirement would eliminate the potential for undue discrimination, as well as the possibility of imposing overly conservative and burdensome voltage schedules and tolerance bands on generator operators that could be detrimental to grid reliability, or conversely, the imposition of too low a voltage schedule and too wide a tolerance band that could also be detrimental to grid reliability.

1865. While MISO supports the concept of including more detailed requirements, it believes that there needs to be a definitive reason for establishing voltage schedules and tolerances, and that any situations monitored in this Reliability Standard need to be limited to core reliability requirements.

1866. EEI seeks clarification about whether the Commission is suggesting that reactive requirements should aim for significantly greater precision, especially in terms of planning for various emergency conditions. If so, EEI cautions the Commission against “‘putting too many eggs’ in the reactive power ‘basket.’”[474] To the extent compliance takes place pursuant to all other modeling and planning assessments under the other Reliability Standards, EEI strongly believes that the Commission should have some high level of confidence that the system’s reactive power needs can be met satisfactorily across a broad range of contingencies that planners might reasonably anticipate. Moreover, EEI believes that requirements to successfully predict reactive power requirements in conditions of near-system collapse would require significantly more creative guesswork than solid analysis and contingency planning. For example, EEI notes that the combinations and permutations of how a voltage collapse could occur on a system as large as the eastern Interconnection are numerous.

Footnote: [474] EEI at 99.

1867. EEI suggests that, alternatively, the Commission should consider that reactive power evaluations should be conducted within a process that is documented in detail and includes a range of contingencies that might be reasonably anticipated, because this would avoid the ‘one size fits all’ problem, where a prescriptive analytical methodology does not fit with a particular system configuration. EEI believes that this flexible approach would provide a more effective planning tool for the industry, while satisfying the Commission’s concerns over potentially inadequate reactive reserves. MRO notes that the need for, and method of providing for, reactive resources varies greatly, and if this Reliability Standard is expanded it must be done carefully.

MRO believes that all entities should not be required to follow the same methodology to accomplish the goal of a reliable system.

(b) Commission Determination

1868. In the NOPR, the Commission expressed concern that the technical requirements containing terms such as "established limits" or "sufficient reactive resources" are not definitive enough to address voltage instability and ensure reliable operations.[475] To address this concern, the NOPR proposed directing the ERO to modify VAR-001-1 to include more detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins (i.e. voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. We will keep this direction, and direct the ERO to include this modification in this Reliability Standard.

1869. We recognize that our proposed modification does not identify what definitive requirements the Reliability Standard should use for "established limits" and "sufficient reactive resources." Rather, the ERO should develop appropriate requirements that address the Commission's concerns through the ERO Reliability Standards development process. The Commission believes that the concerns of Dynegy, EEI and MISO are best addressed by the ERO in the Reliability Standards development process.

1870. In response to EEI's concerns about a prescriptive analytical methodology, we clarify that the Commission is not asking that the Reliability Standard dictate what methodology must be used to determine reactive power needs. Rather, the Commission believes that the Reliability Standard would benefit from having more defined requirements that clearly define what voltage limits are used and how much reactive resources are needed to ensure voltage instability will not occur under normal and emergency conditions. For example, in the NOPR, the Commission suggested that NERC consider WECC's Reliability Criteria, which contain specific and definitive technical requirements on voltage and margin application. While we are not directing that the WECC reliability criteria be adopted, we believe they represent a good example of clearly-defined requirements for voltage and reactive margins.

Footnote: [475] See NOPR at P 1140.

1871. In sum, the Commission believes that minimum requirements for voltage levels and reactive resources should be clearly defined by placing more detailed requirements on the terms "established limits" and "sufficient reactive resources" in the Reliability Standard as discussed in the NOPR and the Staff Preliminary Assessment. As mentioned above, EEI's concerns should be considered in the ERO's Reliability Standards development process.

iv. Periodic voltage stability analysis in real-time operations

(a) Comments

1872. SDG&E supports the NOPR recommendation that a more effective requirement could be based on WECC's reliability criteria, which contain specific and definitive technical requirements on voltage and margin application. MidAmerican and TPRCifiCorp recommend that the "WECC Methods to address voltage stability and settling margins" should be consulted when designing corresponding NERC requirements.

1873. Xcel Energy recommends that this proposed modification instead address requirements to measure reactive power margin for a variety of topology conditions. MidAmerican recommends that the Commission's proposal be modified to require real-time checks for voltage stability assessments only in areas susceptible to voltage instability. Alternatively, MidAmerican suggests that the Commission "should exempt from these requirements areas that can demonstrate they are not susceptible to voltage instability."

1874. APPA, SDG&E and EEI all state that they are not aware of commercially available tools to provide real-time transient stability assessments as part of an integrated energy management system for operators. APPA notes that premature reliance on various tools that are now under development but not yet operational may jeopardize reliability by providing operators with a false sense of security and recommends leaving the decision to use such tools to NERC. EEI points out that any tools to conduct the analyses recommended by the Commission will require adjustments and modifications to improve their capabilities. Therefore, EEI recommends that the Commission consider its proposals regarding these standards as long-term industry objectives and of a lower priority than other Reliability Standards. In addition, it is unclear to EEI whether the proposed voltage stability assessments apply to steady-state or dynamic analyses, or whether these assessments are of a general nature. Since these analyses are technically complex and involve a broad range of assumptions regarding system configurations, EEI suggests that the Commission provide further guidance.

(b) Commission Determination

1875. In response to the concerns of APPA, SDG&E and EEI on the availability of tools, the Commission recognizes that transient voltage stability analysis is often conducted as an offline study, and that steady-state voltage stability analysis can be done online. The Commission clarifies that it does not wish to require anyone to use tools that are not validated for real-time operations. Taking these comments into consideration, the Commission clarifies its proposed modification from the NOPR. For the Final Rule, we direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations. The ERO should consider the available technologies and software as it develops this modification to VAR-001-1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools.

1876. With respect to MidAmerican's suggestion of exempting areas that are not susceptible to voltage instability from the requirement to perform voltage stability analysis, the Commission notes that such exemption is not appropriate. We draw an analogy between transient stability limits and voltage stability limits. The requirement to perform voltage stability analysis is similar to existing operating practices for IROLs that are dictated by transient stability. Transient stability IROLs are determined using the results of off-line simulation studies, and no areas are exempt. In real-time operations, these IROLs are monitored to ensure that they are not violated. Similarly, voltage stability is conducted in the same manner, determining limits with off-line tools and monitoring limits in real-time operations. Areas that are susceptible to voltage instability are expected to run studies frequently, and areas that have not been susceptible to voltage instability are expected to periodically update their study results to ensure that these limits are not encountered during real-time operations.

v. Controllable Load

(a) Comments

1877. SMA supports adoption of the proposal to include controllable load as a reactive resource. SMA notes that its members' facilities often include significant capacitor banks, and further, reducing load can reduce local reactive requirements.

1878. SoCal Edison suggests caution regarding the Commission's proposal to include controllable load as a reactive resource. It agrees that, when load is reduced, voltage will increase and for that reason controllable load can lessen the need for reactive power. However, SoCal Edison believes that controllable load is typically an energy product and there are other impacts not considered by the Commission's proposal to include controllable load as a reactive resource. For example, activating controllable load for system voltage control lessens system demand, requiring generation to be backed down. It is not clear to SoCal Edison whether any consideration has been given to the potential reliability or commercial impacts of the Commission's proposal.

(b) Commission Determination

1879. The Commission noted in the NOPR that in many cases, load response and demand-side investment can reduce the need for reactive power capability in the system.[476] Based on this assertion, the Commission proposed to direct the ERO to include controllable load among the reactive resources to satisfy reactive requirements for incorporation into Reliability Standard VAR-001-1. While we affirm this requirement, we expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards.

vi. Summary of Commission Determination

1880. Accordingly, the Commission approves Reliability Standard VAR-001-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and §39.5(f) of our regulations, the Commission directs the ERO to develop a modification to VAR-001-1 through the Reliability Standards development process that:
(1) expands the applicability to include reliability coordinators and LSEs;
(2) includes detailed and definitive requirements on "established limits" and "sufficient reactive resources" as discussed above, and identifies acceptable margins above the voltage instability points;

(3) includes Requirements to perform voltage stability analysis periodically, using online techniques where commercially available and offline techniques where online techniques are not available, to assist real-time operations, for areas susceptible to voltage instability;
(4) includes controllable load among the reactive resources to satisfy reactive requirements and
(5) addresses the power factor range at the interface between LSEs and the transmission grid.

Footnote: [476] See FERC Staff Report l, Principles of Efficient and Reliable Reactive Power Supply and Consumption (2005), available at http://www.ferc.gov/legal/staff-reports.asp.

APPENDIX 2

VAR-002-1 FERC Directives and other Industry Comments

APPENDIX 2 VAR-002-1 FERC Directives and other Industry Comments

STATUS: VAR-002-1 Generator Operation for Maintaining Network Voltage Schedules:

FERC Order 693

Disposition VAR-002-1: Approved

• Consider Dynegy's suggestion to improve the standard.

Phase III/IV comments

• R5 of VAR-002: Recognizing that such action would require the generator to change its loading level or cycle, the transmission operator should not rely on tap position changes on a step-up transformer with a no-load tap changer (NLTC) for periodic or seasonal system control, unless there is an explicit voluntary arrangement with the Generator Operator. For each instance of an urgent directive for such action, the transmission operator must justify its action to affected parties

Standards Process

• Incorporate approved formal interpretation
• Modify standard to conform to the latest version of NERC's Reliability
Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

Relevant FERC Order 693 Paragraphs:

b. VAR-002-1

1881. Reliability Standard VAR-002-1 requires generator operators to operate in automatic voltage control mode, to maintain generator voltage or reactive power output as directed by the transmission operator, and to notify the transmission operator of a change in status or capability of any generator reactive power resource. The Reliability
Standard requires generator owners to provide transmission operators with settings and data for generator step-up transformers. In the NOPR, the Commission stated its belief that Reliability Standard VAR-002-1 is just, reasonable, not unduly discriminatory or preferential and in the public interest; and proposed to approve it as mandatory and enforceable.

i. Comments

1882. APPA and SDG&E agree that VAR-002-1 is sufficient for approval as a mandatory and enforceable Reliability Standard.

1883. Dynegy believes that VAR-002-1 should be modified to require more detailed and definitive requirements when defining the time frame associated with an “incident” of non compliance (i.e., each 4-second scan, 10-minute integrated value, hourly integrated value). Dynegy states that, as written, this Reliability Standard does not define the time frame associated with an “incident” of non-compliance, but apparently leaves this decision to the transmission operator. Dynegy believes that either more detail should be added to the Reliability Standard to cure this omission, or the Reliability Standard should require the transmission operator to have a technical basis for setting the time frame that takes into account system needs and any limitations of the generator. Dynegy believes that this approach will eliminate the potential for undue discrimination and the imposition of overly conservative or excessively wide time frame requirements, both of which could be detrimental to grid reliability.

ii. Commission Determination

1884. In the NOPR, the Commission commended NERC and industry for its efforts in expanding on the Requirements of VAR-002-1 from the predecessor standard, and noted that the submitted Reliability Standard includes Measures and Levels of Non-Compliance to ensure appropriate generation operation to maintain network voltage schedules. Accordingly, the Commission approves Reliability Standard VAR-002-1 as mandatory and enforceable.

1885. Dynegy has suggested an improvement to Reliability Standard VAR-002-1, and NERC should consider this in its Reliability Standards development process.

Interpretation for VAR-002, R1 and R2

Request for Interpretation of NERC Standard VAR-002-1

Dated January 24, 2007
John H. Stout
Mariner Consulting Services, Inc.
1303 Lake Way Drive
Taylor Lake Village, Texas 77586

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R2 goes on to state that each Generation Operator shall maintain the generator voltage ***or Reactive Power output*** as directed by the Transmission Operator.

The two underlined phrases are the reasons for this interpretation request.

Most generation excitation controls include a device known as the Automatic Voltage Regulator, or AVR. This is the device which is referred to by the R1 requirement above. Most AVR's have the option of being set in various operating modes, such as constant voltage, constant power factor, and constant Mvar.

In the course of helping members of the WECC insure that they are in full compliance with NERC Reliability Standards, I have discovered both Transmission Operators and Generation Operators who have interpreted this standard to mean that AVR operation in the constant power factor or constant Mvar modes complies with the R1 and R2 requirements cited above. Their rational is as follows:

- The AVR is clearly in service because it is operating in one of its operating modes
- The AVR is clearly controlling voltage because to maintain constant PF or constant Mvar, it controls the generator terminal voltage
- R2 clearly gives the Transmission Operator the option of directing the Generation Operator to maintain a constant reactive power output rather than a constant voltage.

Other parties have interpreted this standard to require operation in the constant voltage mode only. Their rational stems from the belief that the purpose of the VAR-002-1 standard is to insure the automatic delivery of additional reactive to the system whenever a voltage decline begins to occur.

The material impact of misinterpretation of these standards is twofold.

- First, misinterpretation may result in reduced reactive response during system disturbances, which in turn may contribute to voltage collapse.

- Second, misinterpretation may result in substantial financial penalties imposed on generation operators and transmission operators who believe that they are in full compliance with the standard.

In accordance with the NERC Reliability Standards Development Procedure, I am requesting that a formal interpretation of the VAR-002-1 standard be provided. Two specific questions need to be answered.

- First, does AVR operation in the constant PF or constant Mvar modes comply with R1?
- Second, does R2 give the Transmission Operator the option of directing the Generation Owner to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Interpretation of NERC Standard VAR-002-1
Prepared by Phase 3&4 Standard Drafting Team Members
Dated March 5, 2007

In response to February 2007 request from
John H. Stout
Mariner Consulting Services, Inc.
1303 Lake Way Drive
Taylor Lake Village, Texas 77586

Questions and Answers

The answers to the two questions posed by Mr. John H. Stout are:

1. Question: First, does AVR operation in the constant PF or constant Mvar modes comply with R1?

Answer: No, only operation in constant voltage mode meets this requirement. This answer is predicated on the assumption that the generator has the physical equipment that will allow such operation and that the Transmission Operator has not directed the generator to run in a mode other than constant voltage.

2. Question: Second, does R2 give the Transmission Operator the option of directing the Generation Owner (sic) to operate the AVR in the constant Pf or constant Mvar modes rather than the constant voltage mode?

Answer: Yes, if the Transmission Operator specifically directs a Generator Operator to operate the AVR in a mode other than constant voltage mode, then that directed mode of AVR operation is allowed.

Background and Discussion

Requirement R1 of Standard VAR-002-1 states that Generation Operators shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (***automatic voltage regulator in service and controlling voltage***) unless the Generator Operator has notified the Transmission Operator.

Requirement R1 clearly states controlling voltage. This can only be accomplished by using the automatic voltage control mode. Using the Power Factor (PF) or constant Mvar control is not a true method to control voltage even though they may have some effect on voltage. This is the baseline mode of operation that is clearly conditioned by “unless the Generator Operator has notified the Transmission Operator”. The following Requirement R2 introduces the possibility of an exemption to this baseline mode of operation discussed below.

The above interpretation is further reinforced by reviewing the origin of the requirement. The current Requirement R1 is an evolution of the words in the associated source document, namely NERC Planning Standards Compliance Template for III.C.M1, “Operation of all synchronous generators in the automatic voltage control mode”.

As stated in the original III.C.S1 Standard:

“All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved otherwise by the transmission system operator.”

Requirement R2 of Standard VAR-002-1 goes on to state that “Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings) as directed by the Transmission Operator.” The purpose of this requirement is to give the Transmission Operator the ability to direct the Generator Operator to use another mode of operation. This ability may be necessary based on the Transmission Operator’s system studies and/or knowledge of system conditions. This ability also gives the Transmission Operator the latitude to work with the Generator Operator who has a generating unit that lacks the physical equipment to be able to run in the automatic voltage control mode or has contractual requirements to operate in a certain manner.

Both Requirements R1 and R2 in VAR-002-1 were worded such that they coordinate with Requirement R4 in VAR-001-1:

“Each Transmission Operator shall specify a voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage). “

Again this Requirement R4 reflects that the baseline mode of operation is to use the automatic voltage control mode with the option for the Transmission Operator to specify other modes of operation as dictated by system studies and needs to maintain system reliability.

APPENDIX 3

Functional Entity Definitions

APPENDIX 3 Functional Entity Definitions

Functional Entity Definitions from

Statement of Compliance Registry Criteria

Function Type	Acronym	Definition/Discussion
Balancing Authority	BA	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a BA area, and supports Interconnection frequency in real-time.
Distribution Provider	DP	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the DP. Thus, the DP is not defined by a specific voltage, but rather as performing the Distribution function at any voltage.
Generator Operator	GOP	The entity that operates generating unit(s) and performs the functions of supplying energy and interconnected operations services.
Generator Owner	GO	Entity that owns and maintains generating units.
Interchange Authority	IA	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.
Load-Serving Entity	LSE	Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.
Planning Coordinator	PC	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

Function Type	Acronym	Definition/Discussion
Purchasing-Selling Entity	PSE	The entity that purchases or sells and takes title to energy, capacity, and interconnected operations services. PSE may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Reliability Coordinator	RC	The entity that is the highest level of authority who is responsible for the reliable operation of the bulk power system, has the wide area view of the bulk power system, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of interconnection reliability operating limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reserve Sharing Group	RSG	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each BA's use in recovering from contingencies within the group. Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker, (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a RSG.
Resource Planner	RP	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a PC area.
Transmission Owner	TO	The entity that owns and maintains transmission facilities.
Transmission Operator	TOP	The entity responsible for the reliability of its local transmission system and operates or directs the operations of the transmission facilities.

Function Type	Acronym	Definition/Discussion
Transmission Planner	TP	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PC area.
Transmission Service Provider	TSP	The entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

APPENDIX 4

Reactive Support and Control Basics

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Reactive Support and Control Basics

March 17-18, 2009

TIS-Reactive Support/Control Subteam
presentation to NERC PC

to ensure the reliability of the bulk power system

Presentation Outline

- Why do you and I care about VARs?
- NERC Interconnections
- Conservation of AC Reactive Energy
- AC Reactive Physics
- What’s next?

Why do you and I care about VARs?

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- Each power plant and end use customer connects to ONE synchronous 'Interconnection'.
    - Generation Owner (GO), Transmission Owner(TO), and Transmission Operator (TOP) control rooms are integrated by their Reliability Coordinator (RC)
    - These RCs jointly manage & direct their 'Interconnection'
    - The 'Interconnection' is one synchronous system with only DC connections to other 'Interconnections'
    - Each 'Interconnection' has zero VAR reactive energy interchange

Why do you and I care about VARs?

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- Prior to a forced facility outage;
  - (1) TOP control centers must be ***able to predict power plant unit response*** (MW, VAR, and voltage) both during and after the event.
  - (2) Power plants must be able to predict the plant's response to voltages that are below schedule or below design minimums.
    - – Will Automatic Voltage Regulator (AVR) trip from automatic to a predictable manual VAR output? or after several minutes, will AVR control VAR output to rated maximum VAR output?
    - – Due to lower voltage on plant auxiliary equipment, will plant motor controls, feeders, or motors trip on under-voltage protection? Aux bus voltage impacts vary depending on the source bus (generator terminal or system bus) voltage control.
    - – Will the generator trip due to the above control actions including turbine control response? Will nuclear plant degraded grid voltage relays shut down one or more units?

Why do you and I care about VARs?

- ***Planning for the future is critical***
  - Planning Coordinator (PC), Transmission Planner(TP), Transmission Owner(TO), Generation Owners (GO), and Distribution Providers(DP) need to predict future reactive sources, loads, losses and any resulting VAR deficiencies.
  - LSEs and PSEs must provide accurate forecasts of demand
  - Planning lead time is critical to identify reactive deficiencies, budget, and install reactive sources.   The PC needs to coordinate the overall plan with all entities involved.

Why do you and I care about VARs?

- System performance must be within applicable TPL performance requirements. As built facility data is a must.
- TP, PC, RC, TOP, & GOP must be able to accurately predict combined transmission and generation system response.
- Adhering to system performance requirements in the planning and operational time frame are in the mutual best interest for all entities to maintain reliability and prevent permanent equipment damage.

Why do you and I care about VARs?

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

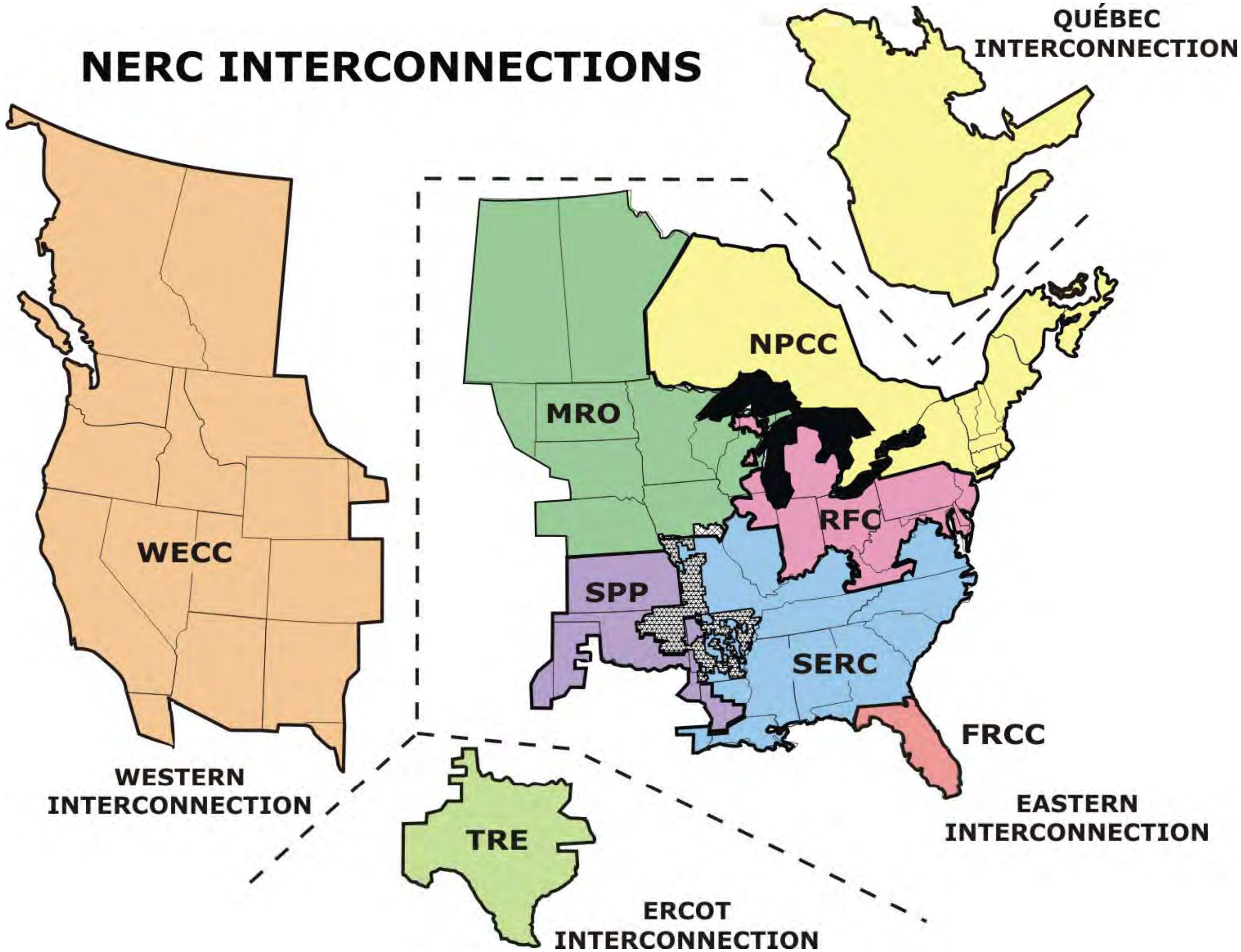
- Facilities must be operated within equipment ratings.
  - Overloads must be eliminated, OR equipment manually or automatically taken out of service prior to permanent damage.
- Permanent facility damage jeopardizes system capability to restore load.
  - Permanent damage can be caused by high voltage or ampere overloads resulting from low voltage.

Why do you and I care about VARs?

- Reliability Coordinator (**RC**), Transmission Operator (**TOP**), and Generation Operator (**GOP**) **must**;
    - Coordinate data collection to support daily operation and operations planning
    - review medium range operational plans
    - review longer range design & construction
    - jointly execute the operational plan.
- Long range planning must provide the **capability** to operate the system as intended

NERC Interconnections

'Interconnections' connected by DC ties



NERC Regions

- FRCC (Florida Reliability Coordinating Council)
- MRO (Midwest Reliability Organization)
- NPCC (Northeast Power Coordinating Council)
- RFC (Reliability*First* Corp)
- SERC (SERC, Inc.)
- SPP (Southwest Power Pool)
- ERCOT / TRE (Electric Reliability Council of Texas / Texas Regional Entity)
- WECC (Western Electricity Coordinating Council)

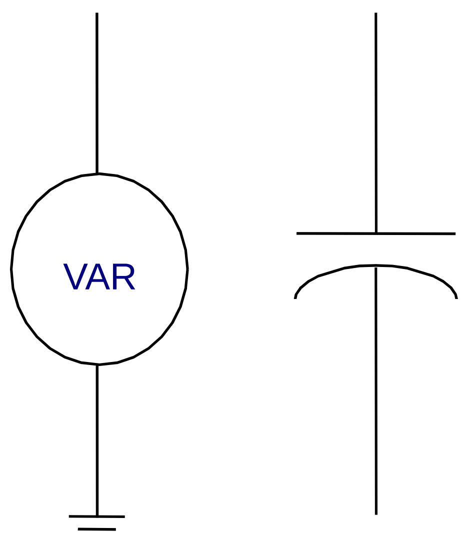
NERC Interconnections

- Interconnections connected by DC ties
- Laws of Reactive Physics:
  - No AC network tie lines between Interconnections
  - MW interchange exists on DC tie lines
  - Zero VAR interchange between Interconnections
    - Interconnection operates at unity Power Factor
    - 100% conservation of Reactive Energy
- Definition of terms is next . . . .

Conservation of Reactive Energy: VAR Consumption MUST EQUAL Production

Reactive Energy **Production:**

Generation, and Capacitance Devices



Static Capacitors
Line Charging, etc.

=

Reactive Energy **Consumption:**

Delivery Losses

$I^2 * X$

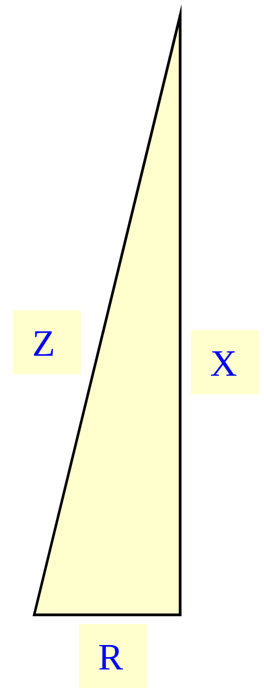
plus

Customer VAR demand

~ 85 to 95% Power Factor, customer reactive compensation (if any), demand side management, etc.

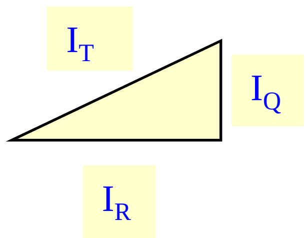
Laws of Reactive Physics

- **V = I * Z**
  - V is voltage phasor
  - I is current phasor
  - Z is impedance, comprised of resistance R and reactance X
    - R and X are 90° out of phase



Laws of Reactive Physics

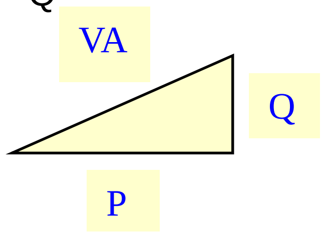
- System load is comprised of resistive current (such as lights, space heaters) and reactive current (induction motor reactance, etc)
- Total current I_T has two components
  - » I_R resistive current
  - » I_Q reactive current
  - » I_T is the vector sum of I_R & I_Q ;
  - » $I_T = I_R + j\, I_Q$



Laws of Reactive Physics

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

- Complex Power called Volt Amperes ("VA") comprised of resistive current I_R and reactive current I_Q times the voltage.



  » "VA" = VI_T^* = $V(I_R - j\,I_Q)$ = $P + j\,Q$

- Power Factor ("PF") = Cosine of angle between P & "VA" P = "VA" times "PF"

- System losses

  » $P_{loss} = I_T^2\,R$ (Watts)

  » $Q_{loss} = I_T^2\,X$ (VARs)

Reactive Physics – VAR loss

- Every component with reactance, X : VAR loss = I_T^2 X
- Z is comprised of resistance R and reactance X
  - on 138kv lines, X = 2 to 5 times larger than R
  - on 230kv lines, X = 5 to 10 times larger than R
  - on 500kv lines, X = 25 times larger than R
  - R decreases when conductor diameter increases. X increases as the required geometry of phase to phase spacing increases.
- VAR loss
  - increases in proportion to square of total current
  - is approximately 2 to 25 times larger than Watt loss

Reactive Physics – Tap Changers

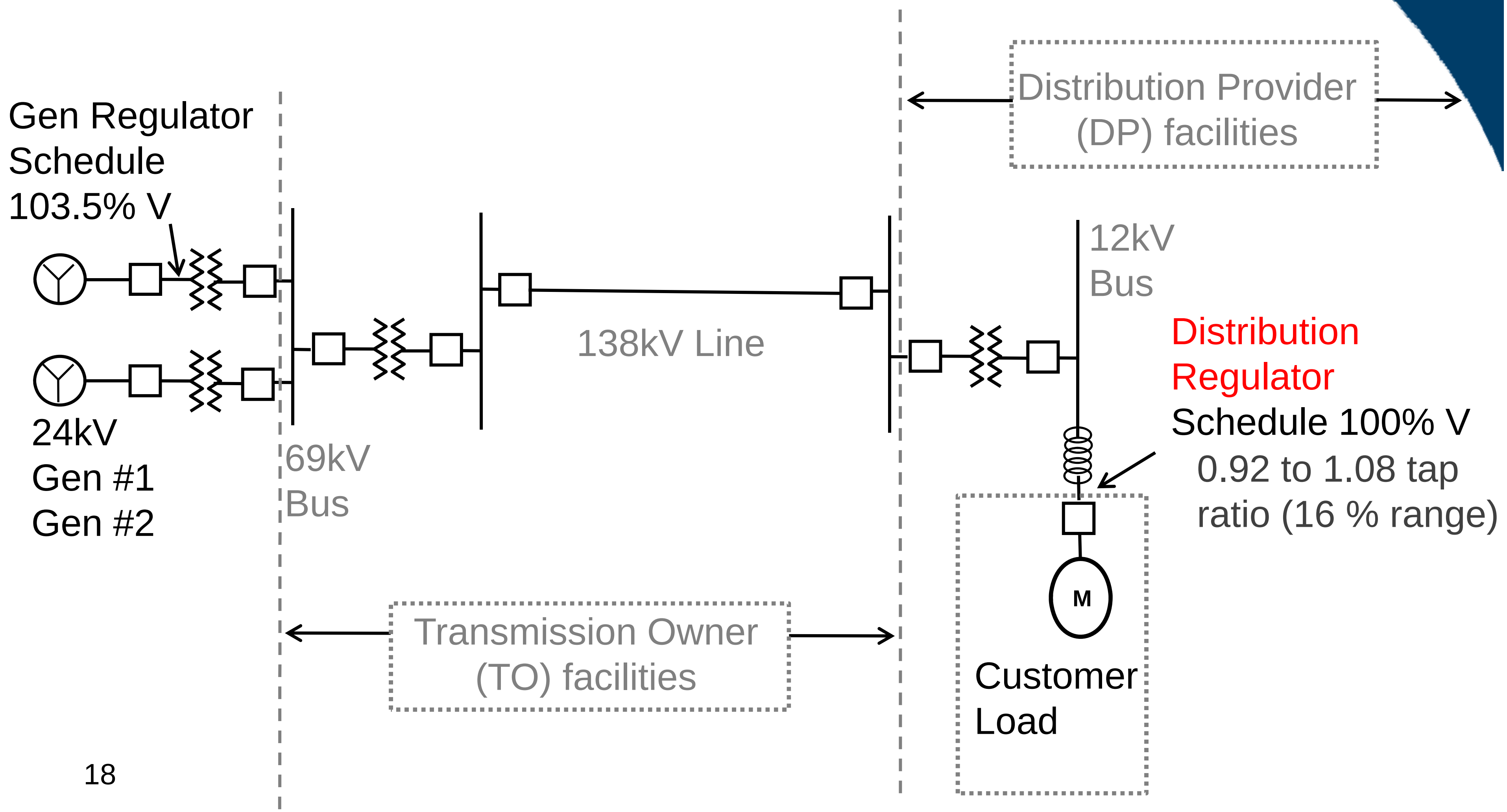
- Transformer Automatic Tap Changers and Distribution Voltage Regulators
  - Do not produce VARs, but can pull and push VARs toward customer load
  - “Boost tap change” pulls VARs from system source side and pushes VARs toward load.
- IF distant VAR sources exist, tap changer source side voltage decreases and load side voltage increases.
  - To maintain load side voltage the tap changer can significantly lower the source side voltage even for a very small increase in load. (The voltage on the source side could collapse).

Reactive Physics – Tap Changers

- IF source VARs do NOT exist, VAR flow will not increase.
  - Automatic tap changer will 'boost' to high limit tap in an attempt to maintain load side voltage.
  - The source side voltage may collapse
- The above behavior can be modeled only if adequate data is documented and made available.
- The above can be predicted only if reactive forecasts and models are provided by all the functional entities involved (GOs, TOs, DPs, LSEs, PSEs, etc).

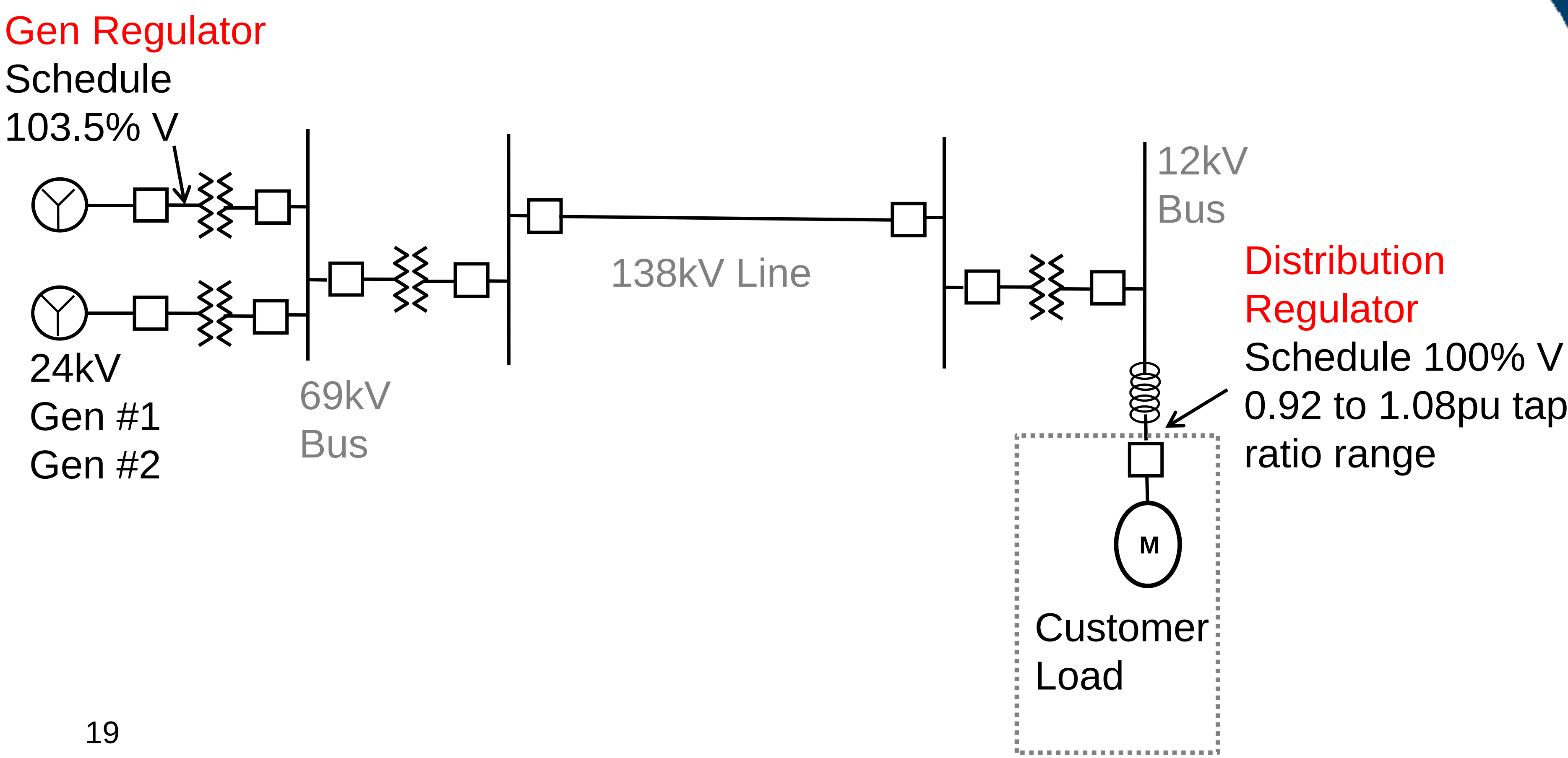
Reactive Physics – Tap Changers

- Distribution Voltage Regulator



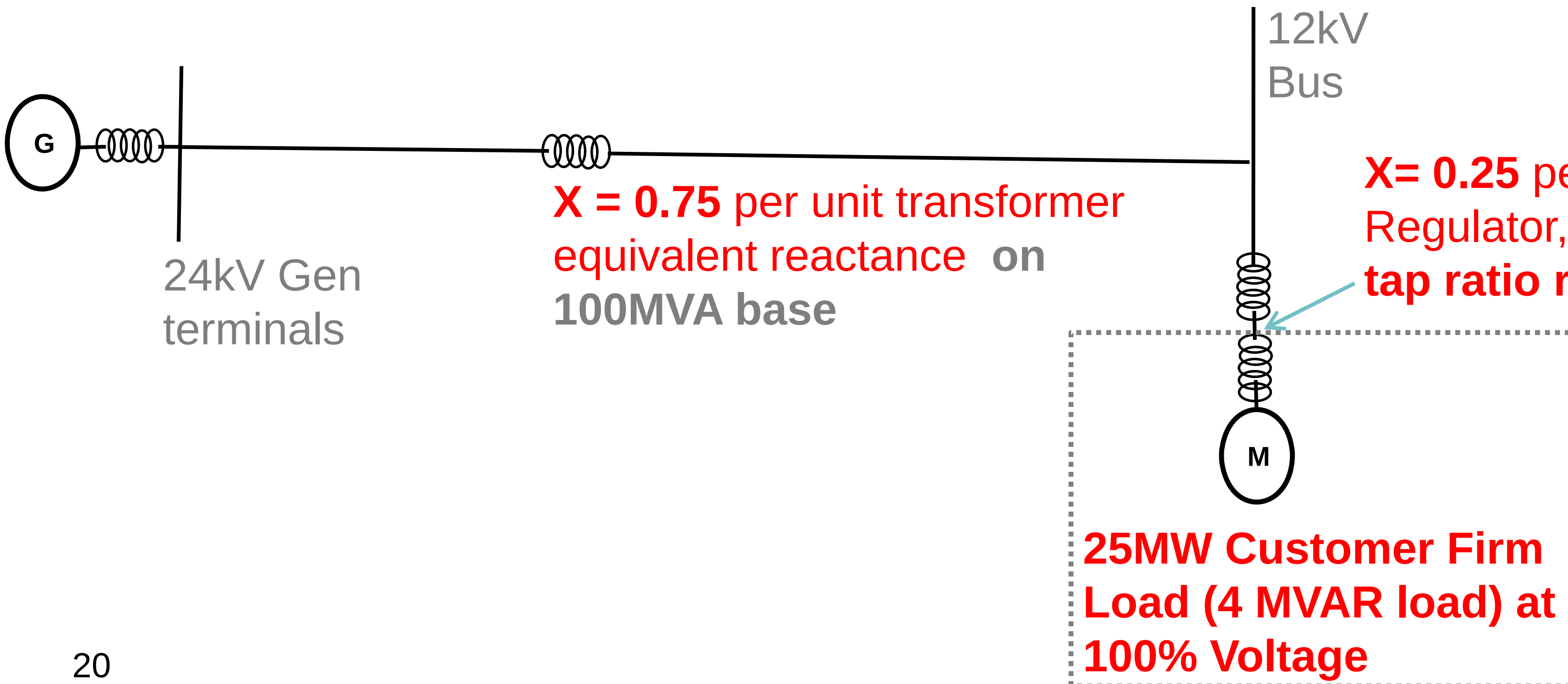
Reactive Physics – Tap Changers

- Distribution Voltage Regulator - EXAMPLE
  - **Example A:** "Boost tap change" with insufficient VAR sources.



Reactive Physics – Example A

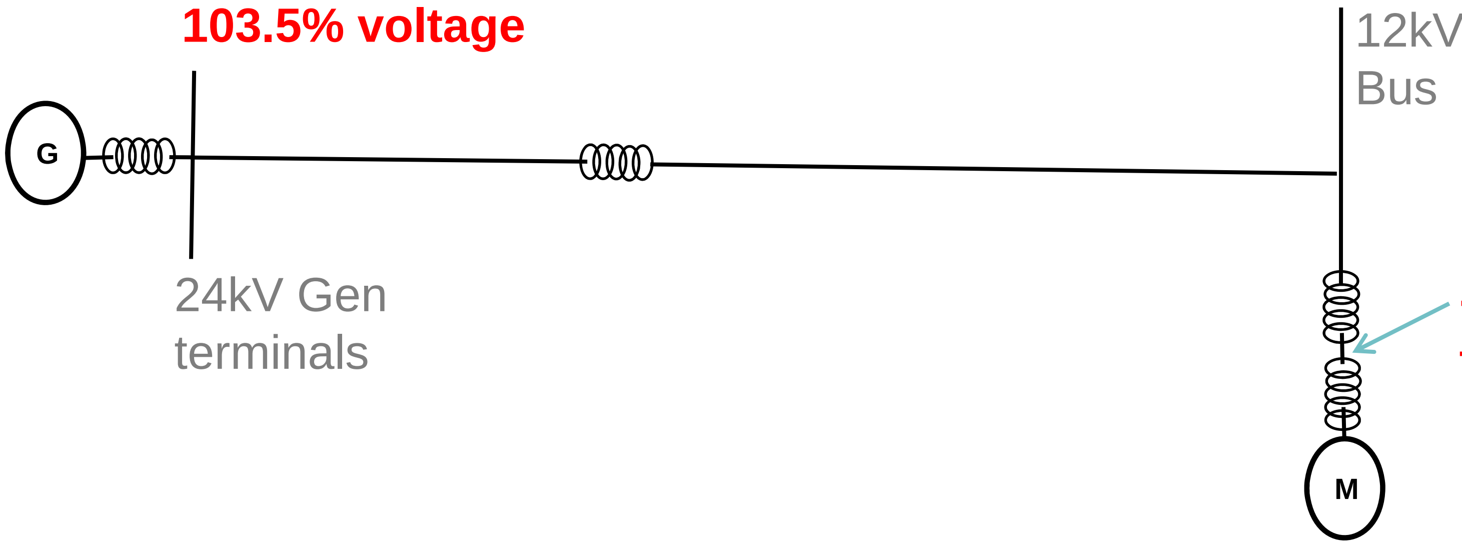
25MW Generator capacity (PSE or LSE firm contract)
(27.8 MVA nameplate, at 90% rated power factor)



Reactive Physics – Example A

Step 1, time = 0 seconds
<u>Initial Conditions</u>

25MW, 10.95 MVAR
Generator output at
103.5% voltage

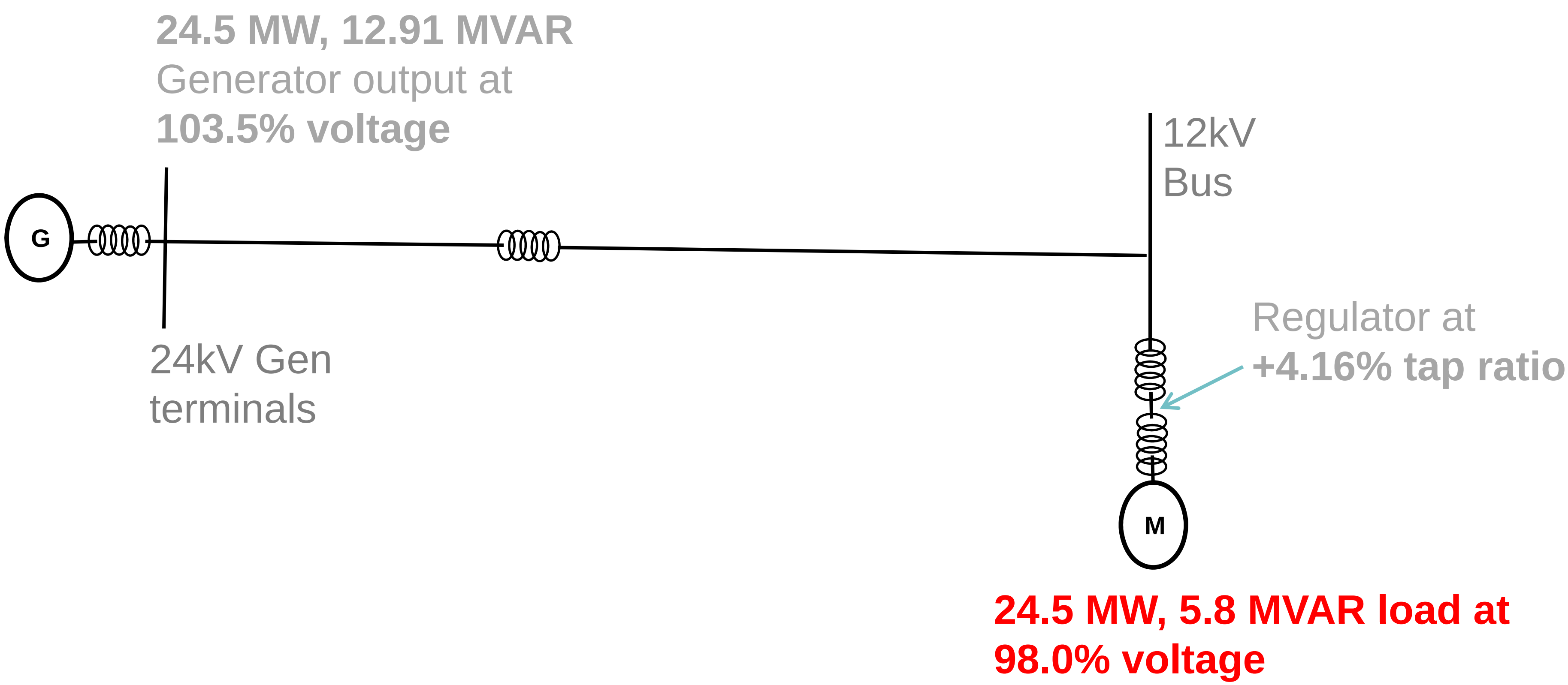


Regulator at
+4.16% tap ratio
to hold 100% V

25MW, 4 MVAR
(Transient load model: constant current MW, constant impedance MVAR)

Reactive Physics – Example A

Step 2, time = 1 to 5 seconds
Sudden Increase in Customer MVAR demand;
Generator AVR responds to hold voltage at generator terminals



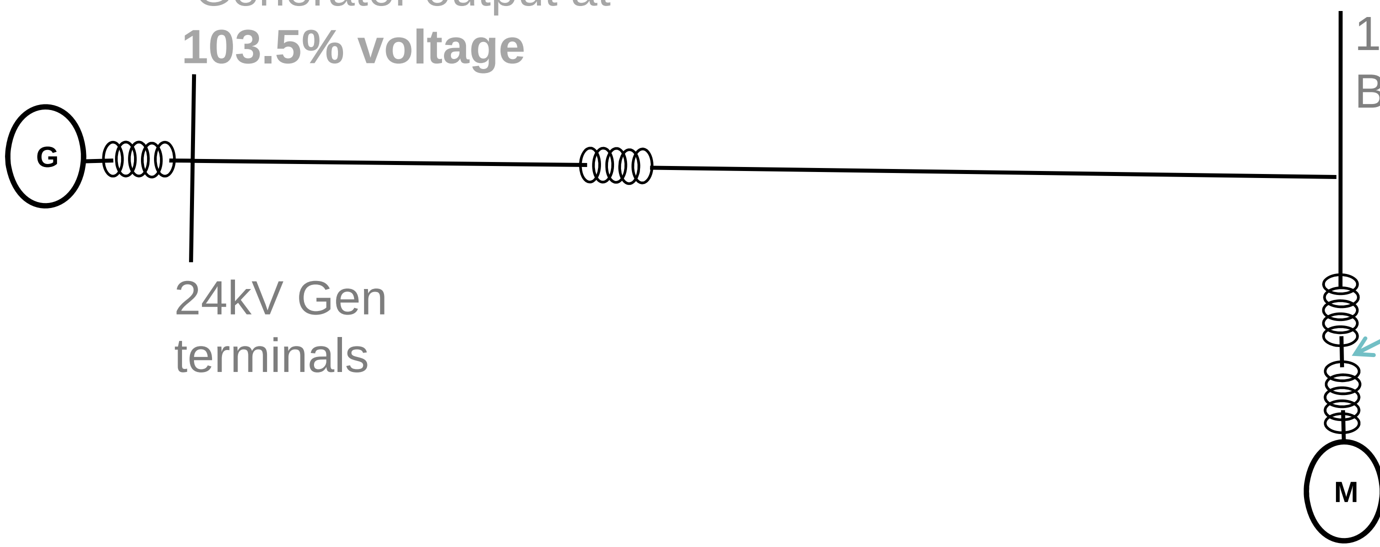
Reactive Physics – Example A

Step 3, time = 15 to 30 seconds
<u>Regulator 'Boosts Tap' ratio </u>after 15-30 second delay to 100% V.

25 MW, 13.55 MVAR (0.275pu stator Current)
(12.1 MVAR rotor Rating, 0.278pu stator Current Rating)

Generator output at
103.5% voltage

12kV
Bus



24kV Gen
terminals

Regulator at
+6.86% tap ratio,
100% voltage
schedule

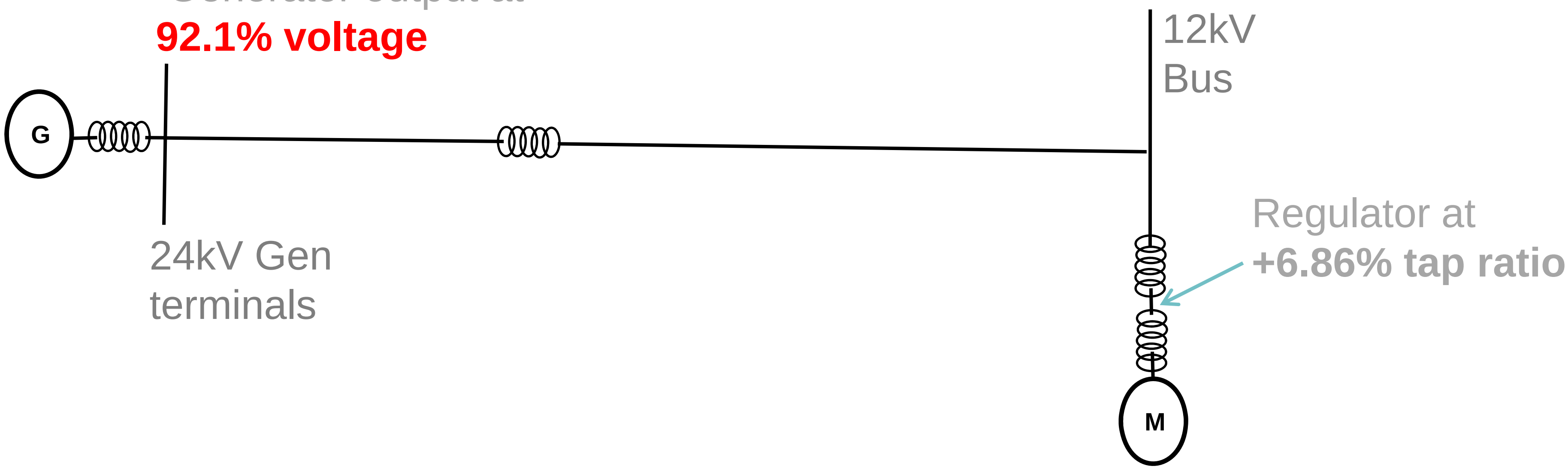
25 MW, 6 MVAR load at
100% voltage

Reactive Physics – Example A

Step 4, time = 2 to 5 minutes
Gen. Operator (GOP) limits MVARs to rotor Rating by decreasing AVR setting (& decreases DC field current).

22 MW, **12.1 MVAR (0.273pu stator Current)**
(12.1 MVAR rotor Rating, 0.278pu stator Current Rating)

Generator output at
92.1% voltage

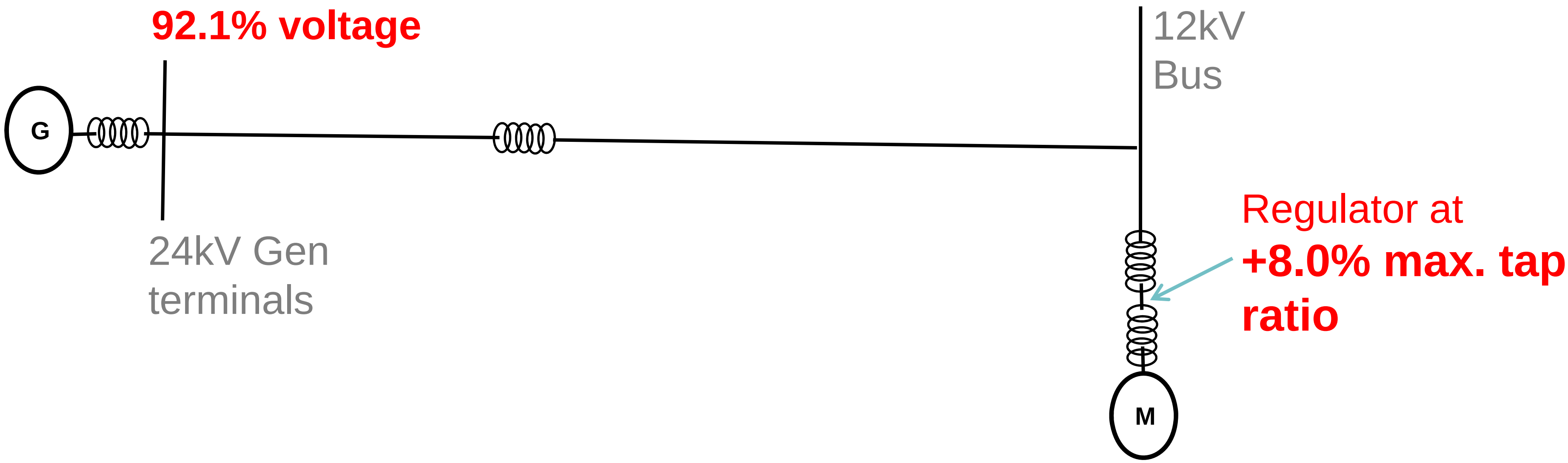


22 MW, 4.7 MVAR load at
88.1% voltage

Reactive Physics – Example A

Step 5, time = 5 to 15 minutes (after GOP action)
Regulator boosts to maximum tap ratio 108%.
Due to sustained low voltage, TOP operator trips Firm load to prevent permanent damage to customer equipment.

22.2 MW, 12.4 MVAR (0.276pu stator Current)
(12.1 MVAR rotor Rating, 0.278pu stator Current Rating)
92.1% voltage



22.2 MW, 4.7 MVAR load at
88.8% voltage

Reactive Physics – Example A

- **Example A:** maximum "Boost tap change" **with insufficient VAR sources.**
- VAR flow must not exceed generator rating for a long period of time. GOP must take action to prevent permanent damage to equipment.
- After GOP return to MVAR rated output, T&D system voltage may collapse. Customer voltage may collapse. TOP may need to trip Firm customer load.
- Conservation of Reactive Energy is important
  - Customer Demand Side Management (DSM) for non-firm loads may be used
  - Reactive Sources must meet Customer Firm demand plus system reactive energy losses

Reactive Physics – Voltage Change Example #1

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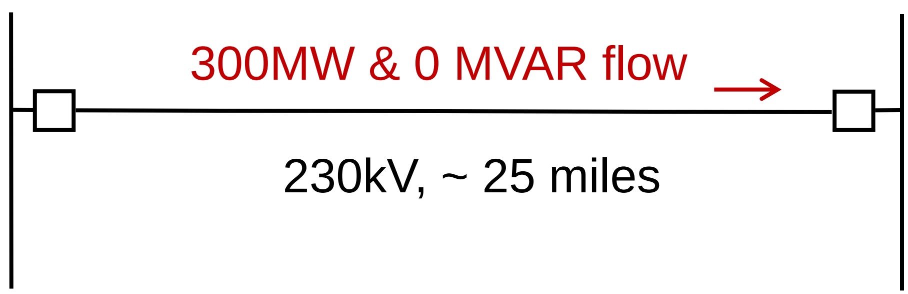
- What causes the most $\mathbf{V_{drop}}$? MWs or VARs?
- Example: ~25 mile 230kV line; Z = 0.005pu +j 0.04pu on 100MVA Base.
- Given 95% receiving end voltage with 300 MW & 0MVAR flow (300 MVA).



97.4% Voltage

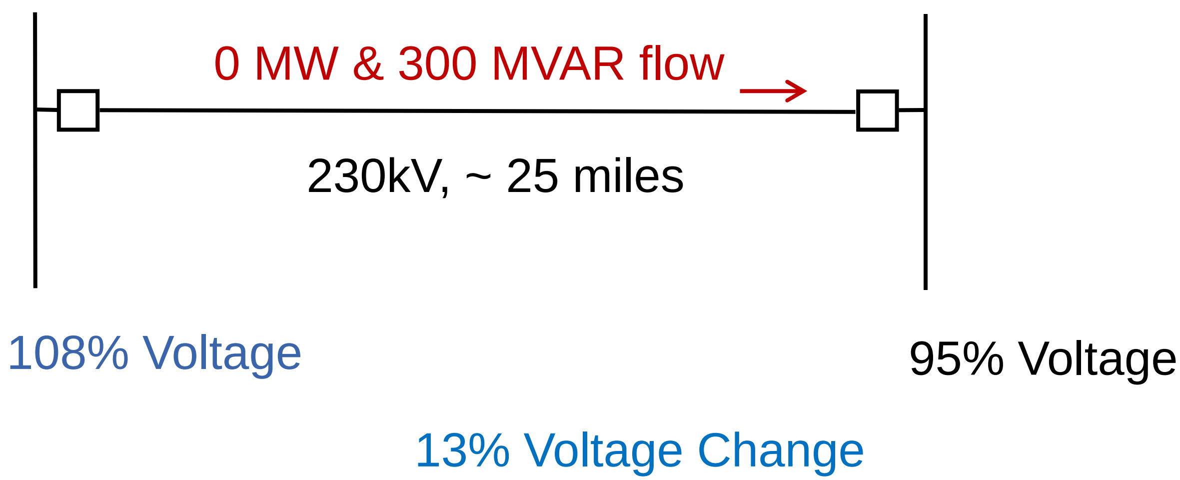
95% Voltage

2.4% Voltage Change

Reactive Physics – Voltage Change Example #2

- **Example #2: VAR flow** causes most of the $\mathbf{V_{drop}}$

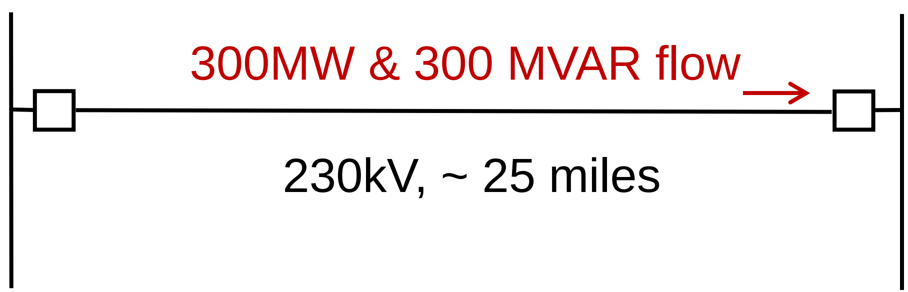
  Given 95% receiving end voltage with 0 MW & 300MVAR flow (300 MVA).



Reactive Physics – Voltage Change Example #3

- Example #3: VAR flow causes more V_{drop} than MW

  Given 95% receiving end voltage with 300 MW & 300MVAR flow (424 MVA).



110% Voltage

95% Voltage

15% Voltage Change

Reactive Physics – Voltage Change Example #1,2,3 SUMMARY

- Example #1: 300 MW flow
  - Vdrop = 97.4% - 95% = 2.4%
  - Approx. Vdrop = PR + QX = 3.05*0.005+0.399*0.04 = 0.03 ~ 3%
- Example #2: 300 MVAR flow
  - Vdrop = 108% - 95% = 13%
  - Approx Vdrop = PR + QX = 0.05*0.005 + 3.4*0.04 = 0.136 ~ 13.6%
- Example #3: 300 MW & 300 MVAR
  - Vdrop = 110% - 95% = 15%
  - Approx. Vdrop = PR + QX = 3.1*0.005 + 3.8*0.04 = 0.16 ~ 16%
- **Approx. Voltage Change = PR + QX**
  - **X is 5 to 25 times larger than R**
- **VARs can not travel too far due to large V change**

Reactive Physics – VAR Sharing

- Electricity is a unique service
  - **Cannot be inventoried** at a level demanded by customers. The ultimate "just-in-time**"** manufacturing system.
- MWs and ***VARs*** are "just-in-time" services.
- MWs can be transmitted over longer distances than VARs
- **VARs can NOT be transmitted over long distances due to relatively high X.** If attempted, large V drops occur
- Conservation of Reactive Energy is important

Presentation Outline

- Why do you and I care about VARs?
- NERC Interconnections
- Conservation of AC Reactive Energy
- AC Reactive Physics
- What's next?
  - Project 2008-1 Voltage and Reactive - Scope

APPENDIX 5

Functional Entities Involved by System State Time Frame

APPENDIX 5 - Functional Entities involved by System State Time Frame

VAR/Voltage related: Functional Entity existing requirements by System State Time Frame

System State - Time Frame	LSE	PSE	DP	GO	RP	TO & TP	RRO	PC	GOP	TOP	RC
Time = 0: Normal Steady State	x	x	x	x	x	x		x	x	x	x
		VAR-1-1a_R5		LGIA, FAC-001					VAR-2-1a_R1	VAR-1-1a_R1	
		MOD	MOD	MOD-11-0_R1	MOD-11-0_R1	MOD-11-0_R1	MOD-11-0_R1		VAR-2-1a_R2	VAR-1-1a_R2	
				FAC-1-0_R2.1.3		FAC-1-0_R2.1.3	MOD-14-0_R1		VAR-2-1a_R3	VAR-1-1a_R3	
				FAC-1-0_R2.1.9		FAC-1-0_R2.1.9	MOD-16-0_R?	MOD-16-0_R?		VAR-1-1a_R4	
	FAC-2-0_R1		FAC-2-0_R1	FAC-2-0_R1		FAC-2-0_R1		FAC-2-0_R1			
	MOD-17-0_R?			VAR-2-1a_R4	MOD-17-0_R?	MOD-17-0_R?		MOD-17-0_R?		VAR-1-1a_R6	
	MOD-18-0_R?			VAR-2-1a_R5	MOD-18-0_R?	MOD-18-0_R?		MOD-18-0_R?		VAR-1-1a_R7	
	MOD-19-0_R?				MOD-19-0_R?	MOD-19-0_R?		MOD-19-0_R?		VAR-1-1a_R8	
	MOD-20-0_R?			VAR-1-1a_R11?	MOD-20-0_R?	MOD-20-0_R?		FAC-10-2_R2.1		VAR-1-1a_R11	FAC-11-2_R2.1
	MOD-21-0_R?				MOD-21-0_R?	MOD-21-0_R?		FAC-14-2_R3		FAC-010 & 011	FAC-14-2_R1
						FAC-14-2_R4				FAC-14-2_R2	
										TOP-002-2_R1	
						TPL-001-0_R1.3.9	TPL-006-0_R1	TPL-001-0_R1.3.9		TOP-002-2_R2	
										TOP-002-2_R11	
									TOP-002-2_R13	TOP-002-2_R13	
										TOP-003-0_R1.2	
									TOP-003-0_R2	TOP-003-0_R2	
										TOP-004-2_R4	
										TOP-004-2_R6.1	
									TOP-005-1_R1.2	TOP-005-1_R1.2	
										TOP-006-1_R2	
Time = 0 to 3 seconds: Transient				x	X	x		x	x	x	x
	NA	NA	NA	MOD-12-0_R1	MOD-12-0_R1	MOD-12-0_R1	MOD-12-0_R1	FAC-10-2_R2.2			FAC-11-2_R2.2
				PRC-24-SAR work		TPL-002-1	MOD-15-0_R1				
						TPL-003-1					
Time = 3 to 30 seconds: Post Transient Dynamic				x		x		x	x	x	x
	NA	NA	NA	MOD-12-0_R1	MOD-12-0_R1	MOD-12-0_R1	MOD-12-0_R1	FAC-10-2_R2.2			FAC-11-2_R2.2
				PRC-24-SAR work		TPL-002-1	MOD-15-0_R1			VAR-1-1a_R9	
						TPL-003-1					
Time = 30 seconds to 3 minutes: Post Transient Static				x		x		x	x	x	x
	EOP-003-1_R??	EOP-003-1_R??	EOP-003-1_R??	MOD-11-0_R1	MOD-11-0_R1	MOD-11-0_R1	MOD-11-0_R1	MOD			
							MOD-14-0_R1	FAC-10-2_R2.2			FAC-11-2_R2.2
						FAC-14-2_R4		FAC-14-2_R3		FAC-14-2_R2	FAC-14-2_R1
										TOP-004-2_R4	
						TPL-002-0_R1.3.9	TPL-006-0_R1	TPL-002-0_R1.3.9		TOP-004-2_R6.1	
						TPL-003-0_R1.3.9		TPL-003-0_R1.3.9	TOP-005-1_R1.2	TOP-005-1_R1.2	
						TPL-004-0_R1.3.6		TPL-003-0_R1.3.6		TOP-006-1_R2	
										TOP-007-0_R1	
										TOP-007-0_R2	
										TOP-007-0_R3	
										TOP-008-1_R1	
										TOP-008-1_R2	
										TOP-008-1_R3	
										TOP-008-1_R4	
										EOP-001-0_R4.2	
										EOP-003-1_R3,4&7	

Time = 3 to 30 minutes: Emergency Steady State		x	x	x		x		x	x	x	x
	EOP-003-1_R??	EOP-003-1_R??	EOP-003-1_R??	MOD-11-0_R1	MOD-11-0_R1	MOD-11-0_R1	MOD-11-0_R1	FAC-10-2_R2.2	VAR-2-1a_R2.2	VAR-1-1a_R1	FAC-11-2_R2.2
				EOP??		TPL-002-1	MOD-14-0_R1	FAC-14-2_R3		VAR-1-1a_R2	FAC-14-2_R1
						TPL-003-1				VAR-1-1a_R9	
						FAC-14-2_R4				VAR-1-1a_R10	
										VAR-1-1a_R12	
						TPL-002-0_R1.3.9	TPL-006-0_R1	TPL-002-0_R1.3.9		FAC-14-2_R2	
						TPL-003-0_R1.3.9		TPL-003-0_R1.3.9		TOP-004-2_R4	
						TPL-004-0_R1.3.6		TPL-003-0_R1.3.6		TOP-004-2_R6.1	
									TOP-005-1_R1.2	TOP-005-1_R1.2	
										TOP-006-1_R2	
										TOP-007-0_R1	
										TOP-007-0_R2	
										TOP-007-0_R3	
										TOP-007-0_R4	
										TOP-008-1_R1	
										TOP-008-1_R2	
										TOP-008-1_R3	
										TOP-008-1_R4	
										EOP-001-0_R4.2	
										EOP-003-1_R3,4&7	

Notes & Abbreviations:

LGIA = Large Generator Interconnection Agreement issued by FERC 3/5/2004 in Docket#: RM02-1-001

NA = Not applicable, no Requirements

Rev. 5-12-09

SEE NEXT SHEET

DESIRED Coverage

Rev. 5/12/2009

System State - Time Frame	LSE	PSE	DP	GO	RP	TO & TP	RRO	PC	GOP	TOP	RC
Time 0 -- Normal Steady State (pre-contingency)	x	x	x	x	x	x	x	x	x	x	x
5 yr Planning	PEAK MW PERIOD HISTORY (provide history data to DP, TP, RRO, & PA)	PEAK MW PERIOD HISTORY (provide Firm Transaction history data to DP, TP, RRO, & PA)	TO/DP interface(s) MW & MVAR Load Forecast (based on interface annual history plus LSE & PSE specific 5yr. New loads)	Firm and Non-Firm Resource Model parameters	MW Resource Firm and Non-Firm MW & MVAR Forecast	TO Bus Model MW & MVAR Load Forecast (based on history, DP, LSE & PSE specific 5yr. Info.)	Model coordination	Grand Total Peak MW & MVAR Demand Forecast (with & w/o DSM Firm Plans)	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments
	Network Firm MW Peak Load Forecast within 5yr plan for TP & DP use	FIRM MW Transaction Contracts within 5yr plan for TP & DP use	Budget Facilities	Budget Facilities	Reactive Resource Forecast	Model parameters		Coor overall Plan including "Reactive Energy Conservation" protocol			
	Specific Significant MW (& MVAR) Load Changes within 5yrs	Specific Significant MW (& MVAR) Load Changes within 5yrs	Prepare Underfrequency or Undervoltage Relay (if any) Load Shed settings on Distribution Feeders	Abide by LGIA. Other existing units abide by existing design limitations		5yr Facility Construction Plan		Coor "Base Case" Scheduled AVR Voltage (or PF) Settings			
	DSM MW (& MVAR) FIRM plans	DSM MW (& MVAR) FIRM plans		Equipment PROTECTION to prevent permanent damage		Determine "Base Case" Scheduled AVR Voltage (or PF) and GSU No Load TAP Settings		Coor "Normal Minimum Scheduled Bus V-Limits"			
				Coordinate GOP Control Equipment Settings with BES system emergency response		Establish "Normal Minimum Scheduled Bus V-Limits"		Coor overall Plan including "Voltage Regulation/ Collapse Safety Margin" protocol			
Operations Planning - 1Yr	Load Forecast & PF	FIRM Transaction Forecast PF	Load Forecast at TO/DP interface	Model parameters	Reactive Resource Forecast	Model parameters	NA	Coor overall Plan	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments
	Review Emergency EOP Plans	Review Emergency EOP Plans	Apply Underfrequency or Undervoltage Relay (if any) Load Shed settings on Distribution Feeders	Coordinate GOP Control Equipment Settings with BES system emergency response		Determine "Base Case" Scheduled AVR Voltage (or PF) and GSU No Load TAP Settings		Coor "Normal Minimum Scheduled Bus V-Limits"	Apply AVR Voltage (or PF) Settings, and GSU Tap settings	Finalize "Base Case" Scheduled AVR Voltage (or PF) and GSU No Load TAP Settings	Coor "Base Case" Scheduled AVR Voltage (or PF) Settings

	DSM MW & MVAR	DSM MW & MVAR				Establish "Normal Minimum Scheduled Bus V-Limits"		Coor overall Plan including "Voltage Regulation/Collapse Safety Margin" protocol	Finalize "Normal Bandwidth of Scheduled Bus V-Limits"	Finalize "Normal Bandwidth of Scheduled Bus V-Limits"	Coor "Normal Bandwidth of Scheduled Bus V-Limits"
								Coor "Base Case" Scheduled AVR Voltage (or PF) Settings		"Normal Minimum Reactive Margin"	Coordinate "Normal Minimum Reactive Margin"
Operations Planning Short Range (1 week)	Prepare Weekly/Daily Load Forecast	Prepare Weekly/Daily Transaction Forecast	NA	NA	NA	NA	NA	NA	Prepare Weekly/ Daily Resource Availability Forecast	Prepare Weekly/ Daily Resource Availability Forecast	Prepare Weekly/ Daily Resource Availability Forecast
	DSM MW & MVAR	DSM MW & MVAR									Coor adjustments based on "Normal Minimum Scheduled Bus V-Limits"
											Establish Short Range (1 week) FAC limits, IROL limits, etc
Time = 0 to 3 seconds: Transient	**NA**	**NA**	**NA**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
5 yr Planning	NA	NA	NA			Perform TPL Standard required dynamic tests and document identified limitations		Coordinate TPL Standard required dynamic tests and documentation	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments
Operations Planning - 1Yr	NA	NA	NA			Same as above		Same as above		Same as above	Same as above
Operations Planning Short Range (1 week)	NA	NA	NA	NA	NA	NA	NA	NA		Establish Short Range (1 week) FAC limits, IROL limits, etc	Establish Short Range (1 week) FAC limits, IROL limits, etc
Time = 3 to 30 seconds: Post Transient Dynamic	**NA**	**NA**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
5 yr Planning	NA	NA	NA			Same as above		Same as above	Same as above	Same as above	Same as above
Operations Planning - 1Yr	NA	NA	NA			Same as above		Same as above	Same as above	Same as above	Same as above
Operations Planning Short Range (1 week)	NA	NA	NA	NA	NA	NA	NA	NA		Same as above	Same as above

Time = 30 seconds to 3 minutes: Post Transient Static	**NA**	**NA**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
5 yr Planning	NA	NA				Perform TPL Standard required LOAD FLOW analysis and document identified limitations		Coordinate TPL Standard required LOAD FLOW analysis and document identified limitations	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments
Operations Planning - 1Yr	NA	NA				Perform TPL Standard required LOAD FLOW analysis and document identified limitations		Coordinate TPL Standard required LOAD FLOW analysis and document identified limitations	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments
Operations Planning - 1 Wk	NA	NA	NA	NA	NA	NA	NA	NA		Establish Short Range (1 week) FAC limits, IROL limits, etc	Establish Short Range (1week) FAC limits, IROL limits, etc
Time = 3 to 30 minutes: Emergency Steady State	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**	**X**
5 yr Planning	DSM MW & MVAR	DSM MW & MVAR				Perform TPL Standard required Load Flow analysis and document identified limitations		Coordinate TPL Standard required Load Flow analysis and document identified limitations	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments	Review PA/PC Plans and provide Comments
Operations Planning - 1Yr	DSM MW & MVAR	DSM MW & MVAR				Perform TPL Standard required Load Flow analysis and document identified limitations		Coordinate TPL Standard required Load Flow analysis and document identified limitations	Establish EOP Protocols	Establish EOP Protocols	Coordinate EOP Protocols
Operations Planning - 1 Wk	NA	NA	NA	NA	NA	NA	NA	NA		Establish Short Range (1 week) FAC limits, IROL limits, etc	Establish Short Range (1 week) FAC limits, IROL limits, etc

NA = Not applicable, no Requirements

Appendix 6

Functional Entity Mapping for Reactive Planning

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Functional Entity Mapping For Reactive Planning

Rev. 5/12/2009

to ensure the reliability of the bulk power system

APPENDIX 6

Functional Entity Mapping For Reactive Planning

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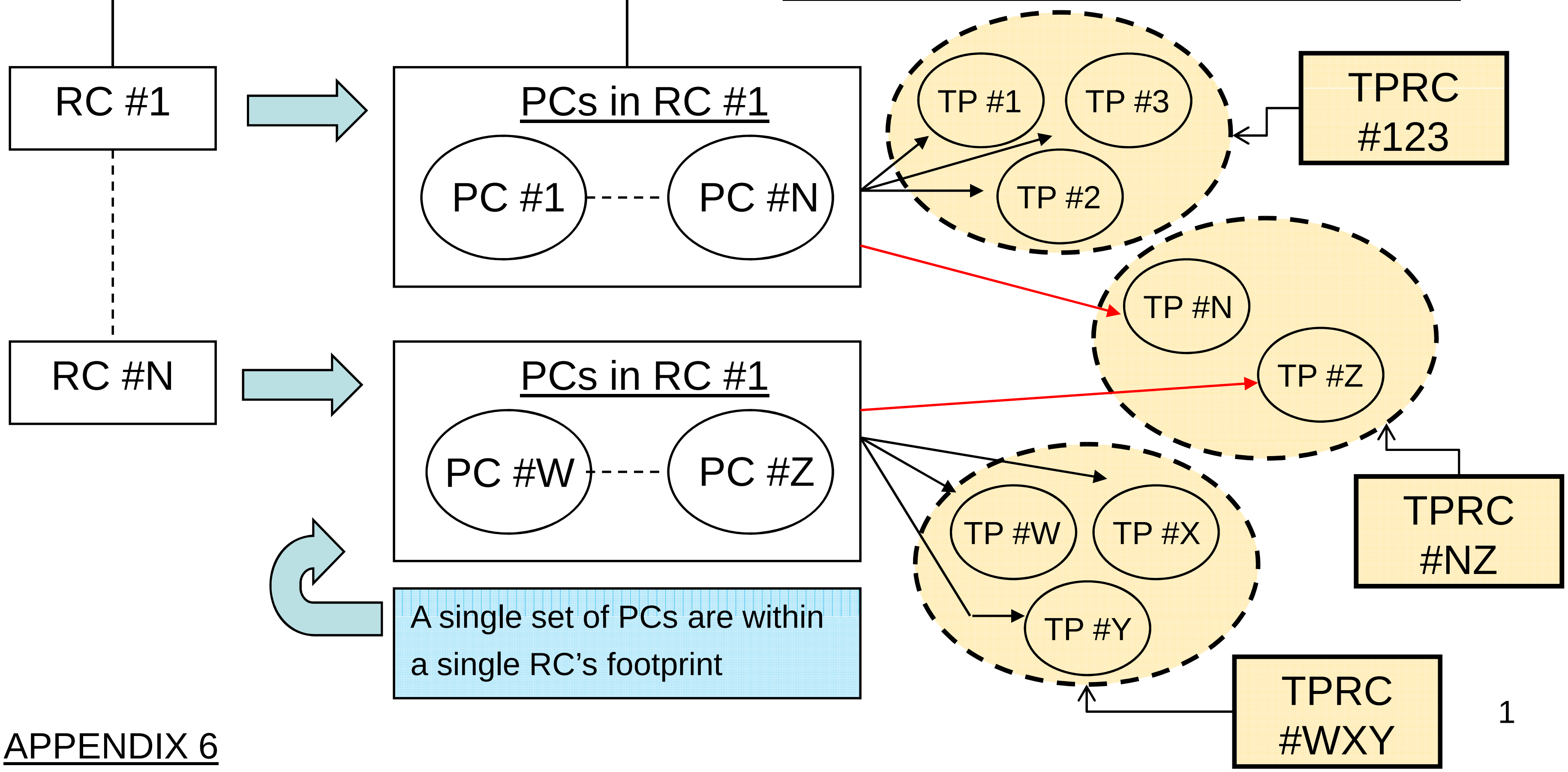
Interconnection

An **Interconnection** has one or more **Reliability Coordinators (RCs)** and associated **Planning Coordinators(PCs)**

TPs which decide to jointly perform reactive planning is called a TP Reactive Cluster (TPRC). A TPRC may contain ONE or more TPs (see TPRC #123 below). A TPRC may span multiple PCs or RCs- see TPRC #NZ.



APPENDIX 6

Formation of TPRCs

- One or more TPs may form a TPRC of functional entities for coordination of reactive planning.
- Electrically cohesive functional entities which can share VARs without causing significant BES voltage gradients may join the TPRC.
  - The TPRC documentation establishes the Criteria.

    (see Appendix 7 for one of many possible examples).
- The vast majority of VAR load & losses is expected to be met within the functional entities.
  - The TPRC would document the forecasted power factor obtained from all functional entities within the cluster.

APPENDIX 6

Reactive Planning Documents

- Two coordinated documents will be required from the TPRC for their PCs within the RC footprint
  - Reactive planning criteria (methodology or protocol)
  - Reactive planning implementation plan (5 year & 1 yr)
- Each document will have different sections that contain the criteria and implementation plan for each TPRC and associated PCs within the RC.
  - A TPRC may span multiple RCs.
  - If a TPRC spans RCs, identical TPRC sections will be included in the documents for each PC & RC footprint

Criteria Documentation

- The TPRCs and associated PCs within each RC footprint must provide a complete set of documents to the RCs for review and comment.
  - Different TPRCs may have different criteria based upon system differences
  - If a TPRC includes PCs from more than one RC, then identical TPRC criteria will be given to the affected RCs for review and comment.
  - The RCs and TPRC/PCs review this criteria and design basis primarily to identify operational implementation issues, control system design modifications, etc.

APPENDIX 6

Criteria Documentation Comments

- After review by the RC, the RC may provide written comments to the PCs & TPRCs.
- The PCs & TPRCs will either adjust the TPRC criteria documentation or they will explain to the RC why they have chosen not to change the criteria.

Implementation Plan Documentation

- Based upon the Criteria documentation, the TPRCs will submit a 5-year & 1-year implementation plan to the PCs for comment.
  - The documentation will show the plans for all TPRCs (and associated PCs) within the RC footprint
  - When the PCs have no comment, the PCs will forward the 5-year coordinated plan to the RCs for review, comment, and implementation of the one year plan.
  - If a TPRC includes PCs from more than one RC, then the TPRC's implementation plan would be submitted to all PCs and RCs for review

Implementation Plan Comments

- RCs may provide written comments, for which the PCs and TPRCs will either adjust their implementation plan documentation in response to an RC's written comments or explain why they have chosen not to change the implementation plan.

Appendix 7

Example Reactive Cluster and Dynamic Reserve Tests

Example Reactive Cluster and Dynamic Reserve Tests

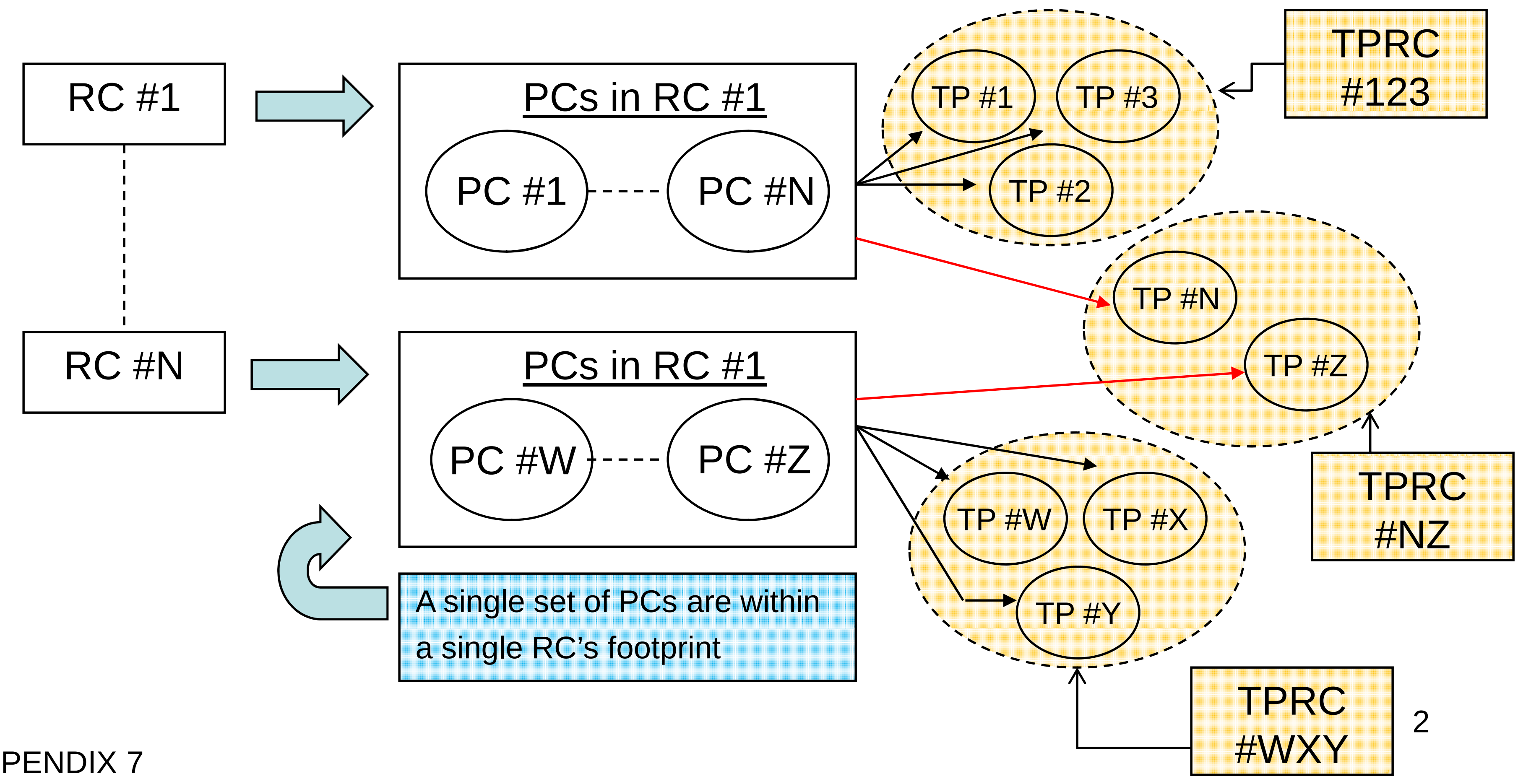
One of many ‘How to’ Examples

Rev. 05/18/09

APPENDIX 7

Example Transmission Planning Reactive Clusters (TPRCs)

TPs which decide to jointly perform reactive planning is called a TP Reactive Cluster (TPRC). A TPRC may contain ONE or more TPs (see TPRC #123 below). A TPRC may span multiple PCs or RCs- see TPRC #NZ.



APPENDIX 7

Example Coherency Test

- All TO zones prepare proposed 5th year peak load base cases, & PCs confirm documentation of compliance with TPL Standards, Table 1.
- TO zones #1, 2, & 3 propose a TPRC #123.
- TPRC #123 collectively has an internal worst base case lagging Power Factor of 9X% or higher.
- Conservation of reactive power requires the lagging reactive imports (if any) to be supported over TPRC #123 tie lines from other TPRCs. This is called TPRC #123 “Shared Reactive Reserve” (SRR).

TPRC Coherency Test Documentation

- Three part Coherency Test
  1. TPRC #123 reactive *internal* sharing among TO zones
  2. TPRC #123 reactive *external* sharing among TPRCs
  3. Collective TPRC *conservation of reactive energy* of TPRCs associated with its PCs and RC.
- Test 1 – TPRC *internal* coherency
  a) Document proposed base cases and TPRC #123 worst case power factor base case (highest reactive import, if any). Designated Base Case #1.
  b) Within TPRC #123 for each reactive exporting TO zone (if any), proportionately reduce reactive source capability or increase shunt MVAR bus load until exporting TO zone MVAR exports are zero, and

TPRC Coherency Test Documentation

c) For each reactive importing TO zone (if any), proportionately change shunt MVAR bus load until TPRC #123 total imports match the SRR net tie flow in Base Case #1.

d) If a Bulk Electric System (BES) bus within the TO zone changes voltage by more than Y% (such as 3%), then that TO zone is not ‘TPRC Internally Coherent’.

e) TO zones which fail the coherency test must provide reactive support/control to pass the test, or TO zones which do not pass the test may not remain a member of TPRC #123.

f) TO zones which can not pass the test in any TPRC must provide 100% of the TO zone’s total reactive load including all losses (TO, PSE, GO, DP & LSE).

TPRC Coherency Test Documentation

- Test 2 - *External* sharing among TPRCs
    A. Start with Test 1 final case which has passed *internal* coherency Test 1.
    B. For each remaining TO zone with reactive imports (if any), proportionately change shunt MVAR bus load until all TO zone imports are zero MVARs
    C. Confirm the remaining TO zones have zero reactive exports. If not, proportionately reduce reactive source capability or increase shunt MVAR bus load until exporting TO zone MVAR exports are zero.
    D. Continue the above process B and C until TPRC #123 reactive imports are zero. (SRR at zero imports.)

TPRC Coherency Test Documentation

- Test 2 (continued)

E. Each BES bus which changes from Base Case #1 voltage to Test 2 voltage by more than W% (such as 4%) is not coherent to share from external TPRCs.

F. TO zones which fail coherency Test 2 must provide reactive support/control to pass the test at every TPRC #123 BES bus, OR

G. TO zones which do not pass Test 2 at its BES buses may not remain a member of TPRC #123.

H. TO zones within each Planning Coordinator which are unable to pass Test 1&2 as a member of any TPRC, must provide sufficient reactive support/control capability to achieve unity power factor.

TPRC Coherency Test Documentation

- Test 3 – Conservation of Reactive Energy
  i. Start with Test 2 final base case for each TPRC which has passed coherency Test 1 & 2.
  ii. For the TPRCs within each RC control boundary, compute the non-diversified case total reactive load (including losses). Also compute the total reactive source capability within each RC.
  iii. Confirm each RC has sufficient reactive source capability under RC & TOP control to meet its total non-diversified reactive load (including losses).
  iv. If not, the associated TPRCs fail Test 3.
  v. Within an RC the collective PCs must coordinate a plan to pass Test 3 Conservation of Reactive Energy

Dynamic versus Static Resource Test

Test A – Dynamic versus Static Resource

1) Start with single worst base case for each RC which passed all TPL & coherency Tests 1, 2 & 3.
2) For PCs within each RC control boundary re-dispatch case to match RC *diversified* forecasted peak load. This *diversified* peak load case will have lower total reactive load than the total gross load in Test 3.
3) Confirm each RC has sufficient dynamic MVAR reserve *capability* (under RC & TOP control) to meet or exceed X% (such as 5%) of RC *total reactive MVAR demand* (RC diversified customer demand plus losses).

Dynamic versus Static Resource Test

4) If the dynamic MVAR reserve *capability* (under RC & TOP control) does NOT meet or exceed X% of RC *total reactive MVAR demand including losses*, the RC associated PCs & TPRCs fail Test A

5) The PCs shall coordinate plans to provide X% or more dynamic *reserve capability performance* by;
   - Lowering initial dynamic resource output
     - by adding additional static resources, lowering demand by DSM contracts, increasing SRR from other RCs (while passing Tests 1, 2, & 3)

   OR by

   - Adding new dynamic resource capability

6) All other Standards must also be met.

Appendix 8a.

Example WECC Voltage Stability Methodology

Summary of WECC Voltage Stability Assessment Methodology

This document is intended to provide clear summary guidelines to WECC members as to how these types of analysis should be conducted. It also provides additional guidance by suggesting a path for the user at instances where the WSCC Report on Voltage Stability Criteria, Undervoltage Load Shedding Strategy, and Reactive Power Reserve Monitoring Methodology, dated May 1998 (hereafter referred to as the RRWG Report) offers choices. For more information members should refer to the RRWG report.

Among the methods for assessing voltage stability, the most frequently used are P-V and V-Q analysis. Two flowcharts are provided in this summary; one describing P-V analysis and one describing V-Q analysis. Many of the assumptions used to complete the power flow simulations in these types of analysis are common to the two methods and are provided in Attachment A and referenced in the flowcharts. Even though the description here only covers load increase (Item a) and transfer path flow increases (Item m) out of the eighteen items listed in Section 2.3 of the RRWG Report and repeated below, the responsible entities should also investigate the remaining uncertainties to ensure that all reasonably severe operating conditions are covered.

The uncertainties for establishment of the voltage stability criteria in Section 2.3 are:

(a) Customer real and reactive power demand greater than forecasted
(b) Approximations in studies (Planning and Operations)
(c) Outages not routinely studied on the member system
(d) Outages not routinely studied on neighboring systems
(e) Unit trips following major disturbances
(f) Lower voltage line trips following major disturbances
(g) Variations on neighboring system dispatch
(h) Large and variable reactive exchanges with neighboring systems
(i) More restrictive reactive power constraints on neighboring system generators than planned
(j) Variations in load characteristics, especially in load power factors
(k) Risk of the next major event during a 30-minute adjustment period
(l) Not being able to readjust adequately to get back to a secure state
(m) Increases in major path flows following major contingencies due to various factors such as on-system undervoltage load shedding
(n) On-system reactive resources not responding
(o) Excitation limiters responding prematurely
(p) Possible RAS failure
(q) Prior outages of system facilities
(r) More restrictive reactive power constraints on internal generators than planned.

P-V Methodology
Part 1: Developing the P-V Curves

A. Develop a series of system normal condition base cases with increasing loads or transfer paths to run contingencies from **(Assumption Set A)**

A1. For load Serving Systems: Develop a series of load increase base cases starting from the expected load level corresponding to the planning standards and extending to the point at which voltage collapse is expected to be reached following contingencies. **(Assumption Set B)**

Note: The interface path(s) should measure <u>all</u> imports into the receiving region.

A2. For Transfer Paths: Develop a series of interface flow increase base cases starting at rated transfer and extending to the point at which voltage collapse is expected to be reached following contingencies. **(Assumption Set B)**

Note: All Transfer Path(s) into the receiving region should be monitored.

B. For each of the base cases from the series created above, select several contingencies judged to be the most severe. Run the Post-Transient power flow for each of the severe contingencies. **(Assumption Set C)**

C. Identify the critical bus(es) –
Select a group of 3-5 buses in the load area or that are expected to be severely impacted by the transfer path flow for each of the selected contingencies studied in B above to monitor voltage. These may be the buses with the lowest voltage or the highest voltage deviation. The buses electrically close to the outage may not be the ones that would be closest to the collapse point (e.g., Table Mt is closest to the collapse point for DC Bi-pole outage, but not electrically close to either DC termini).

D. Produce the P-V Curves –
For each selected contingency in B, develop the P-V curves by plotting the post-contingency voltages (at the buses selected in C) against the system load for the load area studies, and the post-contingency voltages (at the buses selected in C) against the pre-contingency flows for the transfer paths studies, until the voltage collapse point is reached.

P-V Methodology: Part 2: Determine the Maximum Load or Transfer allowable using the P-V Curves

(After the P-V curves are run)

A. Assess performance under various operating conditions
The maximum load or transfer limit operating point should be the lower of the following:
   1. 5% below the load (for load areas) or path flow (for transfer paths) at the collapse point on the P-V curve for Category A.
   2. 5% below the pre-contingency flow or load corresponding to the collapse point on the P-V curve for Category B contingencies.
   3. 2.5% below the pre-contingency flow or load corresponding to the collapse point on the P-V curve for Category C contingencies.

Note: The categories named above refer to the disturbance categories described in Table I of the NERC Planning Standards.

V-Q Methodology:
Part 1: Setting "Reactive Power Margin Requirements"

A. Create the 100% load or 100% transfer path base case **(Assumption Set A)**

A1. For load area studies, create the 105% or 102.5% load area base case **(Assumption Set B)**

Note: The interface path(s) should measure <u>all</u> imports into the receiving region.

A2. For transfer path studies, create the 105% or 102.5% transfer flow base case **(Assumption Set B)**

Note: All Transfer Path(s) into the receiving region should be monitored.

B. By running the post-transient power flow, develop post-contingency cases for each of the most severe contingencies for the cases with 100% load or transfer path flow and for the cases with 105% load or transfer path flow**. <u>(Assumption Set C)</u>**

C. Identify the critical bus(es)

- Identify the sub-set of the most critical buses (3-5) for each of the selected contingencies studied in B above. These may be buses with the lowest voltage or the highest voltage deviation. The buses electrically close to the outage may not be the ones that would be closest to the collapse point (e.g., Table Mt is closest to the collapse point for DC Bi-pole outage, but not electrically close to either DC Terminal).

D. Produce the V-Q Curves for each contingency:

- Apply a fictitious synchronous condenser at each critical bus identified earlier; one at a time.
- Solve the power flow case (either a standard or post-transient power flow solution can be used).
- Record the bus voltage (V) and the reactive output of the condenser (Q).
- Reduce the condenser scheduled output voltage in small steps (e.g., < 0.01 p.u.).
- Continue varying the condenser's output (or scheduled voltage) until sufficient points to identify the voltage collapse point have been collected.

E. Establish the Reactive Power Margin Requirements.

- Reactive Power Margin is defined as the value of the condenser output at the voltage collapse point on the V-Q curve where dQ/dV=0.
- The change in the reactive power margin between the two different load levels (100% and 105%) for the same Category B contingency and at the same bus is the Reactive Power Margin Requirement at that bus for that Category B contingency.
- The change in the reactive power margin between the two different load levels (100% and 102.5%) for the same Category C contingency and at the same bus is the Reactive Power Margin Requirement at that bus for that Category C contingency.
- Identify the Reactive Power Margin Requirement for other study years as desired by repeating the above steps for other years as necessary

Note: The categories named above refer to the disturbance categories described in Table I of the NERC Planning Standards.

V-Q Methodology:
Part 2: Assessing Performance against the "Reactive Power Margin Requirements"

(After the Reactive Power Margin Requirements have been established for the years of interest, the system can be tested to see if it meets these Requirements)

A. Create the 100% load or 100% transfer path base case **(Assumption Set A)**

B. By running the post-transient power flow, develop post-contingency cases for each of the most severe contingencies **(Assumption Set C)**

C. Plot V-Q curves and assess performance against the margin requirements
- Create V-Q curves for the selected contingencies (Categories B and C) in the study area for the study year to be investigated at the 100% load level or 100% transfer path flow level.
- Check to see if the VAR margin meets the Reactive Power Margin Requirements established previously for the same study year, bus and contingency.
- If the required VAR margin is not met, additional facilities, implementation of appropriate remedial action schemes, or reduction in load or interface flow would be required.

Attachment A : Power Flow Assumptions for P-V and V-Q Analysis

Assumption Set A: Modeling the 100% load or 100% Transfer Base Cases

- For load area studies, the load in the area of interest should be modeled based on the load forecast normally used for planning that area. (For the purpose of developing an extended P-V curve, base case may be developed at less than 100% load level.
- For transfer interface studies, the interface transfer should be modeled at its maximum rating and under the most critical system conditions for which the interface is rated (a range of conditions may be necessary for nomograms ratings).
- Assume constant MVA load models unless more accurate load models are available.
- Move the area slack and system swing bus outside the study area.
- Use standard power flow to solve the base case. Post-transient power flow should not be used to develop these cases.

Assumption Set B: Modeling the Load or Transfer Increase Case(s)

- Generation to supply the increasing load for load serving systems should come from generation that would normally have been dispatched to meet the load increase. Generation to supply increasing transfers should come from generation that would place the highest stress on the facilities of interest. The generators' outputs should not exceed the generators' maximum capability.
- The system swing bus can be used to account for system losses but its output should not exceed the generator's capability, otherwise the generation should be re-dispatched.
- When increasing load, also increase loads in closely neighboring systems if they have similar climatic or geographic characteristics.
- Although the load power factor is typically held constant when the load is increased, the power factor may be adjusted based on engineering discretion.
- As load is being increased, adjust automatic and manual devices (including generators) as needed that would operate within 30 minutes. Ignore overloads that cannot be corrected using such automatic and manual switching action. The 30 minute limit assumes that the load increase can be anticipated within a few hours to allow operator action. However, it is intended to avoid the addition of thermal units to the load increase cases without being specifically identified. If these units are needed, they should be included in the 100% base case.
- As transfer is being increased, adjust automatic devices as needed that would operate within 3 minutes. Ignore overloads that cannot be corrected using such automatic switching action. The 3-minute limit assumes that transfer path flow increases cannot be anticipated with enough time to allow corrective action(s) by the operator. It is intended to avoid the addition of *manual* devices to support the increase in transfer path flow without being specifically identified. If these devices are needed, they should be included in the 100% base case.

Assumption Set C: Modeling of Contingency Cases

- When the contingency involves load shedding, generator tripping, or a large change in system losses, a post-transient power flow should be used to re-establish the generation-load balance based on approximated governor action. Otherwise a standard power flow can be used.
- In accordance with WSCC's post-transient power flow methodology, allow switching of only those automatic devices that can complete switching in 3 minutes (e.g., automatic LTCs, automatic phase shifting transformers, SVCs, and other automatic switching devices)
- If the post-transient solution indicates that automatic actions would occur (such as automatic RAS, load shedding and generator tripping schemes), then rerun the case applying those actions.
- If discrete devices are required to solve contingencies for the 105% or 102.5% load (or transfer) case, these devices should be modeled in the 100% load (or transfer) case as well.

Appendix 8b

Example WECC Planning Standards

Western Electricity Coordinating Council

RELIABILITY CRITERIA

PART I - NERC/WECC PLANNING STANDARDS

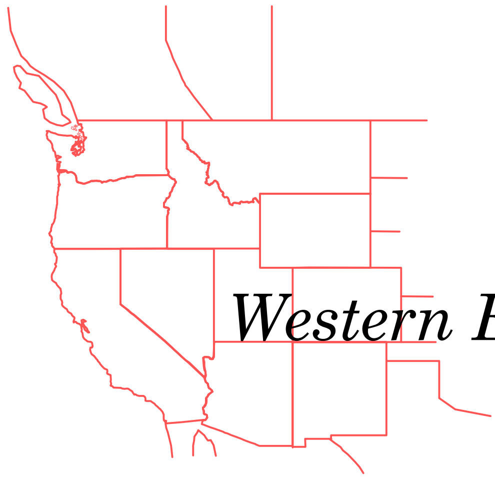
PART II - POWER SUPPLY ASSESSMENT POLICY

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.*

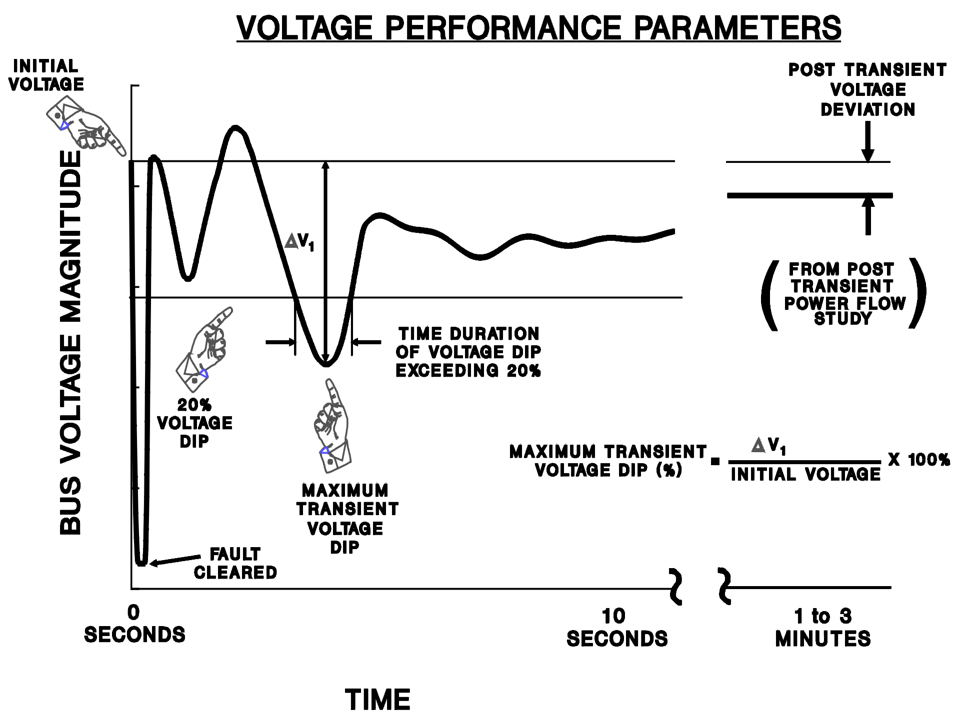


Figure W-1

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

Footnotes to Table I.

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

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

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

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

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

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

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

Introduction

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

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

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

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

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

Standards

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

Measurements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Introduction

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

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

Standards

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

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

Measurements

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

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

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

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

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

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

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

Facility connection requirements shall be maintained and updated as required.

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

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

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

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

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

Guides

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

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

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

Introduction

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

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

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

Standard

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

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

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

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

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

Measurements

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

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

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

Guides

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Introduction — Total and Available Transfer Capabilities

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

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

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

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

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

  ATC is expressed as:

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

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

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

Standards

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

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

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

Measurements

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

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

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

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

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

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

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

M2. Eliminated. Requirements included in Measurement M3.

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

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

Each Region's procedure shall specify (S1):

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

Guides

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

Introduction — Transfer Capability Margins

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

The definitions for CBM and TRM are:

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

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

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

Standards

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

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

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

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

Measurements

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

Each Region's CBM methodology shall (S1):

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

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

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

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

M2. Eliminated. Requirements included in Measurement M3.

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

This Regional procedure shall:

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

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

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

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

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

These procedures shall:

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

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

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

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

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

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

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

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

Each Region's TRM methodology shall (S2):

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

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

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

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

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

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

M7. Eliminated. Requirements included in Measurement M8.

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

This Regional procedure shall:

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

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

Introduction

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

Standards

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

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

Measurements

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

The comprehensive Regional requirements shall include the following items:

Technical requirements:

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

Criteria for the location of monitoring equipment:

5. Regional coverage requirements (e.g., by voltage, geographic area, electric area/subarea)
6. Installation requirements (e.g., substations, transmission lines, generators)

Testing and maintenance requirements:

7. Responsibility for maintenance and/or testing

Documentation requirements:

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

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

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

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

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

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

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

Guides

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

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

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

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

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 inter-connected 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**.

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

POWER SUPPLY ASSESSMENT POLICY

PART II

Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

Revised April 18, 2002

WESTERN ELECTRICITY COORDINATING COUNCIL

POWER SUPPLY ASSESSMENT POLICY

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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.

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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

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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 solid-state underfrequency relays. Electro-mechanical relays shall not be used as part of any coordinated load shedding program. In each island area, all relay settings shall be coordinated and based on the characteristics of that island area. It is essential that the underfrequency load shedding relay settings are coordinated with underfrequency protection of generating units and any other manual or automatic actions which can be expected to occur under conditions of frequency decline.

3. **Technical studies.** The coordinated automatic load shedding program shall be based on studies of system dynamic performance, under conditions which would cause the greatest potential imbalance between load and generation, and shall use the latest state-of-the-art computer analytical techniques. The studies shall be able to predict voltage and power transients at a widespread number of locations, as well as the rate of frequency decline, and shall reflect the operation of underfrequency sensing devices.

4. **Load shedding steps.** Automatic high-speed load shedding shall comply with the *WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan* so as to minimize the risk of further separation, loss of generation, excessive load shedding accompanied by excessive overfrequency conditions, and system shutdown.

5. **Generators isolated to local load.** Where practical, generators shall be isolated with local load to minimize loss of generation and enable timely system restoration in situations where the load shedding program has failed to arrest frequency decline.

6. **Separation.** The opening of intra-area and inter-area transmission interconnections by underfrequency relaying shall only be initiated after the coordinated load shedding program has failed to arrest frequency decline and intolerable system conditions exist.

7. **Voltage reduction.** If voltage reduction is utilized for manual load relief, such reduction shall not be made to the high voltage transmission system.

8. **Protection from high frequency.** In cases where area isolation with a large surplus of generation in relation to load requirements can be anticipated, automatic generator tripping or other remedial measures shall be used to prevent excessive high frequency and resultant uncontrolled generator tripping and/or equipment damage.

D. System Restoration

1. **Restoration plan.** Each transmission provider and control area shall have an up-to-date restoration plan and provide personnel training and telecommunication facilities needed to implement the restoration plan following a system emergency. Entities and coordinated groups of entities shall coordinate their restoration plans with other affected entities or coordinated groups of entities. All restoration plans shall be reviewed a minimum of every three years.

2. **Synchronizing.** To the extent possible, synchronizing locations shall be determined ahead of time and dispatchers shall be provided appropriate procedures for synchronizing. Such procedures should provide for alternative action to be taken if lack of information or loss of communication channels would affect resynchronization.

E. Control Center Backup

Each control area shall have a plan to provide continued operation in the event its control center becomes inoperable. For interconnected operations, the goal of this plan is to avoid placing a prolonged burden on neighboring control areas during a control center outage. Since most control centers differ in their internal functions and responsibilities, each control area should decide which specific functions, other than the basic functions shown below, will be necessary to continue their operations from an alternate location. These criteria do not obligate control areas to provide complete and redundant backup control facilities, but to provide essential backup capability. Each control area may, as an option, make appropriate arrangements with another control area to provide the minimum backup control functions in the event its primary control functions are interrupted. As part of its plan the control area is expected to comply with the following requirements (through automatic or manual means) as a minimum:

1. **Notification.** Provide prompt notification, which should include any necessary pertinent information, to other control areas in the event that primary control center functions are interrupted.

2. **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.

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WESTERN ELECTRICITY COORDINATING COUNCIL

DEFINITIONS

PART IV

Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

NERC/WECC PLANNING STANDARDS

AND

MINIMUM OPERATING RELIABILITY CRITERIA

D E F I N I T I O N S

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.

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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

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[1] Membership in WECC's Market Interface Committee, Planning Coordination Committee, and Operating Committee is in accordance with WECC's Bylaws.

[2] Formation of Subgroups is in accordance with the Market Interface Committee's, Planning Coordination Committee's, and Operating Committee's *Organizational Guidelines*.

instances a joint involvement will be needed to address requests that are applicable to planning, operating, and market issues. Changes to the WECC Standards may be offered by any individual or organization with a legitimate interest in electric system reliability, such as:

- Transmission owners
- Generation owners
- Independent System Operators (ISOs)
- Transmission dependent utilities
- Independent power producers
- Power marketers
- Customers, either retail or wholesale for resale
- State agencies concerned with electric system reliability
- WECC subgroups
- Electric industry organizations

A request to revise or develop a Standard must include an explanation of the need for a new or revised Standard and be accompanied by a preliminary technical assessment performed by, or prepared under the direction of, the entity(ies) supporting the request.

Step 2 – Assignment to Subgroup

The Board or Standards Committee then assigns the request to whichever Subgroup(s) is responsible for those issues. If a proposed new Standard or revision to an existing Standard has implications for any combination of planning, operations, or market issues, the Subgroup will include a composite of individuals having the appropriate planning, operations, and market expertise. Notification of such assignments will be posted on the WECC web site and sent to all parties that subscribe to the WECC Standards e-mail list. Interested parties may express their interest in participating in the deliberations of the Subgroup. The Subgroup membership will be administered in accordance with the WECC Bylaws.

Step 3 – Subgroup Begins Drafting Phase and Announces on WECC Web Site

The Subgroup will begin working on the new or revised request no later than at its next scheduled or special meeting. A minimum of 30 days notice will be provided prior to all Subgroup meetings in which new or revised Standards will be developed. Notification of such meetings will be posted on the WECC web site and sent to all parties that subscribe to the WECC Standards e-mail list. These meetings will be open to stakeholders having a legitimate interest in electric system reliability. The Subgroup Chair will allow some opportunity for outside comment and participation as the discussion progresses. However, the Subgroup Chair will not allow the discussion to interfere with productive discussions by the Subgroup members.

The Subgroup will review the preliminary technical assessment provided by the requester and may perform or request additional technical studies if considered necessary. The

Subgroup will complete an impact assessment report as part of its evaluation to assess the potential effects of the requested Standards change. The Subgroup may request from the Board or Standards Committee additional time to study the proposed new or revised Standard if the Subgroup believes it necessary to fully assess the proposed change. If the Subgroup determines that a new Standard or change in an existing Standard is needed, it announces the pending change, provides a summary of the changes it expects to draft, and provides an explanation as to why the new Standard or change in an existing Standard is needed. The announcement and the impact assessment report will be posted on the WECC web site and sent to all parties that subscribe to the WECC Standards e-mail list. If the Subgroup determines that a new or revised Standard is not needed, it prepares and posts the response to the party that submitted the proposal with a copy to the MIC, PCC, OC, or Board, as appropriate.

Step 4 – Draft Standard Posted for Comment

The Subgroup will post its first draft of the new or revised Standard on the WECC web site and provide 60 days for comments. The draft must include specific measurements for determining compliance and the estimated costs of compliance. Comments on the draft will be solicited from the WECC members and all individuals who subscribe to the WECC Standards e-mail list. Members of electric industry organizations may respond through their organizations, or directly, or both. All comments should be supplied electronically. WECC will then post all comments it receives on the WECC web site.

Step 5 – Subgroup Deliberates on Comments

Based on the comments it receives, plus its own review, the Subgroup will revise the draft Standard as needed. It will document its disposition on all comments received, and post its decisions on the WECC web site along with its second draft for either further industry review or Standards Committee vote. If the Subgroup believes the technical comments are significant, it will repeat Steps 3 and 4, before sending a revised draft to the Standards Committee. Steps 3 and 4 will be repeated as many times as considered necessary by the subgroup to ensure an adequate review from a “technical” perspective. The number of days for comment on each new draft of a proposed new or revised Standard will be 60 days, similar to the review period on the initial draft of the Standard. Parties who have their technical comments on a proposed Standard rejected by a Subgroup may write to the Standards Committee for further consideration of their comments.

A majority vote of the Subgroup is required to approve submitting the recommended Standard to the Standards Committee for a vote. The vote may be by mail, conference call and/or e-mail ballot.

Step 6 – Subgroup Submits Draft for Standards Committee Vote

The Subgroup’s final draft Standard is posted on the WECC web site and sent to the Standards Committee for a vote. The posting will include all comments that were not incorporated into the draft Standard and the date of the expected Standards Committee's vote. The posting will also be sent to the Standards e-mail list with attachments. Proposed Standards will be posted no less than 30[3] days prior to the Standards Committee vote.

Standards may be voted on in their entirety or by individual provisions. The Subgroup will determine how each Standard will be addressed for vote. The Subgroup will also recommend the subdivisions to be addressed and voted on as individual provisions. To be considered by the Standards Committee, any "no" votes, by Subgroup members, on a proposed Standard should be accompanied by a text explaining the "no" vote and if possible specific language that would make the Standard acceptable.

Step 7 – Standards Committee Votes on Recommendation to Board

The Standards Committee will vote on the draft Standard no later than at its next scheduled or special meeting. A minimum of 30[4] days notice will be provided prior to all Standards Committee meetings in which new or revised Standards will be considered for approval. Notification of such meetings will be posted on the WECC web site and sent to all parties that subscribe to the WECC Standards e-mail list. Whenever it determines that a matter requires an urgent decision, the Board may shorten the time period set forth in this section, provided that: 1) notice and opportunity for comment on recommendations will be reasonable under the circumstances; and 2) notices to Members will always contain clear notification of the procedures and deadlines for comment. If the Standards Committee approves the Standard, it sends its recommendation, the draft Standard, and any comments on which the Standards Committee did not agree, plus Standards Committee minority opinions, to the Board for final approval. To be considered by the Board, any "no" votes, by members of the Standards Committee, on a proposed Standard should be accompanied by a text explaining the "no" vote and if possible specific language that would make the Standard acceptable. Proposed Standards will be posted no less than 30[5] days prior to the Board vote. The date of the expected Board vote shall also be posted. The Standards Committee may amend or modify a proposed Standard. The reasons for the modification(s) shall be documented, posted, and provided to the Board. If the Standards Committee's recommendation changes significantly as a result of comments received, the committee will post the revised recommendation on the WECC web site, provide e-mail notification to Members, and provide no less than ten (10) days for additional comment before reaching its final recommendation. Any parties that object to the modifications may appeal to the appropriate Appeals Committee. These items shall all be posted on the WECC web site for general review. If the Standards Committee does

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[3] WECC Bylaws, Section 8.6 – require "not less than ten (10) days notice of all standing committee meetings…"

[4] WECC Bylaws, Section 8.6 – require "not less than ten (10) days notice of all standing committee meetings…" Section 8.7 – "All committee meetings of the WECC will be open to any WECC Member and for observation by any member of the public."

[5] WECC Bylaws, Section 7.5.1 – "Except as set forth in Section 7.5.2 regarding urgent business, all regular business of the Board will occur at the Board meetings, at least twenty-one (21) days' advance notice of which has been provided…"

not approve the Standard, it may return the draft to the Subgroup for further work or it may terminate the Standard development activity with the posting of an appropriate notice to the Standards originator, the Subgroup, and the Board (if appropriate).

A majority vote of the Standards Committee, as specified in Section 8.5.4 of the WECC Bylaws, is required to approve submitting the recommended Standard to the Board for a vote. The vote may be by mail, and/or e-mail ballot.

Step 8 – Appeals Process

After approval and posting by the Standards Committee, any due process or technical appeals are due, in writing, to the respective Due Process Appeals Committee or Technical Appeals Committee within 15 days. If an Appeals Committee accepts the appellant's complaint, it rejects the draft Standard and refers the complaint to the Standards Committee or Board for further consideration. If an Appeals Committee denies the complaint, it approves the Standard for referral to the Board. Deliberations of the Appeals Committees shall not exceed 15 days.

Step 9 – Board Approval

The Board will vote on the proposed Standard no later than at its next scheduled or special meeting. It will consider the Standards Committee's recommendations and minority opinions, all comments that were not incorporated into the draft Standard, and inputs from the Due Process and Technical Appeals Committees. To preserve the integrity of the due process Standards development procedure, the Board may not amend or modify a proposed Standard. If approved, the Standard is posted on the WECC web site and all parties notified. If the Standard is not approved, the Board may return the Standard to the Standards Committee for further work or it may terminate the Standard activity with an appropriate notice to the Standard originator and Standards Committee. These Board actions will also be posted.

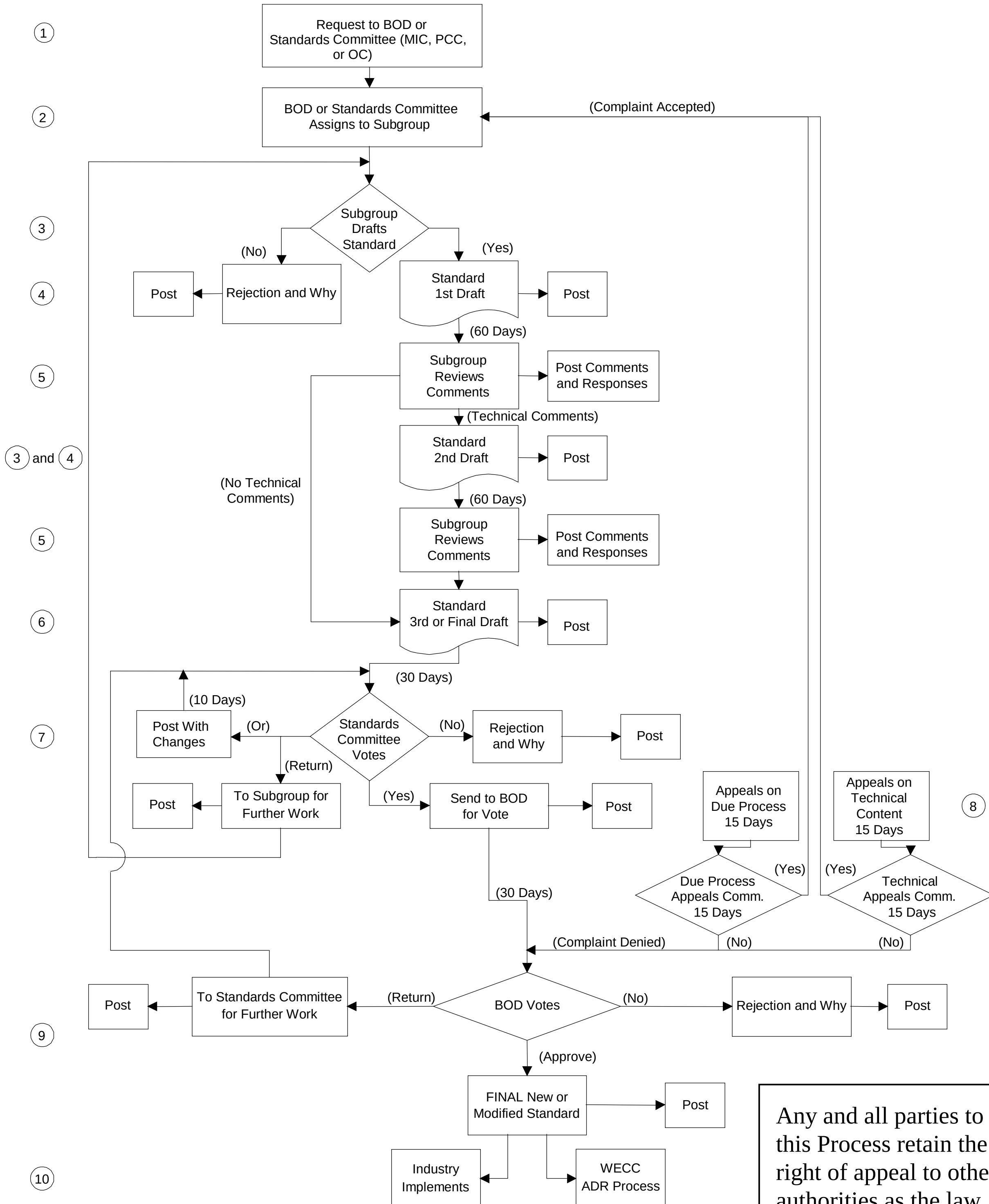
A majority vote of the Directors present at a Board meeting, as specified in Section 7.2 of the WECC Bylaws, is required to approve the recommended Standard.

Step 10 – Standard Implementation or Further Appeals

Once the Board approves a new or modified Standard, all industry participants are expected to implement and abide by the Standard in accordance with accepted WECC compliance procedures. Should a party continue to object to the new or modified Standard, that party may through a WECC member have access to WECC's alternative dispute resolution procedure to address its objections or seek other remedies as appropriate. Any and all parties to this Process retain the right of appeal to other authorities as the law allows.

Revised for Consistency with WECC Bylaws: June 21, 2002

Process for Developing and Approving WECC Standards



Any and all parties to this Process retain the right of appeal to other authorities as the law allows.

Appendix 9

Example PJM Voltage Control

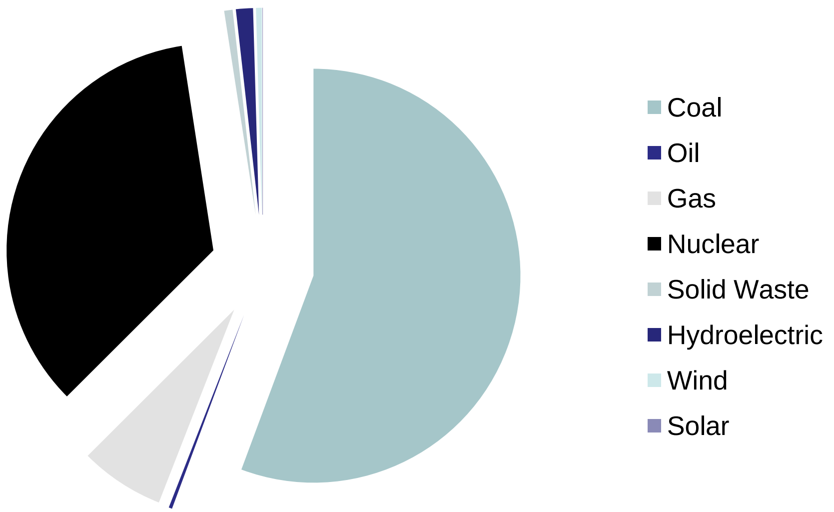
Voltage Control in PJM

Frank J. Koza
Executive Director, System Operations
PJM Interconnection

PJM Energy Market

PJM Generation by Fuel Source (GWh) in 2008		
	GWh	Percent
Coal	405649	55.7
Oil	1919	0.3
Gas	48020	6.6
Nuclear	255078	35
Solid Waste	4824	0.7
Hydroelectric	9710	1.3
Wind	3327	0.5
Solar	0	0
Total	728527	100

- 91% of PJM's energy comes from coal and nuclear generation, with nuclear providing 35% of the total
- PJM supplies about 15% of the total United States load



Voltage Operating Criteria (from PJM Manual M-3)

- No facility will violate normal voltage limits on a continuous basis and that no facility will violate emergency voltage limits following any simulated facility malfunction or failure.
- If a limit violation develops, the system is to be returned to within normal continuous voltage limits within 15 minutes but a 30-minute maximum time is allowed.
- In addition, the post-contingency voltage, resulting from the simulated occurrence of a single contingency outage, should not violate any of the following limits:

Post-contingency simulated voltage lower than the Emergency Low voltage limit, or higher than the High voltage limit.

Post-contingency simulated voltage drop greater than the applicable Voltage Drop limit (in percent of nominal voltage).

Post-contingency simulated angular difference greater than the setting of the synchro-check relay less an appropriate safety margin (ten degrees for a 500 kV bus). The angular difference relates to the ability to reclose transmission lines.

Base Line Voltage Limits and Actions

PJM BASE LINE VOLTAGE LIMITS

PJM Base Line Voltage Limits						
Limit	**500 kV**	**345 kV**	**230 kV**	**138 kV**	**115 kV**	**69 kV**
High	550 (1.10)	362 (1.05)	242 (1.05)	145 (1.05)	121 (1.05)	72.5 (1.05)
Normal Low	500 (1.00)	328 (.95)	219 (.95)			
Emergency Low*	485 (.97)	317 (.92)	212 (.92)			
Load Dump*	475 (.95)	310 (.90)	207 (.90)			
Voltage Drop Warning*	2.5%	4-6%	4-6%			
Voltage Drop Violation*	5-8%**	5-8%	5-8%			

* Refer to PJM Manual for Emergency Procedures (M

** The voltage drop violation percentage may vary dep

Exhibit 5: PJM Base Line Volt

The following chart details PJM's Voltage Operating Guidelines for a Post-Contingency Simulated Operation.

Voltage Limit Exceeded	If post contingency simulated voltage limits are violated	Time to correct (minutes)
High Voltage	Use all effective non-cost and off-cost actions.	30 minutes
Normal Low	Use all effective non-cost actions.	Not applicable
Emergency Low	Use all effective non-cost actions, off-cost actions, and emergency procedures except load shed.	15 minutes
Load Dump Low	All of the above plus, shed load if analysis indicates the potential for a voltage collapse.	5 minutes
Voltage Drop Warning	Use all effective non-cost actions.	Not applicable
Voltage Drop Violation	All effective non-cost and off-cost actions plus, shed load if analysis indicates the potential for a voltage collapse.	15 minutes

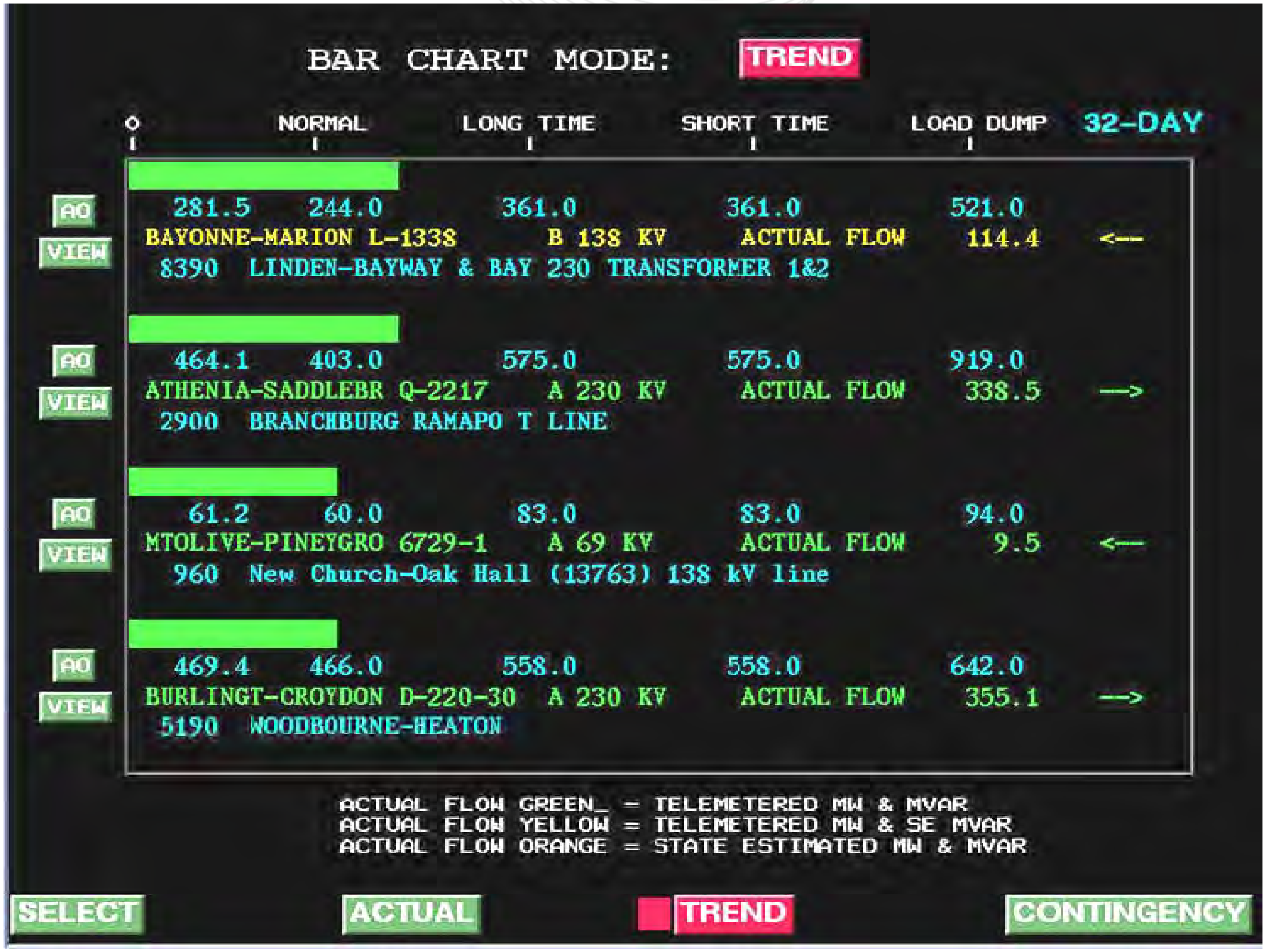
NERC Standards require PJM to operate within thermal, voltage, and stability limits; and implement corrective action on a timely basis, as shown here for voltage limits.

- Switching of capacitors or reactors
- Phase Angle Regulator tap adjustments (PARs)
- Adjust transformer tap settings
- Adjust generator excitation
- Reconfiguation
- Transaction curtailment
- Generation redispatch
- Emergency procedures

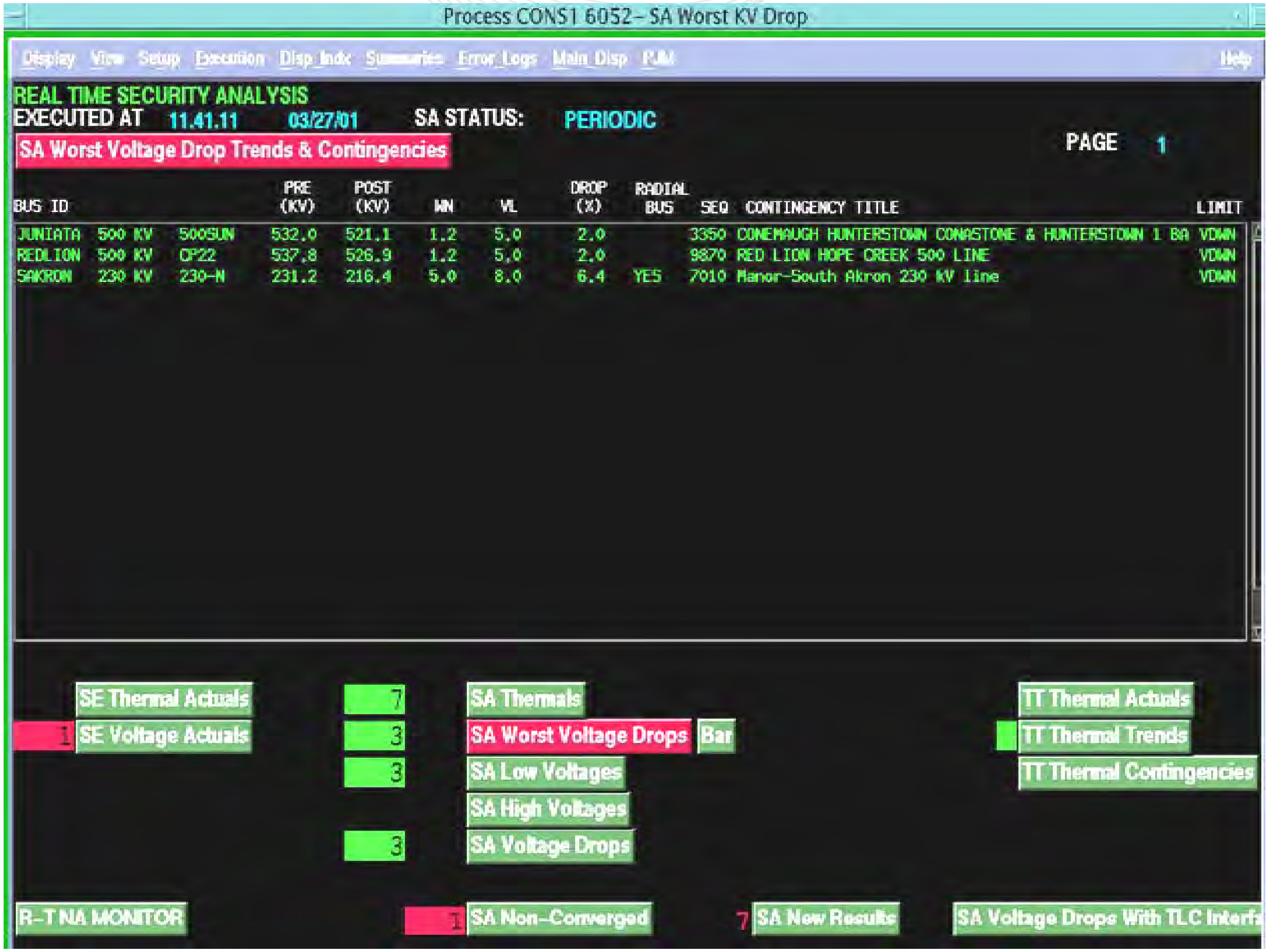
These actions can be used pre-contingency to control post-contingency operation so as not to exceed emergency ratings on a simulated basis.

- Some nuclear owners in PJM have more restrictive post-contingency voltage limits than the default limits for the unit trip
  - PJM Energy Management System (EMS) is calculating post-contingency voltages every minute, via a simulation (real time contingency analysis -- RTCA)
  - If the simulation shows an violation of the limit, then the nuclear plant is notified and options are discussed
  - Nuclear plant can opt for: (1) generation redispatch or (2) take corrective action inside the plant

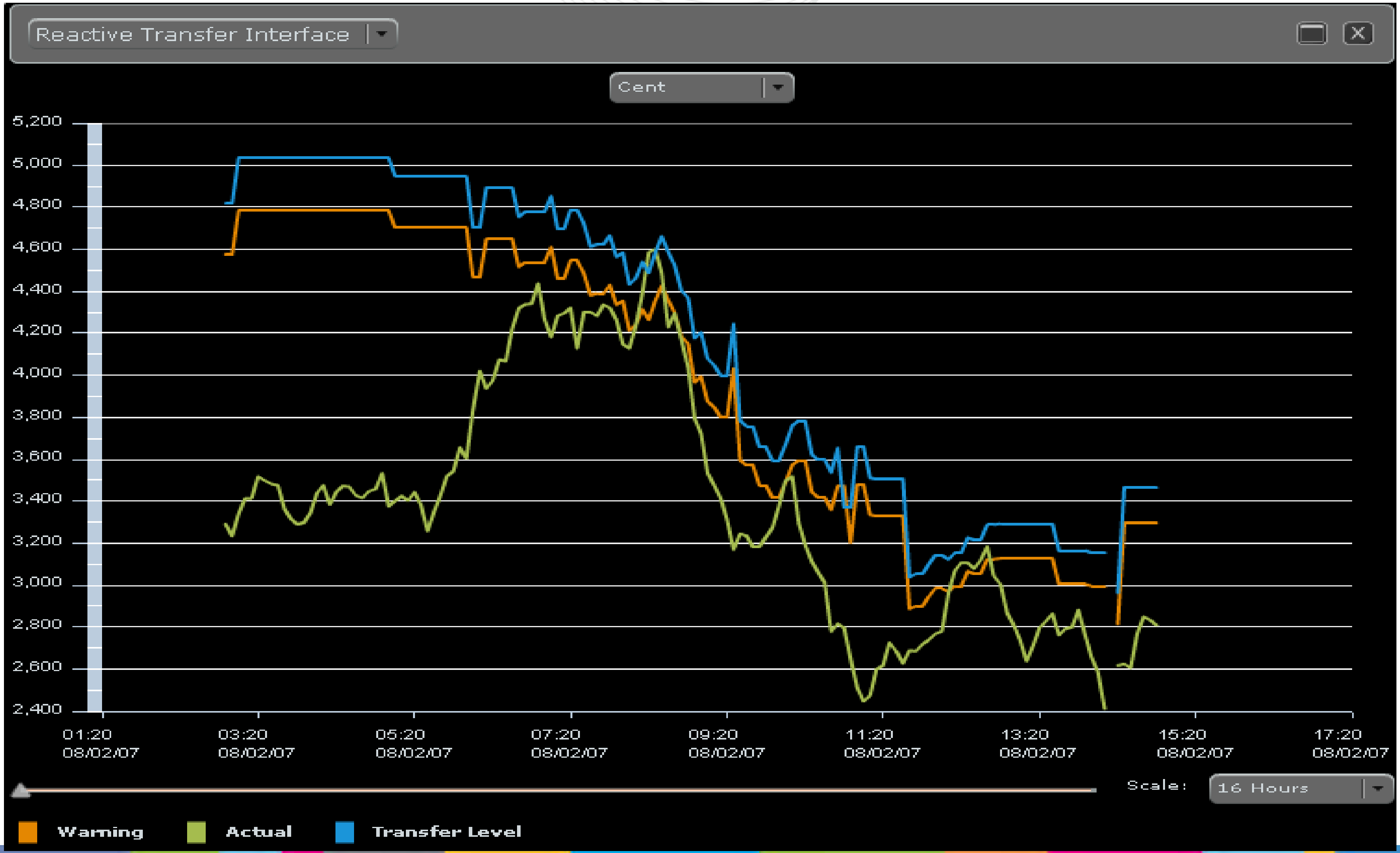
- Real Time Monitoring
  - Telemetry
  - State Estimator
  - Security Analysis
  - Security Constrained Economic Dispatch (for generation redispatch)
  - Transfer Limit Calculator (performs real time voltage collapse calculation to establish MW transfer limit with appropriate margins for the operators)


BAR CHART MODE: TREND
0
NORMAL
LONG TIME
SHORT TIME
LOAD DUMP
32-DAY
AO
VIEW
281.5 244.0 361.0 361.0 521.0
BAYONNE-MARION L-1338 B 138 KV ACTUAL FLOW 114.4 <---
8390 LINDEN-BAYWAY & BAY 230 TRANSFORMER 1&2
AO
VIEW
464.1 403.0 575.0 575.0 919.0
ATHENIA-SADDLEBR Q-2217 A 230 KV ACTUAL FLOW 338.5 --->
2900 BRANCHBURG RAMAPO T LINE
AO
VIEW
61.2 60.0 83.0 83.0 94.0
MTOLIVE-PINEYGRO 6729-1 A 69 KV ACTUAL FLOW 9.5 <---
960 New Church-Oak Hall (13763) 138 kV line
AO
VIEW
469.4 466.0 558.0 558.0 642.0
BURLINGT-CROYDON D-220-30 A 230 KV ACTUAL FLOW 355.1 --->
5190 WOODBOURNE-HEATON
ACTUAL FLOW GREEN_ = TELEMETERED MW & MVAR
ACTUAL FLOW YELLOW = TELEMETERED MW & SE MVAR
ACTUAL FLOW ORANGE = STATE ESTIMATED MW & MVAR
SELECT
ACTUAL
TREND
CONTINGENCY

Voltage Drop Monitoring



Transfer Limit Calculator Monitoring



Transmission (TOs) owners have full EMS suite of tools

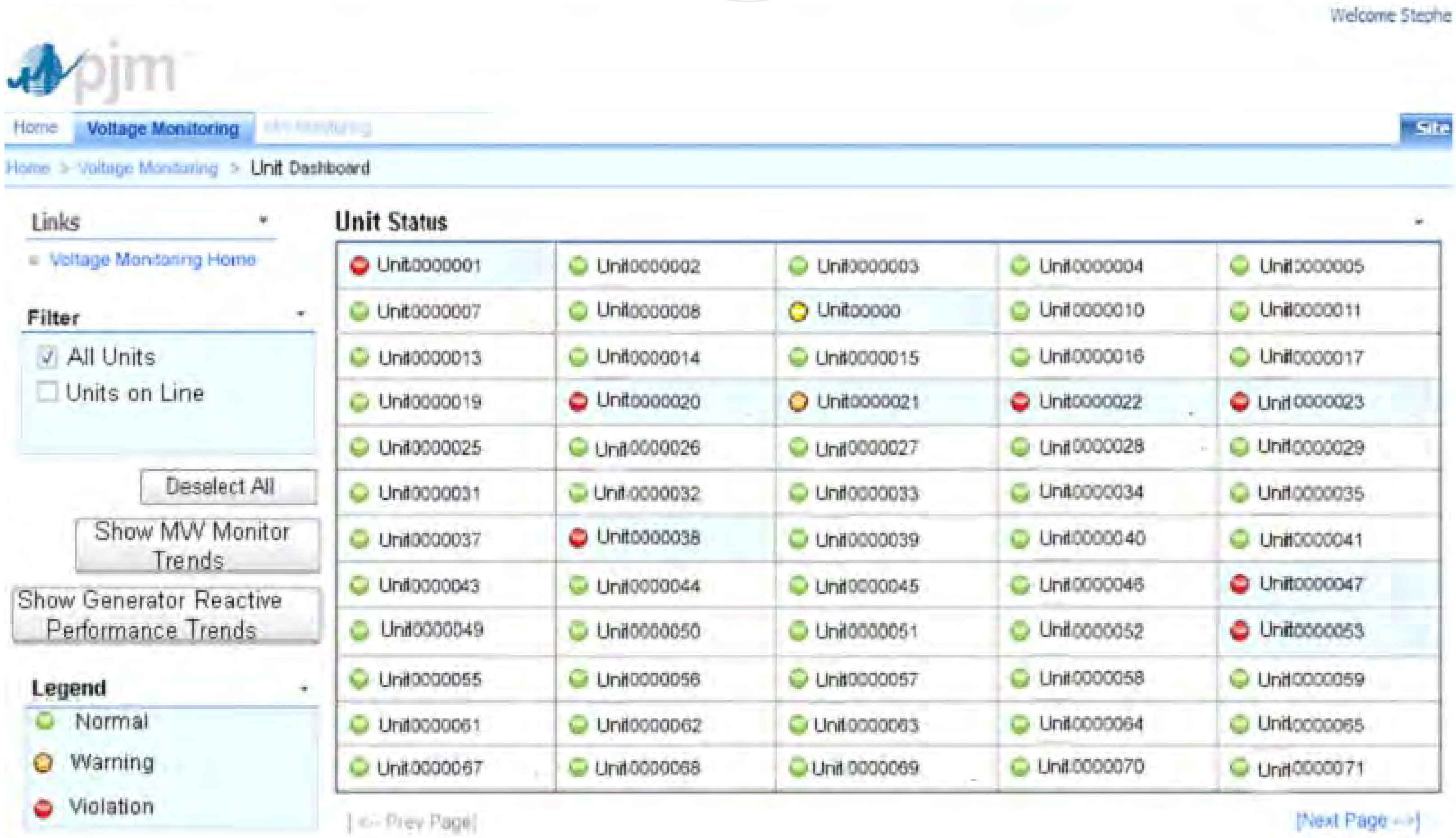
PJM EMS workstation to be installed in the TO control centers this year

Generation Performance Monitor (GPM)

- Provides real time voltage
- Voltage schedule limits
- Performance trends
- Alarms

Delivered to the transmission owner control room <u>and</u> the generation plants via a secure Web services application

GPM Summary Screen



GPM Individual Plant Screen

Appendix 10

ISO New England Op Procedure 17 Appendix B

Operating Procedures

ISO New England Operating Procedure No. 17

Load Power Factor Correction – Appendix B – Methodology for Developing Load Power Factor Limits

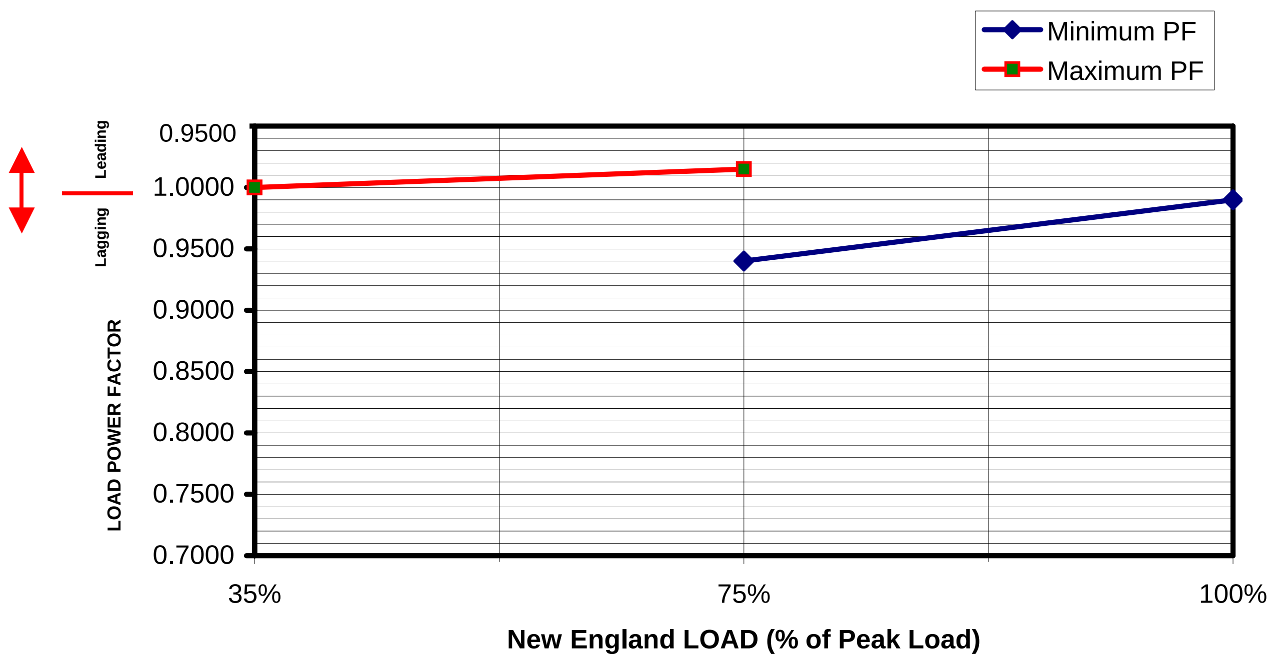
Effective Date: October 1, 2006
Revision No. 5

APPENDIX B - METHODOLOGY FOR DEVELOPING LOAD POWER FACTOR LIMITS

I. OVERVIEW

The methodology set forth in this Appendix shall be used to establish minimum and maximum load power factor limits for each area at three discrete load levels: heavy (100% of the CELT 90/10 load forecast for the study year), medium (75% of the CELT 50/50 load forecast for the study year), and light load (35% of the CELT 50/50 load forecast for the study year). These load levels may be modified by the VTF from time to time, as system changes dictate. A curve connects the two minimum points and another curve connects the two maximum points. The two curves represent the range of load power factors that establish the standard for the area. The following figure shows an example of minimum and maximum power factors for an area, as a function of load level.

Figure 1.1: Example of Load Power Factor Curve for a Given Area



II. TESTING CRITERIA

A general criterion is used to determine the minimum and maximum power factors at each load level, for all areas. The general criteria consist of two components; 0 VAR Interchange and minimum/maximum voltage.

1. **0 VAR Interchange –**When the area load power factor is at its maximum, under conditions biased to promote excess capacitance and high voltage, no contingency can result in VARs having to be exported out of a subject area. When the area load power factor is at its minimum, under conditions biased to promote large reactive losses and low voltage, no contingency can require that VARs be imported into the subject area. Note that the Zero VAR Interchange requirement only applies during post-contingency conditions. VARs can be exchanged between areas during pre-contingency (i.e. “all-lines-in”) conditions. Zero VAR Interchange makes each area responsible for its own reactive needs under stressed conditions and minimizes the need to consider voltage/reactive performance of areas outside of the area being studied.

2. **Minimum/Maximum Voltage –** When the area load power factor is at its maximum, a significant number of transmission busses (69 kV and above) within the subject area can’t exceed the high voltage design criteria of the Transmission Owners in the area. When the area load power factor is at its minimum, a significant number of transmission busses (69 kV and above) within the subject area can’t drop below the low voltage design criteria of the Transmission Owners in the area. A “significant number of transmission busses” is to be determined by the VTF, on a case-by-case basis.

Note that both criterion described above are to be applied at each load level. The most limiting of the two establishes the load power factor requirement for a given load level. For some load levels, the VAR interchange criterion may result in the most restrictive load power factor requirement. For other load levels, the min/max voltage criterion may result in the most restrictive load power factor requirement.

Limiting Criterion for Minimum Power Factor: Capped at Unity - The maximum allowable minimum load power factor is unity, for any load level. If the VAr Interchange or Minimum/Maximum Voltage criteria indicate that a leading minimum load power factor is needed, transmission solutions (e.g. transmission capacitors) should be investigated.

III. LOAD FLOW DEVELOPMENT

1. Load Levels to be Modeled

a) Summer Peak Load (100% of the CELT 90/10 load forecast for the study year)
b) Summer Intermediate Load (75% of the CELT 50/50 load forecast for the study year)
c) Spring Light Load (35% of the CELT 50/50 load forecast for the study year)

2. Load Data

a) MW loads at each bus are to be initialized using Company projections for the appropriate load level. MW load values contained in New England Library load flow cases are typically suitable.
b) MW loads at each bus are to be scaled to the appropriate load level (i.e. 100%, 75%, or 35%) using the extreme weather 90/10 load forecast for New England for the 100% case and the normal weather 50/50 load forecast for New England for the 75% and 35% cases, as published in the most current CELT report.
c) Loads are independent of voltage (constant PQ representation).

3. Generator Data and Dispatch

a) For each load level, generators are to be dispatched economically in the base cases, assuming all New England units are available and respecting reserve requirements.
b) Generator voltage schedules must not exceed limits specified in ISO New England Operating Procedure 12 (OP 12) – Voltage and Reactive Control, Appendix B (Voltage and Reactive Survey).
c) Generator Reactive limits are equal to the VAR limits at Claimed Capability per ISO New England OP 14 – Technical Requirements for Generation, Demand Resources and Asset Related Demands, Appendix B (Generator Reactive Data) as documented on the NX-12D Forms.
d) Stations Service loads of all large generators are to be modeled as documented on the NX-12D Forms These loads are not to be tripped with the contingent generator.

4. Capacitors/Reactors

All sub transmission/distribution capacitors and reactors (below 69 kV) are to be considered as part of the area load. Note that this requires all sub-transmission/distribution capacitors and reactors to be equivalenced with load in the load flow, unless the sub-transmission is interconnected in such a way that equivalencing is not beneficial. If a transmission capacitor or reactor is designated as “Local Area”, the transmission entity cannot use this capacitor or reactor to determine the load power factor requirements of the area. This avoids taking credit for the same capacitors or reactors twice, one at the study level and one at the survey level. The “Local Area” transmission capacitors or reactors listed in OP 17 Appendix C, Table 3 must be turned off during all testing.

5. Tie Lines

a) Tie lines between OP 17 areas must be split in half so that VAR Interchange between the areas is metered at the electrical midpoint of each tie line. Exceptions may be applicable in cases where contracts specify entitlements to line charging, or in cases where splitting the lines has no significant impact on VAR allocations between areas.
b) Inter-Area Interface transfers tested up to transfer limits where appropriate.
c) HVDC Tie Lines should be treated like generators, and dispatched accordingly.

6. Solution Parameters for Contingency Testing

a) Automatic load tap changing is allowed on all tests.
b) Phase Angle Regulators (PARs) allowed to regulate flow.
c) The system swing bus is located outside of New England with no regulation of area interchange flows.

7. Load Power Factor Measurement

The load power factor must be measured at the transmission level (i.e. at the high side of the transmission step down transformers), typically the 115 kV or 69 kV bus.

IV. CONTINGENCIES TO BE TESTED

All normal contingencies, as defined in OP 19, are to be tested. These contingencies consist of individual transmission facilities (i.e. transmission lines, transformers, generators), as well as contingencies that result in the loss of multiple transmission facilities (i.e. Breaker Failure and Double Circuit Tower Contingencies) that have unacceptable inter-Area impact.

All Special Protection Systems (SPSs) are to be appropriately modeled in the loadflow simulations.

V. TESTING PROCEDURE

The testing criteria (Zero VAR Interchange and Minimum/Maximum voltage) are to be applied to each area, at each load level, with the most restrictive load power factor becoming the area standard.

Load flows for these tests are developed from the guidelines described in Section III of this document ("Load Flow Development"). Testing focuses only on one area at a time – i.e. "study area". To develop a minimum load power factor limit for a given load level, the loadflow case is biased toward low voltage conditions. To develop a maximum load power factor limit for a given load level, the loadflow case is biased toward high voltage conditions.

A.) MINIMUM LOAD POWER FACTOR - The minimum load power factor for each load level is determined as follows.

1. **Low Voltage Bias -** Starting from an economic dispatch, generation should be biased toward low voltage conditions:

   a) **Import Areas –** In areas where less economical generation exists in comparison with the load (i.e. "Import Areas"), the base cases should be biased for low voltage as follows:

      a. Shut off generator with largest net VAr producing capability (unless such generator is required to run for reliability reasons), within subject area.

      b. With largest generator in subject area shut off, adjust New England Transmission Interface transfers so as to depress transmission voltages within subject area. Interface transfers that tend to depress area voltages are to be dispatched up to or near existing limits, depending on the practicality of dispatch and operations at each load level. This could involve dispatching up to existing Import limits for Import Interfaces (e.g. Boston Import), and/or dispatching up to existing limits for through-flow Interfaces (e.g. North-South).

   b) **Export Areas –** In areas where more economical generation exists in comparison with the load (i.e. "Export Areas"), the base cases should be biased for low voltage as follows:

      a. Adjust New England Transmission Interface transfers so as to depress transmission voltages within subject area. This usually involves dispatching to existing export limits for the subject area.
      Interface transfers that tend to depress area voltages are to be dispatched up to or near existing limits, depending on the practicality of dispatch and operations at each load level.

2. **Reactive Dispatch -** For each load level, VAR support from all area generation and transmission VAR sources is to be maximized:

   a) Turn on all Transmission VAR sources (e.g. Capacitor banks, Statcoms, etc.) in area (subject to min and max voltage schedule at all busses, as well as other constraints, e.g. Phase II filter requirements, dynamic reserve requirement for statcoms, etc.).

   b) Shut off all Transmission VAR absorption facilities (e.g. Reactors, etc.) in subject area (subject to min and max voltage schedule at all busses, as well as other constraints, e.g. Phase II filter requirements, dynamic reserve requirement for statcoms, etc.).

   c) Set voltage schedules of all area generators to maximum.

The general approach, when determining the minimum load power factor, is to utilize as much generation and transmission VAR support in the area as possible. Note that Distribution VAR support is to be considered part of the area load.

3. **Zero VAR Interchange Testing–** For each load level, the minimum load power factor based on Zero VAR Interchange is to be determined as follows:

   a) Determine the contingency (transmission line or generator) that results in the highest VAR losses within the subject area.

   b) Generation resources may be adjusted to simulate 10 minutes worth of post-contingent operator actions to relieve transmission overloads exceeding the Long Term Emergency (LTE) limit. Compensate for a generator contingency by depleting the area's 10 minute reserve and starting up to two thirds of the area's ICU's. Pick up the remainder outside the area, but within New England. Adjust generation to the extent possible to relieve overloads.

   c) Adjust the area load power factor until VAR Import into the subject area is zero for the contingency determined above. Note: A uniform load power factor must be applied (i.e. the same load power factor must be applied to each bus in the area).

   d) The area load power factor at which the VAR import into the area is zero constitutes the minimum load power factor based on the Zero VAR Interchange criterion.

4. **Voltage Criteria Testing –** For each load level, the minimum load power factor based on voltage criteria is to be determined as follows:

   a) Determine the contingency that results in the lowest transmission voltages in the subject area

   b) Adjust the area load power factor until a significant number of transmission busses (69 kV and above) do not drop below the design criteria of Transmission Owners in the area. This power factor constitutes the minimum load power factor for the area based on voltage criteria. Note: A uniform load power factor must be applied (i.e. the same load power factor must be applied to each bus in the area).

5. **Limiting Power Factor –** For each load level, the most restrictive load power factor, based on either Zero VAR Interchange or Minimum Voltage, becomes the area standard.

B.) MAXIMUM LOAD POWER FACTOR - The maximum load power factor for each load level is determined as follows.

1. **High Voltage Bias -** Starting from an economic dispatch, generation should be biased toward high voltage conditions as follows (for either Export or Import Areas):

   a. Shut off generator with largest net VAR absorbing capability (unless such generator is required to run for reliability reasons), within the subject area.

   b. With the largest generator in subject area shut off, adjust the New England transmission interface transfers so as to inflate transmission voltages within subject area. This entails a dispatch that minimizes I^2X losses in the subject area.

2. **Reactive Dispatch -** For each load level, VAR absorption capability from all area generation and transmission VAR facilities is to be maximized:

   a. Shut off all transmission VAR sources (e.g. capacitors, etc.) in area (subject to min and max voltage schedule at all busses, as well as other constraints (e.g. Phase II filter requirements, dynamic reserve requirement for statcoms, etc.).

   b. Turn on all transmission VAR absorption facilities (e.g. reactors, Statcoms, etc.) in area (subject to min and max voltage schedules at all busses, as well as other constraints (e.g. Phase II filter requirements, dynamic reserve requirements for statcoms, etc.).

   c. Set the voltage schedules of all area generators to minimum.

   The general approach is to utilize as much generation and transmission VAR absorption capability in the area as possible when determining the maximum load power factor. Note that Distribution reactors are to be considered part of the area load.

3. **Zero VAR Interchange Testing–** For each load level, the maximum load power factor based on Zero VAR Interchange is to be determined as follows:

   a. Determine contingency that results in the highest loss of VAR absorption capability within the subject area.

   b. Adjust area load power factor until VAR Export out of the subject area is zero for contingency determined above. Note: A uniform load power factor must be applied (i.e. the same load power factor must be applied to each bus in the area).

   c. The area load power factor at which the VAR export out of the area is zero constitutes the maximum load power factor based on the Zero VAR Interchange criterion.

4. **Voltage Criteria Testing –** For each load level, the maximum load power factor based on voltage criteria is to be determined as follows:

   a. Determine contingency that results in the highest transmission voltages in the subject area.

   b. Adjust area load power factor until a significant number of transmission busses (69 kV and above) do not exceed the design criteria of Transmission Owners in the area. This power factor constitutes the maximum load power factor for the area based on voltage criteria. Note: A uniform load power factor must be applied (i.e. the same load power factor must be applied to each bus in the area).

5. **Limiting Power Factor –** For each load level, the most restrictive load power factor (based on either Zero VAR Interchange or Maximum Voltage), becomes the area standard.

VI. REPORT

A report shall be written for each area, documenting all analysis conducted to determine the load power factor requirements. The report shall include the following:

- Interface Definition (i.e. list of branches that define the subject Area)

- Contingency List

- Base Case Summaries for all 4 load flows developed:

  1) MW and MVAr Output of all major generators in the New England Control Area
  2) Dispatch of all Transmission Capacitors in the subject Area.
  3) Dispatch of all Transmission Reactors in the subject Area.
  4) Interface flows (MW) for all relevant transmission interfaces in the New England Control Area.
  5) The New England Control Area Load (GW)
  6) HVDC Transfer Levels (MW)

- Figure 1.2 is a sample of the table, which itemizes the minimum and maximum power factor case results for each load level.

Figure 1.2: Sample Report Table

		(MVAR)										(MW)							
		Supply					Demand					Supply			Demand				
Loadflow Description	Limiting Contingency	Line Charging	Area Generators:Combined MVAr Output	Area Xmission Capacitors: Combined MVAr Ouput	Tie Lines: Combined MVAr Import	Total MVAr Supply	Line Losses (I^2X)	Area MVAr Load	Area Xmission Reactors: Combined MVAr Absorbsion	Station Service MVAr Load	Total MVAr Demand	Area Generators:Combined MW output	Tie Lines: Combined MW Import	Total MW Supply	Area MW load	Station Service Load	Area MW Losses (I^2R)	Total MW Demand	Area LPF
NE MA 100% Load LV Bias	394	338	300	1465	20	2123	1758	365	0	0	2123	2494	-307	2187	2100	0	87	87	0.985
NE MA 75% Load LV Bias	394	378	305	1197	5	1885	1221	659	0	0	1880	1976	-339	1637	1565	0	72	72	0.920

The Low Load/Low Voltage Bias and Peak Load/High Voltage Bias was removed.

NE MA 75% Load HV Bias	Granite Ridge	241	-78	621	-38	746	693	-267	320	0	746	1416	165	1581	1565	0	16	16	0.985
NE MA 35% Load HV Bias	Salem G3	294	-41	446	11	710	228	2	480	0	710	589	267	856	852	0	4	4	1.000

OP 17 Appendix B Revision History

Document History (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

Rev. No.	Date	Reason
Rev 1	03/07/03	
Rev 2	02/01/05	Updated to conform to RTO terminology
Rev 3	06/02/05	Revised data resulting from Voltage Task Force review
Rev 4	09/07/06	Update for changes resulting from VTF meetings
Rev 5	10/01/06	Revised for ASM Phase 2

Appendix 11

Further Reading Bibliography

APPENDIX 11 – Further Reading Bibliography

(Rev. 5/14/2009)

In alphabetical order;

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