NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

NERC Operating Manual

March 2012

RELIABILITY | ACCOUNTABILITY

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A History of NERC

1962 — The Interconnected Systems Group (ISG), comprised of utilities located in the Midwest and South, met to prepare for the imminent closure of seven interconnections to form the largest synchronized system in the world. The systems to be included were the four regions of the ISG (Northeast Region, Southeast Region, Northwest Region, and Southwest Region), Pennsylvania-New Jersey-Maryland Interconnection, and Canada-U.S. Eastern Interconnection (CANUSE). The Interconnection Coordination Committee (ICC) was formed to study and recommend an informal operations organization for the future. The North American Power Systems Interconnection Committee (NAPSIC) was formed that adopted the recommendations of the ICC. It served as an informal, voluntary organization of operating personnel that included the ISG regions, the four areas that now comprise WSCC, and ERCOT.

1965 — A blackout occurs in the northeastern United States and southeastern Ontario, Canada.

1967 — The U.S. Federal Power Commission report on the blackout recommended "A council on power coordination made up of representatives from each of the nation's Regional coordinating organizations to exchange and disseminate information on Regional coordinating practices to all of the Regional organizations, and to review, discuss, and assist in resolving matters affecting interregional coordination."
— Legislation proposed: Electric Power Reliability Act of 1967

1968 — Twelve Regional and area organizations form the National Electric Reliability Council (NERC) when they sign an agreement on June 1. On August 19, the chairman of the NERC Executive Board writes to the NERC Regions appointing an ad hoc committee on operations and an ad hoc committee on planning and coordination to study and recommend the need for other committees for NERC.

1970 — NERC opens its administrative office in New York City on January 1, and in May, moves to Princeton, New Jersey.

Four organizations in the Southeast combine to form the Southeastern Electric Reliability Council. NERC now has nine Regional Councils.

1975 — NERC incorporates as a nonprofit corporation in New Jersey.

1978 — The Board of Trustees agrees on several additional organizational objectives for NERC, including the need to: define and measure reliability, analyze and testify about legislation affecting reliability, study interregional interconnections, communicate with and educate others about reliability, and collect and publish data on future electricity supply and demand.

1979 — NERC assumes responsibility for collecting and analyzing generator availability data from the Edison Electric Institute's (EEI) Prime Movers Committee. NERC, with support from the Electric Power Institute, restructures EEI's Equipment Availability Data Reporting System to create the Generating Availability Data System (GADS).

NERC approves expanding its activities to address changes in the industry resulting from the passage of the U.S. National Energy Act of 1978. These activities include the development of planning guides for designing bulk electric systems, invitations to utility trade groups to send observers to NERC Board meetings, and adding staff to support expanded technical activities.

1980 — The North American Power Systems Interconnection Committee merges with NERC and becomes the NERC Operating Committee. The NERC Technical Advisory Committee (TAC) becomes the NERC Engineering Committee.

1981 — To recognize the Canadian membership in the Regional Councils, NERC changes its name to North American Electric Reliability Council, keeping the acronym NERC.

1983 — Alaska Systems Coordinating Council becomes NERC's first affiliate member.

1986 — EEI transfers the integrated Hourly Load Data Base to NERC. NERC expands the database to include all ownership sectors of the electric utility industry.

1987 — At the urging of the U.S. government's National Security Council and Department of Energy, NERC forms the National Electric Security Committee to address terrorism and sabotage of the electricity supply system.

1990 — Congress passes the Clean Air Act Amendments of 1990. NERC uses the GADS database to provide the Energy Information Administration with a summary of forced and planned outages in the 1985–87 period. EPA uses the GADS data to set generator unit emission allocation values.

1992 — Congress passes the Energy Policy Act of 1992. The "NERC Amendment" in the Act bars the federal government from ordering transmission service if the order "would unreasonably impair the continued reliability of electric systems affected by the order."

1993 — The Future Role of NERC Task Force, appointed by the Board of Trustees in 1992 to address provisions of the Energy Policy Act of 1992, develops an action plan for the future. The resulting report, *NERC 2000*, includes: Policies for Interconnected Systems Operation, Policies for Planning Reliable Bulk Electric Systems, Membership Recommendations, and Policies for Dispute Resolution.

1994 — Legislative and regulatory initiatives directed at the industry encourage competition through participation in the electricity marketplace by many new entities. The Regional Councils open their memberships to these new participants including independent power producers, power marketers, and electricity brokers. The NERC Board adds two voting Trustees positions for independent power producers.

NERC develops a set of principles for scheduling electricity interchange transactions — "Agreements in Principle on Scheduled Interchange" — that apply equally to electric utilities, power marketers, and other purchasing-selling entities.

1995 — The Federal Energy Regulatory Commission issues its Notice of Proposed Rulemaking (NOPR) on Open Access seeking comments on proposals to encourage a more fully competitive wholesale electric power market. NERC took the lead in addressing the planning and operating reliability aspects of the NOPR and filed a six-point action plan to provide the basis for action by the electric utility industry and FERC.

1. Establish standards for "Available Transfer Capability,"
2. Reflect actual path flows in interchange scheduling to ensure continued reliability,
3. Ensure control area operators have clear authority in emergencies,
4. Ensure compliance with NERC rules in a comparable and fair manner,
5. Establish standards for Interconnected Operations Services, and

6. Ensure that information vital to operational security is shared freely among control areas, but is not available to gain unfair market advantage.

1996 — NERC opens its board and committees to voting participation by all industry segments, including power marketers and independent power producers.

1997 — NERC formed the Electric Reliability Panel, an independent body, to recommend how NERC should redefine its vision, functions, governance, and membership to ensure that reliability could be maintained in an increasingly competitive marketplace. The panel's report called on NERC to restructure itself into a new organization called the North American Electric Reliability Organization (NAERO) that could function as a self-regulating organization with the authority to set, measure, and enforce reliability planning and operating standards.

The board approved NERC's first Planning Standards, replacing Planning Guides and a "due process" for developing Operating Standards.

NERC developed two coordinated programs to establish standards for the training and qualifications of persons who operate the bulk electric systems of North America — System Operator Certification Program and System Operator Training Accreditation Program. NERC and Commercial Practices Working Group (an industry group addressing electricity marketplace issues) and NERC Regional Reliability Coordinators worked together to build a more viable and reliable marketplace. The Operating Committee put into place a Transaction Information System that provides a method for "tagging" all interchange transactions. The tag provides information to identify and track the purchase and sale of electricity so that the reliability of the system can be maintained.

1998 — NERC board approved the basic elements of a mission and purpose statement for NAERO, defined the composition of NAERO's board, and set forth NAERO membership requirements. It also approved key elements of agreements between NAERO and its affiliated Regional Reliability Organizations and approved formation of an Interim Market Interface Committee to review NERC reliability policies and standards for impacts on commercial markets. This committee is now called the Market Committee. The board voted in favor of consensus legislative language, which would permit NERC to become a self-regulatory organization. In addition, NERC agreed, at the request of the U.S. Deputy Secretary of Energy, to lead the electric industry's efforts to assess and report on the industry's readiness to deal with Y2K issues.

1999 — NERC elected nine independent members to the Board of Trustees to succeed the industry stakeholder board after reliability legislation was enacted in the United States. It also appointed a special steering committee to develop an action plan to implement the next steps in the process of enacting the NERC Consensus Legislative Language on Reliability. Other actions taken:

1. NERC coordinated the electric utility industry's preparations for the Year 2000 (Y2k).
2. The board disbands the old standing committee and created three new standing committees whose members represent all sectors of the industry
3. NERC initiated standards and compliance procedures and launched a pilot compliance program. Objectives were to test the effectiveness of NERC and Regional compliance review procedures and to test compliance with 22 NERC standards and their associated measurements.
4. NERC initiated a second-generation (electronic) tagging system to avoid problems inherent in email systems and protocols.
5. NERC certified almost 2,400 system operators under its System Operator Certification Program, which tested their understanding of NERC Operating Policies. By 2001, all system operators on duty had to be NERC-certified.
6. NERC initiated a new approach to project management. NERC staff would provide technical support

and project management to implement the decisions and directives of the respective standing committees.
7. NERC released its *Study on NOx Rule*, which assessed the potential impact of certain Clean Air Act requirements in the on bulk electric system reliability.

2000 — NERC agreed to serve as the electric utility industry's primary point of contact with the federal government for issues relating to national security and critical infrastructure protection. As part of this effort, NERC became a founding member of the Partnership for Critical Infrastructure Security (PCIS), which coordinates cross-sector initiatives and complements public/private efforts to promote and assure reliable critical infrastructure services. NERC also significantly increased its outreach to government officials in both the United States and Canada, reflecting the critical role governments play in the restructuring of the electric utility industry. In addition:

1. NERC and FERC take major step toward improving coordination and communication between the two organizations with the execution of a "Consultation and Communications Protocols," which calls for increased FERC participation at NERC board and committee meetings and periodic discussions between the FERC chairman and NERC executives
2. NERC sponsored a long-term planning initiative to address market-reliability interface issues. The issues identified were molded into action plans and approved by the board.
3. Control Area Criteria Task Force defined basic operating reliability functions that can be rolled up into other entities. The concepts discussed in its report will serve as the basis for new operating policies and standards.
4. Board charged the Standards Task Force with recommending changes to the NERC reliability standards and the process used to develop them.
5. NERC Compliance Enforcement Program (CEP) completed the second year of a multi-year phase-in.

2001 — In the absence of legislative authority, nine of the ten Regional Reliability Councils signed an Agreement for Regional Compliance and Enforcement Programs with NERC. The agreements are intended to enforce compliance with NERC reliability rules through contractual means. Although the Agreements are not a substitute for federal legislation, they allow NERC to ensure some measure of compliance with some of the rules.

The NERC board revised its bylaws to change its governance to a ten-member Independent Board of Trustees from a 47-member Stakeholder Board, despite the fact that Congress failed to adopt proposed reliability legislation.

NERC passed several resolutions to approve a functional operating model, ensure the independence of the reliability coordinators, and initiated a transition to organization standards.

1. NERC Operating Committee designed a model that defines the basic functions for reliable bulk electric system operations. With these functions defined, NERC can write standards to address each of function. Then, as new organizations, such as regional transmission organizations (RTO), independent system operator (ISO), and independent transmission companies, develop, they will register the functions they perform with NERC as well as the standards that they will need to comply with.
2. The NERC Compliance Enforcement Program completed audits of all Reliability Coordinators (RCs) by the end of 2000 focusing on all aspects of RC responsibilities
3. NERC developed a series of new control area criteria, operating policies, and planning standards. The control area criteria establish the requirement for qualification as a NERC-certified control area.
4. The Standards Task Force (STF) was established to redesign the process by which NERC standards are developed. NERC will use the new standards development process to prepare new organization standards.

2002 — NERC continued to work to improve the electric industry's physical and cyber security and to provide a common point for coordination with the U.S. government by forming the Critical Infrastructure Protection Advisory Group. The Group developed a compendium of security guidelines for the electricity sector for protecting critical facilities against a spectrum of physical and cyber threats and established the Electricity Sector Information Sharing and Analysis Center.

It also established a Critical Spare Equipment Database, replacing a smaller, limited database and with support from the U.S. Department of Energy is designing a standardized public key infrastructure implementation plan for the industry. NERC also designed and implemented a new reliability standards development process for the industry.

1. NERC-NAESB Coordination. NERC is responsible for developing reliability standards, while the North American Energy Standards Board (NAESB) develops business practice standards and electronic communications protocols for the wholesale electric industry. In recognition of the close relationship between reliability standards and business practice standards, NERC and NAESB signed a memorandum of understanding that details the coordination between the two organizations. A Joint Interface Committee (JIC), comprising representatives of NERC and NAESB, was created to examine each standard proposal that is submitted to NERC or NAESB to determine which organization should develop the standard.
2. Organization Certification. The functional model identifies the functions that need to be performed to ensure the reliable planning and operation of the grid. Some of the entities that expect to perform these functions will need to be certified, similar to the way control areas are certified today. The new reliability standards will identify reliability responsibilities along with the certification requirements for these functions.
3. Personnel Certification. The System Operator Certification Program was expanded to offer four credentials for specialized testing in the following areas: balancing and interchange, transmission, balancing/interchange and transmission, and reliability coordinator. The program provides enhanced individual utility training, self-study workbooks, computer training programs, and support workshops. To date, more than 4,300 individuals have attained a NERC certification credential.
4. Reliability Coordinator Audits. By the end of 2002, the Compliance Enforcement Program (CEP) had audited all NERC Reliability Coordinators. The audits focused on all aspects of the Reliability Coordinator responsibilities. Overall, the audit teams found that Reliability Coordinators are acting effectively and independently to preserve the reliability of the bulk electric system.
5. NERC, in conjunction with the Consortium for Electric Reliability Technical Solutions (CERTS), developed and implemented an area control error (ACE) and an area interchange error (AIE) real-time monitoring system applications for North America. These applications enable the reliability coordinators to monitor ACE-frequency performance and compliance with performance operational guides as well as allow NERC to analyze and assess control data to improve reliability performance.
6. Assuring the reliability of new generator connections. FERC issued a NOPR on Standardization of Generator Interconnections that included a draft agreement designed to standardize and streamline the generator interconnection process. NERC filed comments suggesting that further work is required to ensure that the reliability requirements outlined in the NOPR are consistent with NERC reliability standards and not affect the reliability of the bulk electric system.
7. NERC board approves and implements a new process for developing reliability standards. A Standards Authorization Committee is created and a NERC standards director is appointed.

2003 — NERC board adopted two more electric sector critical infrastructure protection security measures dealing with securing remote access to electronic control and protection systems and threat and incident reporting. The board adopts the first standard to emerge from the new standards development process.

1. The new reliability standards development process receives ANSI-accreditation.
2. NERC receives and process 18 standard authorization requests. Several standards move into the development phase.
3. NERC adopts a cyber security standard, the first standard to be developed through the new standards development process, approved by the industry, and adopted by the board.

The Future — NERC's strength lies in its ability to enlist the expertise of qualified individuals working in the electric supply systems of the United States and Canada. NERC will continue to help the electric industry work together "to keep the lights on." Reliable interconnected electric systems are a prerequisite for a competitive electricity industry, and NERC has "taken the lead" and is working actively to ensure its "rules" for reliable electric system operation, such as these Operating Policies, are established and applied in a fair and nondiscriminatory manner.

NERC Regional Entities

A geographical map of the NERC Regional Entities is available at http://www.nerc.com/page.php?cid=1|9|119.

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Organization and Procedures Manual for NERC Standing Committees

Approved by the Board of Trustees on June 15, 2004

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Introduction

NERC Mission

The North American Electric Reliability Council's (NERC's) mission is to ensure that the bulk electric system in North America is reliable, adequate, and secure. NERC accomplishes this mission by:

- Setting and enforcing standards for the reliable planning and operation of the bulk electric system.
- Certifying reliability service organizations and personnel.
- Assessing the historical and near-term reliability, and future adequacy of the bulk electric system.
- Providing reliability training and education resources.
- Facilitating information exchange, system modeling, and analytical methods and tools as needed for reliability.
- Interfacing with organizations in industry and agencies of the federal, state, and provincial governments in North America on reliability matters.
- Working with industry and government to coordinate the physical and cyber security of electricity infrastructure.

Corporate Overview

NERC is a not-for-profit corporation whose owners and members are the ten Regional Reliability Councils (Regional Councils). NERC is governed by an independent Board of Trustees elected by the Stakeholders Committee.

The members of the Regional Councils are from all segments of the electric industry — including investor-owned, federal, rural electric cooperatives, state, municipal, and provincial systems, exempt wholesale generators (independent power producers), and power marketers. These entities account for virtually all of the electricity supplied in the United States, Canada, and the northern portion of Baja California Norte, Mexico.

NERC Organizational Framework

The standing committees are one part of the overall NERC organization. An overview is provided below to illustrate how the standing committees fit into the organization and to identify key relationships with other NERC functions. The remaining sections of this manual describe the standing committees in greater detail, addressing committee scopes, organization, and procedures. Additional information regarding the other NERC functions listed below may be found in separate references on the NERC web site at www.nerc.com.

- **Board of Trustees** — provides leadership and sets policy for all NERC activities. The Board is comprised of ten independent Trustees, one of whom is the NERC president.
- **Stakeholders Committee** — is a senior executive group, representing a balance of stakeholder views, whose role is to advise the Board on policy issues. The Stakeholders Committee also

serves several corporate governance responsibilities assigned in the NERC Certificate of Incorporation and Bylaws.

- **Standards Authorization Committee** — manages the development of reliability standards and is elected by and accountable to a registered ballot body of industry stakeholders. The Board provides oversight to ensure the standards process remains open, inclusive, fair and balanced.
- **Compliance and Certification Committee** — manages the assessment, monitoring, and enforcement of compliance with reliability standards. This committee also manages the certification of reliability service organizations and personnel.
- **Critical Infrastructure Protection Committee** — advises the Board on matters related to the physical and cyber security of the electricity infrastructure of North America. The Critical Infrastructure Protection Committee develops security guidelines, interfaces with industry and various government agencies on security matters, and advises the operation by NERC of the Electricity Sector – Information Sharing and Analysis Center.
- **Standing Committees** — are comprised of volunteer industry experts in issues impacting reliability. The standing committees support NERC's mission by carrying out the responsibilities stated in their scopes, by executing the policies, directives, and assignments of the Board of Trustees, and by advising the Board on reliability matters. The standing committees also advise the other NERC functions on matters requiring reliability expertise.

Manual Purpose and Applicability

This manual defines the scope, functions, representation, and procedures of the three NERC standing committees: Operating Committee, Planning Committee, and Market Committee. The manual is a living document that may be updated from time to time by approval of the NERC Board of Trustees. Changes to the manual may be recommended to the NERC Board for approval by any standing committee, with consultation of the other standing committees. The manual also applies to the subordinate groups of the three NERC standing committees.

All other NERC committees and their subordinate groups should use this manual as a procedural guide, and apply those sections of this manual that are applicable to their functions and organizational structure.

Committee Organization

Preface

One of NERC's most valuable assets is the reliability expertise provided by active participation of industry volunteers in NERC's committees and subordinate groups.

Establishment of Committees

The NERC Board of Trustees may create committees. In doing do, the Board approves the scope of each committee and assigns specific authorities to each committee necessary to conduct business within that scope. Each committee shall work within its Board-approved scope and shall be accountable to the Board of Trustees for its Board-assigned responsibilities.

Committee Scopes

NERC has three standing committees: Operating Committee, Planning Committee and Market Committee. The standing committees support the NERC reliability mission by executing the policies, directives, and assignments of the Board of Trustees, and advising the Board on reliability matters. The following functions are representative of the functions of the standing committees. A Board-approved scope outlining the responsibilities of each committee shall be available on the NERC web site. The Board may assign additional functions, as it deems appropriate. The following functions are representative of the functions of the standing committees:

- Assess resource and transmission adequacy and reliability performance.
- Provide reliability education and training resources.
- Coordinate reliability matters with Regional Councils and other organizations.
- Assess the reliability impacts of standards proposed or set by other organizations.
- Provide advice and recommendations on reliability applications, data, and services.
- Facilitate information exchange in support of reliable real-time operations.
- Assist in the development and the evaluation of the effectiveness of reliability standards.
- Provide advice and recommendations on the processes for assuring compliance and certification of reliability service organizations and personnel.
- Assess the impacts of standards and NERC activities on electricity markets and promote market solutions for reliability.
- Advise the NERC dispute resolution function.

Committee Scope Revisions

If the members of an existing committee determine that the committee's scope of work should be revised, the committee shall submit recommendations accordingly to the Board of Trustees for approval.

Committee Representation

General

Each committee shall have a defined membership composition that is approved by the Board. Membership composition may be unique to each committee. Although NERC committees historically have had fixed memberships, open membership may be appropriate in some cases, with Board approval. Membership composition of committees may evolve to meet changing needs of NERC and reliability stakeholders.

Each committee may propose for Board approval revisions to its membership composition. Each committee shall strive to maintain a membership composition that accomplishes two objectives:

- Balance representation among all stakeholders impacted by the work of the committee, consistent with NERC principles of being open, inclusive, and fair. Balance should include such factors as industry segment, region, Interconnection, and country. No one segment should be able to block or veto committee action, and no two segments should be able to form a sufficient majority to carry a committee motion.
- Provide expertise sufficiently robust to achieve technical excellence in fulfilling the scope and responsibilities of the committee.

The Board of Trustees may modify the committee membership composition or appoint additional voting or non-voting members to a committee, as it deems necessary to achieve these objectives.

Standing Committee Memberships

The membership composition of the Operating, Planning, and Market Committees is currently defined as follows:

- Voting Members (35)
  - Chairman (1) and Vice Chairman (1)
  - Regional Reliability Council (RRC) Representatives (13)
    - Eastern Interconnection (9) (Including 1 from Eastern Canada)
    - Western Interconnection/WECC (3) (Including 1 from Western Canada)
    - Texas Interconnection/ERCOT (1)
  - Other At Large Canada Representatives (2)
  - Stakeholder Segment Representatives (18)
    - Independent System Operator/Regional Transmission Operator (2)
    - Investor-Owned Utility (2)
    - Federal (U. S.) (2)
    - Transmission Dependent Utility (2)
    - State/Municipal Utility (2)
    - Cooperative (2)
    - Merchant Electricity Generator (2)
    - Electricity Marketer (2)
    - End-use Electricity Customer (2)

- Non-Voting Members
  - Regulator (State and Provincial) Representatives (4)
    - Western (1)
    - Eastern (1)
    - Texas (1)
    - Canada (1)
  - Regulator (Federal) Representatives (2)
    - U. S. Federal Energy Regulatory Commission (1)
    - Canada National Energy Board (1)
  - Observer Representatives (Same as Board Observers)
  - Committee Secretary (NERC Staff Coordinator)
  - Prior Chairman (*ex officio* non-voting member, at the discretion of the chairman)

Committee Member Terms

Unless otherwise stated in the specific requirements of a committee, committee members, including non-voting members, shall have a term of two years. To assure continuity, terms should be staggered to allow about half of the members' terms to expire each year. The terms of committee officers need not be staggered.

Prior Chairman

At the discretion of the current chairman, the immediately prior chairman may serve *ex officio* as a non-voting member of the committee.

Committee Membership

Principles

Committee members shall be nominated and selected in a manner that is open, inclusive, and fair. All committee member appointments shall be approved by the Board of Trustees and committee officers shall be appointed by the Board chairman.

Procedure for Appointing Committee Members

Each committee with a fixed membership composition shall maintain a Nominating Task Force, whose responsibilities are described below and later in this manual.

Each committee with a fixed membership shall conduct an open nominations process to receive nominations to fill any membership vacancies. Generally this process will be conducted annually to replace members whose terms are expiring.

NERC staff shall, under the oversight of the Technical Steering Committee or a committee chairman, administer the nominations process. The nominations process should be conducted jointly across committees when vacancies are being filled across multiple committees. The Technical Steering Committee, whose responsibilities are defined later in this manual, shall oversee the conduct of the nominations process when more than one committee is involved. The committee chairman shall oversee the conduct of the nominations process when only one committee is involved.

A request for nominations should specify the committee positions to be filled, the qualifications for filling each position, and additional considerations in evaluating candidates, such as areas of expertise needed on the committee.

Generally a request for nominations should provide a window of at least 30 days for submission of nominations. Shorter nominating periods may be necessary on an exception basis if there is an urgent need in the view of the Technical Steering Committee or committee chairman, as applicable.

NERC staff shall forward nominations received to the Nominating Task Force of each respective committee. The Nominating Task Force shall fairly evaluate the nominees using criteria established in the solicitation and the best judgment of the task force on how best to fulfill the membership needs of the committee. The Nominating Task Force shall then prepare its recommended slate of members and indicate the terms of each member and candidate.

The Nominating Task Force shall present the recommended committee membership slate to the Board for approval. The Nominating Task Force may present the proposed slate to the committee for information purposes before submitting the slate to the Board, but the committee does not act on the slate.

The Board of Trustees, by virtue of approving a committee slate, appoints each voting and non-voting committee member. The Board may also appoint members individually as needed for replacement.

Procedure for Appointing Committee Officers

The process for appointing committee officers is similar to that previously described for committee members, except for the approval steps. With due consideration of the open nominations process

described above, the Nominating Task Force shall prepare a slate of officer candidates and present the proposed slate for the committee to consider. The committee shall consider the recommended slate of the Nominating Task Force and any additional nominations the members may offer from the floor, and approve a recommended slate of officers. The committee shall present the slate of committee officers to the chairman of the NERC Board of Trustees, who shall appoint committee officers with due consideration of the committee's recommended slate.

General Criteria for Membership

The Nominating Task Force shall consider the following general criteria, in addition to specific committee membership requirements, in preparing a recommended slate:

- Each Regional Council shall appoint committee members that are designated as representing their region. Regional Council representatives should be capable of representing the region in committee activities.
- The Canadian Electricity Association shall appoint Canadian representatives. Canadian representatives should be capable of representing Canada in committee activities.
- Industry stakeholder segments may elect their segment representatives through an open process approved by the NERC Board of Trustees, with a balance of Interconnection and geographic considerations as appropriate. Otherwise, the Nominating Task Force may give preference to candidates nominated by organizations representing a broad cross section of an industry segment, such as an industry trade association.
- No individual may serve concurrently on more than one standing committee.
- No two individuals from the same organization, or affiliated organizations, may serve concurrently on one standing committee.
- No more than two individuals from the same organization should serve concurrently on the several standing committees.

Replacement of Resigning or Non-participating Members

In the event a voting or nonvoting member can no longer serve on the committee, that member shall submit a written resignation to the committee chairman or secretary.

The chairman should request any committee member who ceases to participate in the committee, as indicated by not attending or sending a proxy for two consecutive meetings, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within 30 days of the chairman's request, the lack of response should be considered a resignation.

The committee chairman shall refer the vacancy resulting from a resignation to the Nominating Task Force. The nomination and selection of replacement members shall be conducted in an open, inclusive and fair manner, using a process similar to that used for the annual membership solicitation. The Task Force shall request NERC staff to prepare a solicitation for nominations to fill that position. The Nominating Task Force shall follow the previously stated criteria in recommending a replacement.

The committee chairman may seek a vote of the committee to allow the proposed replacement member to be seated pending appointment of the replacement at the Board's next scheduled meeting.

Changes in Member Affiliation

A committee member who moves from one organization to another shall have the option of retaining the membership position if the new organization is in the same constituency (industry segment, region, etc.) and no membership conflicts are created per the General Criteria for Membership. If the new affiliation changes the member's constituency, then the member shall resign from the committee.

If the change in affiliation results in two members from the same organization on a committee, or other conflict with membership criteria stated in this manual, those two members should identify who will stay on the committee and who will resign. The committee chairman shall act to address the conflict by removing one of the members from membership, if the members do not resolve the conflict within 30 days.

Acknowledgement of a Membership Conflict

Any committee member who knows of any form of membership conflict, such as working for an entity affiliated with that of another committee member, shall notify the committee chairman within ten (10) business days of obtaining that knowledge.

Committee General Procedures

Conduct of Meetings

In the absence of specific provisions in this manual, all committee meetings shall be conducted in accordance with the most recent edition of Robert's Rules of Order in all cases to which they are applicable.

Presiding Officer

The committee chairman shall preside at a committee meeting or designate the vice chairman or another committee member to preside. The presiding officer of a meeting is designated below as the "chair" rather than the chairman, since the presiding officer may or may not be the committee chairman.

Calling of Meetings

Generally, the standing committees shall conduct three meetings per year, coordinated to be in the same location and to be concurrent or sequential as needed to address common business. Each committee chairman may call for additional meetings as needed to accomplish the assigned responsibilities of the respective committee.

Meeting Locations

To facilitate travel associated with meetings, all committees and subordinate groups shall exercise good judgment in selecting meeting locations by considering cost, travel time, and convenience for all participating members and observers.

Open Meetings

NERC committee meetings shall be open to the public, except as noted below under Confidential Sessions. Although meetings are open, action on items before a committee shall be determined only by the voting members of the respective committee.

All persons not otherwise affiliated as voting or non-voting members of the committee shall be designated as committee guests. Committee guests shall not be permitted to vote and shall have no bearing on the existence of a quorum. It shall be the chair's prerogative to determine whether and when it is appropriate to include the comments and questions of the committee guests in the proceedings of the committee.

Confidential Sessions

The chair of a committee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties. A preference, where possible, is to avoid the disclosure of sensitive or confidential information so that meetings may remain open at all times. Confidentiality agreements may also be applied as necessary to protect sensitive information.

Meeting Registration

All committee members, observers, and guests must register in advance for any meeting of the committee for which registrations are required. Advance registration allows preparation of adequate accommodations suitable for conduct of committee business.

Antitrust

All persons attending or otherwise participating in a NERC committee meeting shall act in accordance with NERC's Antitrust Compliance Guidelines at all times during the meeting. A copy of the NERC antitrust statement shall be included with each meeting agenda.

Quorum

The quorum necessary to transact business at meetings of a committee shall be two-thirds of the voting members of the committee, excluding any vacant positions. Voting members approved by the committee on an interim basis pending confirmation by the Board shall be counted in the determination of a quorum.

If a quorum is not present, then the committee may not take any actions requiring a vote of the committee. However, the chair may, with the consent of the members present, elect to allow discussion of agenda items.

Voting Procedure

Committee action requires a two-thirds majority of the votes cast at a meeting in which a quorum is present. For the purpose of determining a two-thirds majority, abstentions do not count. Therefore the vote to approve a motion is calculated as the affirmative votes divided by the sum of the affirmative votes and the negative votes.

Each voting member of the committee shall have one vote and may not serve as the proxy of another member.

The chairman and vice chairman of each committee shall be voting members of their respective committees and may choose, at their discretion, to vote on any action of the committee.

Non-voting members, observers, and guests shall not be allowed to vote, unless serving as a proxy for a voting member.

Majority and Minority Views

Consistent with this manual and Robert's Rules of Order, all members of a committee should be afforded the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, shall reflect the majority as well as any minority views of the committee members. The chairman shall communicate both the majority and any minority views in presenting results to the Board of Trustees.

Proxies

A substitute representative, or proxy, may attend and vote during all or a portion of a committee meeting in lieu of a voting member, provided the absent member notifies the committee chairman, vice chairman, or secretary of the proxy. Such notification shall be in writing (electronic medium is acceptable). The proxy representative and his or her affiliation shall be named in the correspondence.

A voting member of a committee may not serve as a proxy for another voting member on the same committee (a member may not carry more than one vote).

Notice of Committee Agenda

The publication of an agenda of actions to be voted upon by the committee shall include the precise wording of any proposed motion. The sponsor of the motion shall prepare a brief description of the justifications for the motion and other information that would be useful to committee members in considering the motion.

In general, action may not be brought to a vote of the committee unless it has been noticed in a published agenda or other form of distribution to the committee at least ten (10) business days before the meeting date upon which action is to be voted. This requirement for a 10-day notice may be waived either by the approval of the chair or by a two-thirds affirmative vote of the committee's voting members present at a committee meeting at which a quorum has been established.

Action without a Meeting

Any action required or permitted at a meeting of the committee may be taken without a meeting if a two-thirds majority of the committee members entitled to vote on the action approves taking the action outside of a meeting.

Such action without a meeting shall be performed by mail or electronic ballot (e.g., telephone, facsimile, e-mail, or Internet). Written notice to the committee members of the subject matter for action is required not less than ten (10) business days, nor more than sixty (60) calendar days prior to the date on which the action is to be voted. As time permits, members should be allowed a window of ten (10) business days to vote. Committee members shall receive written notice of the results of such an action within ten (10) business days of the close of the voting period. All responses of the committee members shall be filed as a roll call vote with the committee minutes.

Such action without a meeting shall not preclude the Executive Committee of a committee from exercising the powers of the committee between meetings of the committee as described later in the section on Executive Committees.

Meetings by Telephone and Electronic Media

Working groups, task forces, and other small groups are encouraged to use telephone conference calls and electronic media such as the Internet and email to conduct their business. These alternatives are particularly suitable when the group size is manageable for the selected medium and when the agenda is simple and only a few actions are anticipated.

Face-to-face meetings are encouraged, however, for larger groups and complex agendas with multiple action items. Meeting in person ensures sufficient opportunity to debate alternative views and resolve issues. In general, standing committee meetings should be conducted in person. Subcommittee meetings should also be conducted in person, unless the agenda is manageable for an alternative medium.

For face-to-face meetings, all members are responsible for attending in person or providing a proxy. Participating by telephone in a face-to-face meeting of a committee or subcommittee is discouraged and shall be allowed only at the discretion of the chairman of the committee or subcommittee. Telephonic participation in working group or task force meetings may be practical, but shall be at the discretion of the group chairman.

Dispute Resolution

Each committee shall strive to resolve any and all disputes that may arise in the conduct of committee business by using the procedures in this manual and in Robert's Rules of Order to resolve such disputes. Any committee member or group of members involved in a dispute shall notify the chairman in writing regarding the specific details of the dispute, including any procedural errors or unfair actions believed to have occurred and any adverse consequences. Each committee member or group of members involved in the dispute shall apply a best effort to resolve the dispute under the guidance of the committee chairman. The dispute may be resolved using whatever methods the chairman may deem appropriate, consistent with this manual and Robert's Rules of Order. If, after notifying the committee chairman of the dispute, a committee member or group of members deems that the dispute cannot be resolved by working further with the chairman, the member or group of members shall have the right to submit a grievance to the NERC General Counsel, requesting action under an applicable NERC dispute resolution program.

Responsibilities of Officers, Executives, and Members

Committee Chairman and Vice Chairman Responsibilities

The chairman of the NERC Board of Trustees appoints the chairman and vice chairman of each standing committee, with due consideration of each committee's recommended slate of officers. A committee's chairman and vice chairman are appointed to serve two-year terms and may be reappointed for succeeding terms at the discretion of the Board chairman.

The chairman and vice chairman of a standing committee are responsible to the NERC Board of Trustees. They serve at the pleasure of the Board chairman and may be replaced by the Board chairman at any time. Appointment by the Board chairman is intended to ensure the committee chairman and vice chairman are responsive to the Board, including representing both majority and minority views to the Board.

If the members of a committee, or a portion thereof, wish to challenge the continued tenure of either or both committee officers, those members may present just cause for termination to the Board for consideration.

The vice chairman shall assume the responsibilities of the chairman in the absence of the chairman or if the chairman position is vacated for any reason. A committee vice chairman may succeed to a committee chairman, if so appointed by the Board chairman.

Each committee chairman and vice chairman shall be a voting member of their respective committee. However, while acting in any aspect of committee business, they shall strive to not represent specific regions or segments, or any other electric industry entities. The officers shall, as appointees of the Board chairman, fairly represent the views of the committee, including both majority and minority views.

In addition to the duties, rights, and privileges discussed above and elsewhere in this manual, the chairman shall have the following responsibilities:

- Provide general supervision of committee activities.
- Coordinate the schedule of all committee meetings including approval of meeting duration and location.
- Develop committee agendas, and rule on any deviation, addition, or deletion from a published agenda.
- Preside at committee meetings or appoint a presiding officer when not available.
- As presiding officer, manage the conduct of committee meetings, including the nature and length of discussion, recognition of speakers, motions, and voting.
- As presiding officer, recognize proxies at committee meetings.
- Act as spokesperson for the committee at forums within and outside NERC.
- Serve as a member of the Technical Steering Committee of NERC.
- Attend meetings of the NERC Board of Trustees and report to the Board on committee activities.
- Report on both minority and majority opinions on items brought by the committee to the Board for information or action.

- Perform other duties as directed by the NERC Board of Trustees.

The vice chairman shall assume the responsibilities of the chairman under the following conditions: a) at the discretion of the chairman (for brief periods of time); b) when the chairman is absent or temporarily unable to perform the chairman's duties; or c) when the chairman is permanently unavailable or unable to perform the chairman's duties. In the case of a permanent change, the vice chairman shall continue to serve until a new chairman is appointed by the chairman of the NERC Board of Trustees.

In addition to the duties, rights, and privileges described above and elsewhere in this manual, the vice chairman shall have the following responsibilities:

- Assist the committee chairman as called upon.
- Serve as a member of the Technical Steering Committee of NERC.
- Attend meetings of the Board of Trustees.

Secretary Responsibilities

At the first regularly scheduled committee meeting following the appointment of a new committee chairman or the reappointment of a committee chairman, the committee shall elect a member of the NERC staff to serve as secretary of the committee. The committee secretary shall not have the power to vote and shall not be counted in determining the existence of a committee quorum.

In addition to the duties, rights, and privileges described elsewhere in this manual, the secretary shall have the following responsibilities:

- Serve under the direction of the committee officers, the committee's Executive Committee, and be guided by the decisions of the committee.
- Be responsible for the day-to-day operation and business of the committee.
- Prepare and distribute the notices of the committee meetings, prepare the meeting agenda.
- Within three weeks of each meeting, prepare and distribute the draft minutes of the meeting.
- Maintain a general record of all of the proceedings of the committee.
- Serve as the *ex officio*, nonvoting secretary of the committee's Executive Committee.
- Act as the committee's parliamentarian.

Executive Committee Responsibilities

Each committee shall have an Executive Committee that is comprised of the committee chairman and vice chairman, and a designated number of at-large voting members of the committee. This designated number shall be three (3), unless the committee approves an alternative number. The number of additional committee members on the Executive Committee should be large enough to fairly represent the diverse views of the committee yet small enough to be practical for urgent actions between committee meetings, and shall be a minimum of three (3) additional members. The Secretary shall serve as a non-voting member of the Executive Committee.

The committee's Nominating Task Force shall present a slate of candidates to serve as Executive Committee at-large members. The committee shall elect the at-large members of the Executive Committee at the first regularly scheduled committee meeting following the appointment of a new committee chairman or the reappointment of the committee chairman.

The Executive Committee of a committee may exercise all the powers of the full committee between meetings of the committee. It is preferred, however, to the extent practical, that the committee assigns an action to the Executive Committee in advance, or that an action is deferred to the committee as a whole. When acting between meetings, Executive Committee members should consult standing committee members as needed to obtain guidance for decisions being considered.

The Executive Committee shall notify the committee as soon as possible after the Executive Committee takes any action. The Executive Committee shall at the next full committee meeting submit any actions it has taken for ratification of the committee. If a committee does not ratify an action of the Executive Committee, that action shall nonetheless remain in effect unless and until it is modified or annulled by action of the committee.

The Executive Committee shall assist the committee chairman, as requested, in the following activities:

- Review committee meeting agendas prepared by the secretary.
- Coordinate committee and subgroup activities.
- Respond to urgent matters of the committee.
- Prepare reports to the NERC Board of Trustees.

The committee chairman may call for a meeting of the Executive Committee at any time. The chairman may also invite others to meetings of the Executive Committee as needed. An Executive Committee member who is unable to attend a meeting is encouraged to designate a proxy by providing written notice (electronic medium is acceptable) to the chairman, vice chairman, or secretary. A voting member of the Executive Committee may not serve as a proxy for another voting member (a member may not carry more than one vote).

Nominating Task Force Responsibilities

Each standing committee shall have a Nominating Task Force, whose five members shall be nominated by the committee chairman and approved by the committee, respectively. The committee chairman shall appoint the task force chairman from among the five task force members.

In addition to the duties, rights, and privileges described elsewhere in this manual, the Nominating Task Force shall have the following responsibilities:

- Prepare every two years, or as requested, a proposed slate of committee officers for the committee to consider. The committee's recommended slate of officers shall be provided to the chairman of the NERC Board of Trustees for consideration in appointing the committee chairman and vice chairman.
- Prepare a slate of three (or an alternative number specified for the committee) voting members of the committee to serve as Executive Committee members, in conjunction with the committee chairman and vice chairman. This slate shall be presented to the committee for election at the first regularly scheduled committee meeting following the appointment of a new committee chairman or the reappointment of the committee chairman. In selecting members of the Executive Committee, the Nominating Task Force should consider rotating the membership of

the Executive Committee on the basis of industry segment, Regional Council, Interconnection, country, industry segment, and other factors considered in balancing committee membership.

- Prepare annually, or as requested, a slate of voting and non-voting committee members to fill designated committee vacancies.

Committee Member Responsibilities

Each committee member should strive in all committee activities to represent the interests of the position that member fills, to the best of his or her judgment.

Non-voting members shall be full members of their respective committees in every respect, except that they shall not participate in voting, and they shall not be counted in determining a quorum.

In addition to the duties, rights, and privileges described elsewhere in this manual, each committee member shall have the following responsibilities:

- During the conduct of all committee business, act consistently at all times with the procedures in this manual and Robert's Rules of Order.
- Provide knowledge and expertise in support of committee activities.
- Seek advice and opinions from constituents represented by the committee position served by the member.
- Respond in a timely manner to all committee requests, including requests for reviews, comments, and votes on issues before the committee.
- Arrange for a proxy to attend and vote at committee meetings in the member's absence.
- Respond in a timely manner to all requests to register for committee meetings.

Subordinate Groups

Committee Organization Hierarchy

The standing committee organizational structure shall be arranged to support a superior-subordinate hierarchy that is ordered as follows:

- Committee
- Subcommittee
- Working Group
- Task Force

The committee is the superior classification within the hierarchy, other than the NERC Board of Trustees (to which each committee reports).

Each committee may establish subcommittees, working groups, and task forces when there is a clear purpose and scope to be fulfilled. The committee chairman may also form any of these subordinate groups on behalf of the committee. Formation of a committee or group requires confirmation of the chairman of the next superior committee or group in the hierarchy. For example, committee formation of a subcommittee shall be confirmed by the NERC chairman, subcommittee formation of a working group shall be confirmed by the committee chairman, and so forth.

The committee shall be the responsible sponsor of all subordinate subcommittees, working groups, or task forces it may create, or that its subordinate subcommittees and working groups may create. The committee shall keep the Board of Trustees informed of all groups subordinate to the committee.

Subcommittees

A standing committee may establish subcommittees to which certain of the committee's broadly defined continuing functions may be delegated. The committee shall approve the scope of each subcommittee it forms. The committee chairman shall appoint the subcommittee officers (typically a chairman and vice chairman) for a specific term (generally two years). The subcommittee officers may be reappointed for additional terms. The subcommittee shall be accountable for the responsibilities assigned to it by the committee and shall at all times work within its assigned scope.

Working Groups

A committee or any of its subcommittees may delegate specific continuing functions to a working group. The sponsoring committee or subcommittee shall approve the scope of each working group it forms. The chairman of the sponsoring committee or subcommittee shall appoint the working group officers (typically a chairman and vice chairman) for a specific term (generally two years). The working group officers may be reappointed for additional terms. The sponsoring committee or subcommittee shall conduct a "sunset" review of each working group every two years. The working group shall be accountable for the responsibilities assigned to it by the committee or subcommittee and shall at all times work within its assigned scope.

Task Forces

A committee, subcommittee, or working group may assign specific work of a finite duration to a task force. The sponsoring committee, subcommittee, or working group shall approve the scope of each task force it forms. The chairman of the sponsoring committee, subcommittee, or working group shall appoint the task force officers (typically a chairman and vice chairman, but a vice chairman may not be required in all cases). Each task force shall have a finite duration, normally less than one year. The sponsoring group shall review the task force scope at the end of the expected duration and at each subsequent meeting of the sponsoring group after that until the task force is retired. Action of the task force sponsoring group is required to continue the task force past its defined duration. The sponsoring group should consider promoting to a working group any task force that is required to work longer than one year.

Subgroup Membership and Representation

The membership of each subcommittee, working group and task force should be established to address the needs for expertise and balancing of interests. Each group's membership requirements shall be defined within the group's approved scope.

As a general guide, the broader the group's scope, the more emphasis there should be on balancing of interests. Therefore subcommittees would be expected to have a broader representation of industry segments, while a task force may be more focused on simply having the necessary expertise and a working group may be somewhere between.

Each member of a subordinate group, and its officers, shall be appointed by the chairman of the sponsoring committee or group. It is desirable for subgroup officers to be members of the sponsoring committee or group.

To the extent subgroup membership is of a representative nature, recommendations for staffing of the group should be provided in a manner consistent with the principles outlined in the staffing of a committee, including the use of an open nominations process. Regional Council representatives should be recommended by the Region and Canadian representatives by the Canadian Electricity Association. Preference may also be given to representatives recommended by broadly-based industry associations.

To the extent subgroup membership is based on providing requisite expertise, the chairman of the sponsoring committee or group may appoint members based on the relevant technical qualifications.

Subgroup Procedures

Subcommittees, working groups, and task forces shall conduct business in a manner consistent with all applicable sections of this manual and Robert's Rules of Order.

Inter-Committee Coordination

Technical Steering Committee

The Technical Steering Committee is a committee comprised of the chairman and vice chairman of each committee (Planning Committee, Operating Committee, Market Committee, Critical Infrastructure Protection Committee, Standards Authorization Committee, and the Compliance and Certification Committee), the chairman of the Regional Managers, and the president and senior vice president of NERC. The NERC president may on occasion invite additional persons to participate in Technical Steering Committee activities.

The purpose of the Technical Steering Committee is to facilitate the exchange of information and to coordinate activities among the committees. The Technical Steering Committee has the following functions:

- Communicate issues among committees.
- Coordinate work plans and priorities among committees.
- Coordinate meeting agendas among committees.
- Coordinate subgroup assignments and efficient allocation resources among committees.
- Coordinate the joint approval of results when more than one committee is involved.
- Prepare joint reports to the Board when more than one committee is involved.
- Identify differences among committees on particular issues and report them to the NERC president. As requested, assist the NERC president in resolving such differences.

The NERC president shall serve as chairman of the Technical Steering Committee.

Executive Committees in Joint Session

The Executive Committees of the committees may have occasion to meet in joint session, at the discretion of the NERC president or the Technical Steering Committee. The Executive Committees may periodically be assigned work by the NERC president or the Technical Steering Committee, such as evaluating proposed revisions to existing NERC planning standards and operating policies, or resolving issues common among the committees.

When the Executive Committees meet in joint session, they shall elect a chair to preside over the meeting.

When in joint session, each Executive Committee shall be allocated one vote per member or proxy present at the meeting, up to a maximum of five (5) votes per Executive Committee. In the event an Executive Committee has more than five (5) members present, the chairman of that committee shall at the beginning of the meeting designate the voting members for that meeting.

The NERC president may appoint adjunct members when the Executive Committees meet in joint session. In this case, each adjunct member carries one vote, up to a maximum of five (5). For example, the NERC president may appoint the chairman of the regional managers or officers of other NERC groups to serve with the Executive Committees in joint session, but in no case shall more than five (5) adjunct voting members be appointed.

Work Plan and Resource Coordination

Each committee shall maintain a work plan prioritizing existing and future work of the committee. The plan shall address broad committee functions as well as specific tasks assigned to the committee. The plan shall indicate target schedules for completion of milestones, and how work has been assigned to various resources of the committee.

Periodically, but no less than once per year, the Technical Steering Committee shall coordinate the work plans and resource assignments across the committees. The purpose of this review shall be to:

- Ensure functions and work assignments are properly allocated across the committees, consistent with each committee's scope.
- Ensure work is being allocated efficiently to subgroups across the committees, with no undue redundancies.
- Ensure the committees effectively integrate results on jointly shared issues.

Each chairman shall keep the committee informed of the work plan and the results of coordination with the other committees.

Committees in Joint Session

Two or more committees may, at the discretion of their chairmen, meet in a joint session. A joint session among committees may be appropriate when two or more committees need to take action on an issue and joint discussion of that action will be beneficial to the decision. During a joint session, the chairmen involved will agree which among them will chair the joint session. The committee general procedures in this manual and Robert's Rules of Order apply in a joint session of two or more committees.

When no actions are to be taken jointly by multiple committees, committees may still meet jointly, out of session, to hear informational presentations or discussions.

Resolving Differences among Committees

The Board of Trustees has assigned to the NERC president the responsibility for resolving differences among committees and for presenting to the Board both minority and majority views on these differences. In fulfilling this responsibility, the NERC president may enlist the Technical Steering Committee or others to help articulate and resolve differences.

Consistent with its scope, each committee reserves the right to review, comment, and make recommendations to the Board regarding the work of other committees.

Appendix A – Revisions to Manual

The following list summaries the revisions to this manual from May 1999 forward.

May 10, 1999 – The Interim Organization and Procedures Manual for the NERC Standing Committees was approved by the NERC Board of Trustees at its May 10, 1999 meeting. The original draft had been prepared by the Standing Committees Task Group of the NERC Board of Trustees.

February 7, 2000 – An Organization and Procedures Manual for the NERC Standing Committees was approved by the NERC Board of Trustees at its February 7, 2000 meeting. This February 2000 version was based on comments received on the May 1999 interim manual. The revisions included: a procedure for modifying the manual, the addition and formalization of a past committee chairman position and committee secretary position, the addition of guidelines (previously approved by the NERC Board in January 1999 and May 1999) to be considered in the selection or election of committee members, the change in the name of the Security Committee back to the Operating Committee, and some minor modifications and editorial changes for increased clarity and consistency.

October 12, 2000 – A revised Organization and Procedures Manual for the NERC Standing Committees was approved by the NERC Board of Trustees at its October 12, 2000 meeting. This version included the three NERC committees' recommendation to change the term of office of the officers and members of the NERC standing committees from one to two years, beginning July 1, 2001; the NERC Adequacy Committee's recommendation to change its name to the Planning Committee, effective immediately; and the associated conforming changes to the manual.

June 10, 2003 – The manual was revised to incorporate committee changes resulting from the new NERC reliability standards process, to add a section on inter-committee coordination, to clarify procedural requirements, and otherwise improve the structure and clarity of the manual.

June 15, 2004 – The manual was revised to accommodate the NERC board's June 10, 2003 approval of the new Compliance and Certification Committee, the board's February 10, 2004 decisions to: 1) change the Critical Infrastructure Protection Advisory Group to the Critical Infrastructure Protection Committee, and 2) add the chairmen and vice chairmen of the Critical Infrastructure Protection Committee, the Standards Authorization Committee, and the Compliance and Certification Committee to the Technical Steering Committee. The associated conforming changes were also made to the manual.

NERC Glossary of Terms Used in Reliability Standards

The NERC Glossary of Terms Used in Reliability Standards is available at http://www.nerc.com/files/Glossary_of_Terms_2011May24.pdf.

Control Area Criteria

The Control Area Criteria, Version 2, approved by the Board of Trustees on June 12, 2001, was superseded by Section 500 (Organization Registration and Certification) of the NERC Rules of Procedures). The NERC Rules of Procedure are posted at: http://www.nerc.com/files/NERC_Rules_of_Procedure_EFFECTIVE_20101001.pdf.

NERC Reliability Coordinator Standards of Conduct

Introduction

An entity performing the functions of RELIABILITY COORDINATOR must treat all users of the interconnected transmission systems in a fair and non-discriminatory manner. A RELIABILITY COORDINATOR must conduct its affairs in conformance with the following standards:

1. General rule.

1.1. Independence. Except as provided in paragraph 1.2 of this section, the RELIABILITY COORDINATOR, its employees, or the employees of any of its affiliates who perform RELIABILITY COORDINATOR functions ("RELIABILITY COORDINATOR employees") must operate independently of employees/persons who engage in retail (energy purchases for or sales to native load customers) or wholesale (energy purchases or sales for resale) merchant functions ("Merchant employees"). [Note: "Operate independently" does not mean or require corporate separation of the RELIABILITY COORDINATOR from the Transmission Provider or Merchant employees or merchant functions.]

1.2. Emergency actions. Notwithstanding any other provision of these standards of conduct, in emergency circumstances that could jeopardize operational security, RELIABILITY COORDINATORS may take whatever steps are necessary to maintain system security.

1.3. Reporting deviations from these Standards. RELIABILITY COORDINATORS must report to NERC and the appropriate REGIONAL COUNCIL(S) the details of any deviation from these standards of conduct, within 24 hours of such deviation. NERC staff will post the reports to the NERC RELIABILITY COORDINATOR web site.

2. Rules governing employee conduct.

2.1. Prohibitions. RELIABILITY COORDINATOR employees are prohibited from:

2.1.1. Merchant functions. Conducting Merchant functions except as outlined in 1.2 above.

2.1.2. Access to control facilities. Allowing access for Merchant employees to the system control center or similar facilities used for RELIABILITY COORDINATOR functions that differs in any way from the access available to non-affiliated TRANSMISSION CUSTOMERS.

2.1.3. Disclosing system information. Disclosing to Merchant employees any information concerning the transmission system through non-public communications conducted off the OASIS, through access to information not posted on the OASIS that is not at the same time available to non-affiliated Transmission Customers without restriction, or through information on the OASIS that is not at the same time publicly available to all OASIS users (such as E-mail). If a RELIABILITY COORDINATOR employee discloses information in a manner contrary to the requirements of this subparagraph, the RELIABILITY COORDINATOR must, as soon as practicable, post such information on the NERC RELIABILITY COORDINATOR web site and inform the affected Transmission Provider to post such information on its OASIS.

2.1.4. Sharing market information. Sharing market information acquired from non-affiliated TRANSMISSION CUSTOMERS or potential non-affiliated Transmission

Customers, or developed in the course of performing RELIABILITY COORDINATOR functions, with any Merchant employees.

2.2. **Transfers**. RELIABILITY COORDINATOR employees or Merchant employees are not precluded from transferring between such functions as long as such transfer is not used as a means to circumvent these standards of conduct. Notices of any employee transfer to or from RELIABILITY COORDINATOR functions must be reported to NERC and the appropriate REGIONAL COUNCIL(S). NERC staff will post the reports to the NERC RELIABILITY COORDINATOR web site. The information to be posted must include: the name of the transferring employee, the respective titles held while performing each function (i.e., on behalf of the RELIABILITY COORDINATOR, merchant or transmission provider, or merchant or transmission affiliate), and the effective date of the transfer. The information posted under this section must remain on the NERC web site for 90 days.

2.3. **Books and records**.

2.3.1. **Available for audit.** A RELIABILITY COORDINATOR must keep sufficient records of its activities available for audit.

2.3.2. **Separate records.** A RELIABILITY COORDINATOR must maintain its records separately from those of any affiliates and these must be available for inspection by NERC and the appropriate Regional Council(s).

3. **Rules governing maintenance of written procedures.**

3.1. **Publicly available.** A RELIABILITY COORDINATOR must provide an explanation for posting on the NERC RELIABILITY COORDINATOR web site describing the implementation of these standards of conduct in sufficient detail to demonstrate that the RELIABILITY COORDINATOR employees operate independently from merchant employees and that it is otherwise in compliance with these requirements.

3.2. **Provided to all employees.** A copy of the signed Standards of Conduct document shall be given to all employees with RELIABILITY COORDINATOR responsibilities.

AGREEMENT

As part of the process of being designated a NERC RELIABILITY COORDINATOR, [*Name of Organization*] hereby agrees to abide by the terms of the foregoing NERC Reliability Coordinator Standards of Conduct.

[*Name of Organization*]

By: _____

Title: _____

Date: _____

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

By: _____

Title: _____

Date: _____

Training Documents

Area Interchange Error Survey Training Document

Training Document Subsections

A. Effects of Area Interchange Error on the Interconnection
B. Area Interchange Error
C. Survey Procedures
D. Survey Review

A. Effects of Area Interchange Error on the Interconnection

[Policy 1A – Control and Performance]

Each CONTROL AREA is required to continually balance its generation and interchange schedules to its load (Reference: Operating Policy 1A., "Control and Performance"). The CONTROL AREA'S Area Interchange Error (AIE) is zero as long as this balance is maintained. When a CONTROL AREA fails to maintain this balance, it causes the Interconnection frequency to increase (from overgeneration) or decrease (from undergeneration). The CONTROL AREA'S AIE is equal to the imbalance.

The effect is cumulative for all the CONTROL AREAS in the INTERCONNECTION. The magnitude of the "frequency error" — the difference between actual and scheduled frequency[1] — is directly proportional to the total magnitude of the load and generation imbalances of the control areas in the INTERCONNECTION.

Actual INTERCONNECTION frequency is usually slightly above or below scheduled frequency due to the reactionary nature of generation control systems. However, when the INTERCONNECTION'S frequency error from 60 Hz remains consistently positive or negative, it causes an increasing fast or slow time error, respectively. The time error is proportional to the total magnitude *and the duration* of the load and generation imbalances of the CONTROL AREAS in the INTERCONNECTION.

A prolonged frequency error or rapid accumulation of time error indicates a significant generation/load imbalance (i.e., a non-zero AIE) in one or more CONTROL AREAS within the INTERCONNECTION. An AIE survey is a means of determining these CONTROL AREAS. All CONTROL AREAS within an INTERCONNECTION participate in an AIE survey.

This document describes the survey procedure, includes specific instructions for completing the AIE survey form and calculating the AIE, and discusses survey results.

[1]When a time correction is in effect, scheduled frequency is offset slightly from 60.00 Hz in the appropriate direction. Frequency error during a time correction will either impede or accelerate the time correction.

B. Area Interchange Error

1. **Area Control Error (ACE).** ACE is the *instantaneous* difference between the actual and scheduled interchange of a CONTROL AREA and includes a component for frequency bias. It may also include components for regulation service, electronic load or generation transfer, jointly owned generating units, and meter error. **[Appendix 1A – The Area Control Error Equation]**

The formula for calculating the CONTROL AREA'S ACE using tie line bias is:

for the Eastern and ERCOT INTERCONNECTIONS, and

$$ACE = (Ni_A - Ni_S) - 10\beta(f_A - f_S)$$

for the Western Interconnection

$$ACE = (Ni_A - Ni_S) - 10\beta(f_A - f_S) - s(0.3\,\beta_t t_d)$$

where,

Ni_A = Actual instantaneous net interchange (MW) X the algebraic sum of the power flows on the CONTROL AREA'S tie lines. Positive net interchange is a net power flow out of the CONTROL AREA.

Ni_S = Scheduled net interchange (MW) X the mutually prearranged intended net power flow on the CONTROL AREA'S tie lines. Positive net interchange is a net power flow out of the CONTROL AREA.

f_A = Actual frequency (Hz) X the actual frequency in the INTERCONNECTION.

f_S = Scheduled frequency (Hz) X the scheduled frequency in the Interconnection.

β = Frequency bias setting (MW/0.1 Hz) X the bias value used by the CONTROL AREA.

10 = A constant to convert the frequency bias setting to MW/Hz.

The following apply to the ACE equation for the Western INTERCONNECTION:

s = 1 if t_d is positive and the CONTROL AREA'S accumulation of inadvertent interchange is positive, or if t_d is negative and the CONTROL AREA'S inadvertent interchange is negative. s = 0 for all other conditions.

β_t = Time error bias (MW/0.1 Second) X the bias value used by the CONTROL AREA to correct for time error. It has the same sign and value as the frequency bias, β.

t_d = Time error (seconds). 1 second maximum.

Area Interchange Error (AIE). The formula for calculating the AIE is the same as the ACE, except that hourly integrated values are used:

$$AIE = (NI_A - NI_S) - 10\beta(F_A - F_S)$$

for the Eastern and Texas INTERCONNECTIONS, and

$$AIE = (NI_A - NI_S) - 10\beta(F_A - F_S) - s(0.3\,\beta_t T_d)$$

for the Western INTERCONNECTION

where,

NI_A = Actual net interchange (MWh) Xthe algebraic sum of the energy flows on the CONTROL AREA'S tie lines for the survey period. Positive net interchange is a net energy flow out of the CONTROL AREA.

NI_S = Scheduled net interchange (MWh) X the mutually prearranged intended net energy flow on the CONTROL AREA'S tie lines for the survey period. Positive net interchange is a net energy flow out of the CONTROL AREA.

F_A = Actual frequency (Hz) X the actual average frequency in the INTERCONNECTION for the survey period.

F_S =

Scheduled frequency (Hz)
X the scheduled average frequency in the Interconnection for the survey period.

β = Frequency bias setting (MW/0.1 Hz) X the bias value used by the CONTROL AREA.

10 = A constant to convert the frequency bias setting to MW/Hz.

The following apply to the AIE equation for the Western INTERCONNECTION:

s = 1 if T_d is positive and the CONTROL AREA'S accumulation of inadvertent interchange is positive, or if T_d is negative and the CONTROL AREA'S inadvertent interchange is negative. s = 0 for all other conditions.

β_t =

Time error bias (MW/0.1 Second)
X
the bias value used by the CONTROL AREA to correct for time error. It is has the same sign and value as the frequency bias, β.

T_d = Time error (seconds). 1 second maximum.

C. Survey Procedures

1. **Issuance of Survey**. Surveys will be conducted for periods selected by the chairman or vice chairman of the Resources Subcommittee or designee, on the chairman's or vice chairman's own motion, in response to specific requests from members of the Subcommittee, or when a time error of a magnitude, specified by the Subcommittee, occurs.

1.1. As soon as possible after the survey period is chosen by the chairman, the chairman shall notify the appropriate Subcommittee members by letter of the survey date and hour, average actual frequency during the survey period, and the date for return of survey data.

1.2. Each Subcommittee member shall notify each reporting CONTROL AREA within the Region in writing that a survey is being requested and the average actual frequency during the survey period. The Subcommittee member shall provide for each CONTROL AREA a copy of survey form "NERC Area Interchange Error Survey."

1.3. Each reporting CONTROL AREA shall return one completed copy of the appropriate table to its Subcommittee member. Each Subcommittee member shall review the CONTROL AREA response and send the individual appropriate table results to the NERC staff.

1.4. The NERC staff shall combine the CONTROL AREA data into one report and send one copy to each Subcommittee member.

1.5. Each Subcommittee member shall be responsible for reproducing and distributing the summary report within their Region.

2. **Instructions for AIE Survey for Eastern and ERCOT INTERCONNECTIONS – AIE Form 1**

The line-by-line instructions for the survey form follow:

Line 1: Enter the date and period of the survey (this information is provided by the Resources Subcommittee member's survey request) and the name of the CONTROL AREA.

Line 2: Enter the name of all CONTROL AREAS with which interchange occurred at the time of the survey. Use additional forms if necessary.

Line 3: Enter the mutually agreed upon actual interchange that occurred with each utility for the time of survey; total the entries and place the result in the NET TOTAL column.

Line 4: Enter the mutually agreed upon scheduled interchange with each utility for the time of the survey; total the entries and place the result in the NET TOTAL column. Sign convention for net power into the CONTROL AREA is negative (–), and net power out of the CONTROL AREA is positive (+). Do not include scheduled inadvertent payback on this line.

Line 5: Enter all mutually agreed upon scheduled inadvertent payback with each utility for the time of the survey; total the entries and place the result in the NET TOTAL column. These entries reflect only the portion of the total scheduled interchange with each utility that was used for inadvertent payback. Line 4 + Line 5 = Scheduled Net Interchange, NI_S.

Line 6: Enter the inadvertent interchange (Line 3 – Line 4 – Line 5) occurring with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column.

Line 7: The computed interconnected system frequency error is the value furnished in the survey request letter. Enter the given value here. The given value was computed by taking the difference between the average frequency and the scheduled frequency for the hour being surveyed.

Line 8: Enter the CONTROL AREA'S bias setting. If using a variable bias, enter the integrated bias for the hour.

Line 9: Enter the CONTROL AREA bias obligation. Line 9 = Line 7 x Line 8 x 10.0.

Line 10: Enter all unilateral inadvertent payback that is *not* scheduled with any utility at the time of survey, as in accordance with NERC Operating Guide I.F. (Systems Control – Inadvertent Interchange Management).

Line 11: Enter the adjusted Area Interchange Error. Line 11 = Line 6 Net Total – Line 9 – Line 10.

Line 12: Enter the average ACE (with correct sign) for each of the six ten-minute periods of the hour. (This is the same as the values reported in the CPC survey, except that here it includes the sign.)

Remarks: Please attach a separate sheet with any comments regarding the survey and unusual conditions that may have caused your regulating error.

3. Instructions for AIE Survey for Western INTERCONNECTION – AIE Form 2

The line-by-line instructions for the survey form follow:

Line 1: Enter the date and time of the survey (this information is provided by the Resources Subcommittee member's survey request), and the name of the CONTROL AREA.

Line 2: Enter the name of all utilities with which interchange occurred at the time of the survey. Use additional forms if necessary.

Line 3: Enter the mutually agreed upon actual interchange that occurred with each utility at the time of survey; total the entries and place the result in the NET TOTAL column.

Line 4: Enter the scheduled interchange with each utility at the time of the survey; total the entries and place the NET result in the NET TOTAL column. Sign convention for net power into the CONTROL AREA is negative (–), and net power out of the CONTROL AREA is positive (+). Do not include scheduled inadvertent payback on this line.

Line 5: Enter all mutually agreed upon scheduled inadvertent payback with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column. These entries reflect only the portion of the total scheduled interchange with each utility that was used for inadvertent payback. Line 4 + Line 5 = Scheduled Net Interchange, NI_S.

Line 6: Enter the inadvertent interchange (Line 3 – Line 4 – Line 5) occurring with each utility at the time of the survey; total the entries and place the result in the NET TOTAL column.

Line 7: The computed interconnected system frequency error is the value furnished in the survey request letter. Enter the given value here. The given value was computed by taking the difference between the average frequency and the scheduled frequency for the hour being surveyed.

Line 7a: The computed interconnected time error is the value furnished in the survey request letter. Enter the value here.

Line 8: Enter the CONTROL AREA'S bias setting. If using a variable bias, enter the integrated bias for the hour.

Line 9: Enter the CONTROL AREA bias obligation to correct frequency. Line 9 = Line 7 x Line 8 x 10.0.

Line 9a: Enter the control bias obligation to correct time error. Line 9a = Line 7a x Line 8 x 0.1.

Line 10: Enter all unilateral inadvertent payback that is *not* scheduled with any utility at the time of survey, as in accordance with NERC Operating Guide I.F. (Systems Control X Inadvertent Interchange Management).

Line 11: Enter the Area Interchange Error. Line 11 = Line 6 Net Total – Line 9 – Line 9a – Line 10.

Line 12: Enter the average ACE (with correct sign) for each of the six 10-minute periods of the hour. (This is the same as the values reported in the CPC survey, except that here it includes the sign.)

Remarks: Please attach a separate sheet with any comments regarding the survey and unusual conditions that may have caused your regulating error.

D. Survey Review

1. **Survey Analysis**. Each NERC Resources Subcommittee member shall cross check all input data and analyze the ACE survey results for the CONTROL AREAS within the Region for uniformity, completeness, and compliance to the instructions.

2. **Survey Review**. The NERC Resources Subcommittee may request comments from Regions or CONTROL AREAS relating the causes of excessive ACE and AIE within a CONTROL AREA.

North American Electric Reliability Council
Area Interchange Error Survey
Eastern and ERCOT Interconnections

Form AIE 1

1. Date:	Hr. Ending (CST/CDT):	Control Area:
		Region:

INTERCHANGE DETAILS (All values in MWh)

2: Control Area or Interconnection											Total
3: Actual Interchange											
4: Scheduled Interchange											
5: Scheduled Inadvertent Payback											
6. Inadvertent Interchange											

AREA INTERCHANGE CALCULATION

7. Computed Frequency Deviation		Hz
8. Frequency Bias Setting	–	MW/0.1 Hz (negative value)
9. Bias Obligation		MWh Line 7 x Line 8 x 10.0
10. Unilateral Inadvertent Payback		MWh
11. Adjusted Area Interchange Error		MWh Line 6 Total – Line 9 – Line 10

	1	2	3	4	5	6	Total	Avg
12. Integrated ACE for the 6 consecutive Periods of the survey hour	:00-:10	:10-:20	:20-:30	:30-:40	:40-:50	:50-:60		Total/6

Notes:

List remarks on separate sheet of paper, including conditions causing regulating errors. Net power delivered *out* of a CONTROL AREA (over-generation) is positive (+). Net power received *into* a CONTROL AREA (under-generation) is negative (–).

North American Electric Reliability Council
Area Interchange Error Survey
Western Interconnection

Form AIE 2

1. Date:	Hr. Ending (PST/PDT):	Control Area:
		Region:

INTERCHANGE DETAILS (All values in MWh)

2. Control Area or Interconnection											Total
3. Actual Interchange											
4. Scheduled Interchange											
5. Scheduled Inadvertent Payback											
6. Inadvertent Interchange											

AREA INTERCHANGE CALCULATION

7. Computed Frequency Deviation		Hz
7.5. Computed System Time Error		Seconds
8. Frequency Bias Setting	(–)	MW/0.1 Hz (negative value)
9. Frequency Bias Obligation		MWh Line 7 x Line 8 x 10.0
9.5. Time Error Bias Obligation		MWh s(Line 7.5 x Line 8 x 0.3)*
10. Unilateral Inadvertent Payback		MWh
11. Adjusted Area Interchange Error		MWh Line 6 Total – Line 9 – Line 9.5 – Line 10

	1	2	3	4	5	6	Total	Average
12. Integrated ACE for the 6 consecutive Periods of the survey hour	:00-:10	:10-:20	:20-:30	:30-:40	:40-:50	:50-:60		Total/6

Notes:
List remarks on separate sheet of paper, including conditions causing regulating errors.
Net power delivered *out* of a control area (over-generation) is positive (+).
Net power received *into* a control area (under-generation) is negative (–).
*s is defined as 1 or 0 as explained on the following page.

Frequency Response Characteristic Survey Training Document

Training Document Subsections

A. Frequency Response
- **Frequency Response Characteristic**
- **Response to Internal and External Generation/Load Imbalances**
- **Frequency Bias versus Frequency Response Characteristic (FRC)**
- **Effects of a Disturbance on all CONTROL AREAS External to the Contingent CONTROL AREA**
- **Effects of a Disturbance on the Contingent CONTROL AREA**

B. Survey Procedures
C. Survey Review

This document includes the purpose and description of the Frequency Response Characteristic (FRC) Survey, describes the complete survey procedure including specific instructions to complete the survey form and discusses the use of survey results.

A. Frequency Response

[Appendix 1A – The Area Control Error Equation]

Frequency Response Characteristic Surveys are conducted to determine the frequency response characteristic of a control area. Accurate measurement of system response is difficult unless the frequency deviation resulting from a system disturbance is significant. Therefore, surveys are usually requested when significant frequency deviations occur.

Disturbances can cause the frequency to increase from loss of load or decrease from loss of generation. Frequency Response Surveys may be requested for either event.

1. **Frequency Response Characteristic**. For any change in generation/load balance in the INTERCONNECTION, a frequency change occurs. Each CONTROL AREA in the INTERCONNECTION will respond to this frequency change through:

   - A load change that is proportional to the frequency change due to the load's frequency response characteristic,[1] and

   - A generation change that is inverse to the frequency change due to turbine governor action. The net effect of these two actions is the CONTROL AREA'S response to the frequency change, that is, its *frequency response characteristic*. The combined response of all CONTROL AREAS in the INTERCONNECTION will cause the INTERCONNECTION frequency to settle at some value different from the pre-disturbance value. It will not return frequency to the pre-disturbance value because of the turbine governor droop characteristic. Frequency will remain different until the CONTROL AREA with the generation/load imbalance (referred to as the "Acontingent CONTROL AREA") corrects that imbalance, thus returning the INTERCONNECTION frequency to its pre-disturbance value.

2. **Response to Internal and External Generation/Load Imbalances**. Most of a CONTROL AREA'S frequency response will be reflected in a change in its actual net interchange. By

[1]Rotating (motor) and inductive loads are the predominating factor. Resistive loads do not change with changing frequency.

monitoring the frequency error (the difference between actual and scheduled frequency) and the difference between actual and scheduled interchange and by using its response to frequency deviation, a CONTROL AREA'S automatic generation control (AGC) can determine whether the imbalance in load and generation is internal or external to its system. If internal, the CONTROL AREA'S AGC should correct the imbalance. If external, the CONTROL AREA'S AGC should allow its generator governors to continue responding through its frequency bias contribution until the contingent CONTROL AREA corrects its imbalance, which should return frequency to its pre-disturbance value.

3. **Frequency Bias versus Frequency Response Characteristic (FRC)**. The CONTROL AREA should set its bias to match its FRC. In doing so, the CONTROL AREA'S bias would exactly offset the tie line flow error ($Ni_A - Ni_S$) of the ACE that results from governor action following a frequency deviation on the INTERCONNECTION. The following sections 4 and 5 discuss the effects of bias on control action and explain the importance of setting the bias equal to the CONTROL AREA'S FRC. The discussion explains the control action on all CONTROL AREAS external to the contingent CONTROL AREA (the CONTROL AREA that experienced the sudden generation/load imbalance) and on the contingent CONTROL AREA itself. While this discussion deals with loss of generation, it applies equally to loss of load, or any sudden contingency resulting in a generation/load mismatch. Each CONTROL AREA'S frequency response will vary with each disturbance because generation and load characteristics change continuously. This discussion also assumes that the frequency error from 60 Hz was zero (all ACE values were zero) just prior to the sudden generation/load imbalance.

   For an explanation of the ACE equation, refer to the Area Interchange Error Training Document.

4. **Effects of a Disturbance on all CONTROL AREAS External to the Contingent CONTROL AREA**. When a loss of generation occurs, an INTERCONNECTION frequency error will occur as rotating kinetic energy from the generators is expended[2]. All CONTROL AREAS' generator governors will respond to the frequency error and increase the output of their generators accordingly. This will cause a change in the CONTROL AREAS' actual net interchange. In other words, Ni_A will be greater than Ni_S for all but the contingent CONTROL AREA, and the result will be a positive flow out of the non-contingent CONTROL AREAS.

   If the CONTROL AREAS were using only tie line flow error (i.e., flat tie control ignoring the frequency error), this non-zero ACE would cause their AGC to reduce generation until Ni_A was equal to Ni_S; ACE would then be zero. However, doing this would not help arrest INTERCONNECTION frequency decline because the control areas would not be helping to temporarily replace some of the generation deficiency in the INTERCONNECTION. With the tie-line bias method, the CONTROL AREAS' AGC should allow their governors to continue responding to the frequency deviation until the contingent control area replaces the generation it lost. The resulting tie flow error ($Ni_A - Ni_S$) will be counted as INADVERTENT INTERCHANGE.

   In order for the AGC to allow governor action to continue helping in this way, a frequency bias is added to the tie flow error in the ACE equation. This bias is equal in magnitude and opposite in direction to the governor action and should be exactly equal to each CONTROL AREA'S frequency response characteristic measured in MW/0.1 Hz. Then, when multiplied by the frequency error, the bias should exactly counteract the tie flow error portion of the ACE calculation.

[2]An amount of kinetic energy proportional to the power (generation) lost will be withdrawn from the stored energy in the generator rotors throughout the Interconnection. Thus, Interconnection frequency decreases proportionally.

In other words, bias contribution = $10\beta(f_A B f_S)$. ACE will be zero, and AGC will not readjust generation.

The ACE equation now becomes:

$$ACE = (Ni_A - Ni_S) - 10\beta(f_A - f_S)$$

If the bias setting is greater than the CONTROL AREA'S actual frequency response characteristic, then its AGC will increase generation beyond the governor response, which further helps arrest the frequency decline, but increases INADVERTENT INTERCHANGE. Likewise, if the bias setting is less than the actual FRC, its AGC will reduce generation, reducing the CONTROL AREA'S contribution to arresting the frequency change. In both cases, the control action is unwanted.

5. **Effects of a Disturbance on the Contingent CONTROL AREA**. In the contingent CONTROL AREA where the generation deficiency occurred, most of the replacement power comes from the INTERCONNECTION over its tie lines from the frequency bias contributions of the other CONTROL AREAS in the INTERCONNECTION. A small portion will be made up internally from the contingent CONTROL AREA'S own governor response (bias contribution). In this case, the difference between Ni_A and Ni_S for the contingent CONTROL AREA is much greater than its frequency bias component. Its ACE will be negative, and its AGC will begin to increase generation. *The contingent CONTROL AREA must take appropriate steps to reduce its ACE to zero within ten minutes of the contingency.* (Reference: Operating Criterion II.A.) The energy supplied from the INTERCONNECTION is posted to the contingent CONTROL AREA'S inadvertent balance, and must be paid back.

B. Survey Procedures

Frequency Response Characteristic Surveys will be conducted to compare each CONTROL AREA'S FRC with respect to its bias setting.

1. Issuance of Survey

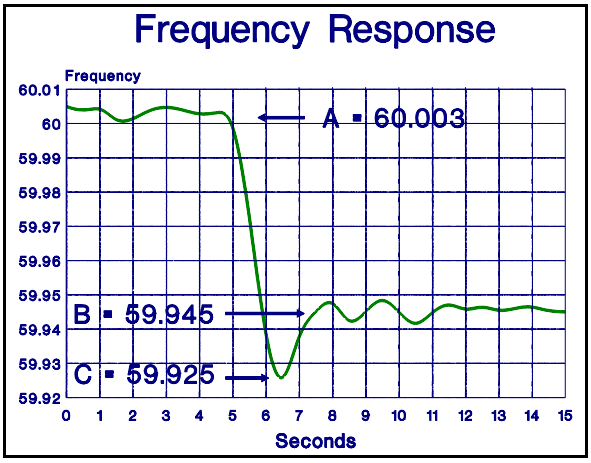
Surveys will be conducted for periods selected by the chairman or vice chairman of the Resources Subcommittee or designee, on the chairman's or vice chairman's own motion, or in response to specific requests from members of the Subcommittee.

- As soon as possible after the survey period is chosen by the chairman, the chairman or vice chairman shall notify each appropriate Subcommittee member by letter of the survey date and time, the frequency points A, B, and C, frequency deviation, and date for the survey to be returned.
- Each Subcommittee member shall notify each reporting CONTROL AREA within the Region by written request. The Subcommittee member shall provide each CONTROL AREA a copy of the survey form "NERC Frequency Response Characteristic Survey."
- Each reporting control area shall return one completed copy of the survey form and a copy of its frequency chart.
- Each Subcommittee member shall review the appropriate control area results and send the copies of survey form results to the NERC staff.
- The NERC staff shall combine the control area data into one report and send one copy to each Subcommittee member.
- Each Subcommittee member shall be responsible for reproducing and distributing the summary report within their Region.

2. Instructions for FRC Survey

The table is the Control Area Frequency Response Characteristic Survey form.

A sample frequency chart is shown in Figure 1 with points A, B, and C labeled. Point A represents the interconnected system frequency immediately before the disturbance. Point B represents the interconnected system frequency at the point immediately after the frequency stabilizes due to governor action but before the contingent control area takes corrective AGC action. Point C represents the interconnected system frequency at its maximum deviation due to the loss of rotating kinetic energy from the turbine generators.



Line-by-line instructions for the survey form follow:

Line 1: Enter the date and time of survey period (this information is provided by the RESOURCES SUBCOMMITTEE member's survey request) and the name of the control area.

Line 2: Enter the net interchange of the control area immediately before the survey period (corresponding to Point A). Sign convention for net power into a CONTROL AREA is negative (–), and net power out of a control area is positive (+).

Line 3: Enter the net interchange of the control area immediately after the survey period (corresponding to Point B). Use the same sign convention as Line 2.

A

Line 4: Enter the change in net interchange of the CONTROL AREA. Line 4 = Line 3 – Line 2. For a disturbance that causes the frequency to decrease, this value should be positive except for the contingent CONTROL AREA, in which case it is negative.

Line 5: If the control area completing the survey suffered the loss, enter the load or generation lost by the control area. Otherwise, leave this line blank. Sign convention for generation loss is negative (–) and for load loss is positive (+).

Line 6: Enter the control area response. This value is (Line 4 – Line 5).

Line 7: Enter the change in interconnected system frequency as specified in the letter of transmittal.

Line 8: Enter the frequency response characteristic of the CONTROL AREA based on the change in interconnected system frequency. This value is:

$$FRC = \frac{Line6}{(Line7)10.0}$$

(The factor of 10.0 is used to change the units to MW/0.1 Hz.) This value approximates the frequency response of the control area for this disturbance.

Line 9: Enter the frequency bias setting of the CONTROL AREA.

Line 10: Enter the CONTROL AREA'S net system load immediately before the disturbance.

Line 11: Enter the CONTROL AREA'S total capacity synchronized to the INTERCONNECTION immediately before the disturbance. Jointly owned units should be reported in their entirety by the CONTROL AREA in which they are located.

Lines 12, 13, and 14:

Enter the frequency values you observed from the frequency chart for Points A, B, and C, respectively.

C. Survey Review

Each NERC RESOURCES SUBCOMMITTEE member shall analyze the survey results of the CONTROL AREAS within their Region. The survey data received on the survey form shall be reviewed for uniformity, completeness, and compliance to the instructions. The NERC Resources Subcommittee will review the total frequency response for the total INTERCONNECTION surveyed to ensure adequate frequency bias exists to maintain the scheduled frequency.

North American Electric Reliability Council
Frequency Response Characteristic Survey

Form FRC 1

1. Date **Hr. Ending** **(CST/CDT):**	**Control Area:**
	Region:

AREA FREQUENCY RESPONSE CALCULATION

2: Actual Net Interchange Immediately Before Disturbance (Point A)*		**MW**
3: Actual Net Interchange Immediately After Disturbance (Point B)*		**MW**
4: Change in Net Interchange		**MW Line 3 – Line 2**
5: Load (+) or Generation (B) Lost Causing the Disturbance		**MW**
6. Control Area Response		**MW Line 4 – Line 5**
7. Change in Interconnection Frequency from Point A to Point B		**Hz (–) for frequency decrease; (+) for frequency increase**
8. Frequency Response Characteristic		**MW/0.1 Hz Line 6 /(Line 7 x 10.0)**

OTHER INFORMATION

9. Frequency Bias Setting				**MW/0.1 Hz**
10. Net System Demand Immediately Before Disturbance (Point A)				**MW**
11. Synchronized Capacity Immediately Before Disturbance (Point A)				**MW**
12.	**From your charts**	**Frequency at Point A**		**Hz**
13.		**Frequency at Point B**		**Hz**
14.		**Frequency at Point C**		**Hz**

Notes:

Net power delivered *out* of a control area (over-generation) is positive (+).
Net power received *into* a control area (under-generation) is negative (–).

*CONTROL AREAS that have a Net Tie Deviation From Schedule Recorder should obtain these values from that device.

Inadvertent Interchange Accounting Training Document

Training Document Subsections

A. Introduction
B. Definitions
C. Interchange Accounting
D. Inadvertent Interchange Energy Accounting Practices
E. Interchange Accounting Practices for Jointly owned Generating Units
F. Interchange Accounting Practices for Regulation Service

A. Introduction

[Appendix 1F – Inadvertent Interchange Energy Accounting Practices]

The purpose of this document is to explain inadvertent interchange (inadvertent) accounting. Included within this document are accounting practices that every control area within the North American Electric Reliability Council shall follow. These practices provide a method for isolating and eliminating the source(s) of accounting errors. They may also be used as an aid in identifying the poor control performance that contributes to inadvertent accumulations.

Additional information concerning inadvertent may be found in the NERC Operating Manual under Operating Policy 1F., Inadvertent Interchange.

Simple accounting errors (value or sign) made while recording actual net interchange or scheduled net interchange become operating problems as soon as they become a part of hourly accounting. This occurs because the system dispatcher may be influenced to bilaterally or unilaterally pay back inadvertent or offset a schedule setter to correct a perceived metering error. Viewed from a total interconnected network (Interconnection) perspective, when inadvertent no longer sums to zero due to accounting errors subsequent unilateral pay backs to correct for the "perceived" inadvertent will cause a generation surplus or deficiency on the interconnection. Ultimately this shows up in the form of a continuously recurring time error.

B. Definitions

Adjacent Control Areas: Any control areas within an Interconnection sharing a common tie line or metering point.

Hourly MWh Metered Values: MWh data accumulated (whether by telemetry, telephone, direct meter readings, etc.) on an hourly basis.

Adjustments For Error: Either meter errors, absence of metering data due to communication failure or missing data for whatever cause. The important point is that such adjustments are made between control areas involved in the same manner and at the same times in opposite directions.

C. Interchange Accounting

1. **Accounting For Interchange.** Accounting for energy between control areas residing within the same Interconnection is both simple and complicated. In theory, and in accordance to NERC Guides, inadvertent interchange is the difference between actual net interchange and scheduled net interchange over a given period, usually an hour. Mathematically it is the time integral of the deviation of a control area's actual net interchange from its scheduled net interchange:

$$NI_I = NI_A - NI_S$$

Where,

NI_I is inadvertent interchange. In accordance with NERC convention, negative values of inadvertent interchange denote a condition of undergeneration and positive values denote overgeneration.

NI_A is actual net interchange. It is the algebraic sum of the hourly integrated energy on a control area's tie lines including pseudo-ties for any jointly owned generating units. Actual net interchange is positive for power leaving the system and negative for power entering.

NI_S is scheduled net interchange. It is defined as the mutually prearranged net energy on a control area□s tie lines including dynamic schedules or fixed schedules for any jointly owned generating units. Scheduled net interchange is positive for power scheduled to be delivered from the system and negative for power scheduled to be received into the system.

2. **Actual Net Interchange Energy Accounting**. Actual net interchange (metered interchange) between two adjacent control areas over a common tie line is accounted for at a specific point in the line. Furthermore, both control areas shall agree on the amount of energy flow through this point, including any pseudo-tie flows for jointly owned generating units that may exist between the two control areas. Therefore, the sum of metered energy accounted by both control areas over this tie line nets to zero. Since this is true for all control areas within the same Interconnection, the algebraic sum of all metered energy within the same Interconnection is also zero.

3. **Scheduled Net Interchange Energy Accounting**. All scheduled net interchange (and schedule changes) shall be agreed upon between the control areas involved prior to implementation in regard to magnitude, rate of change, and common starting time. Dynamic schedules and fixed schedules for jointly owned generating units between control areas should be agreed to on an hour-by-hour basis, and included as scheduled interchange. Since every interchange schedule is agreed to by all delivering and receiving control areas within an Interconnection, the algebraic sum of all scheduled net interchange is also zero.

4. **Inadvertent Interchange Energy Accounting**. As stated previously, inadvertent interchange is the difference between actual net interchange and scheduled net interchange over a given period. Since the algebraic sum of all actual net interchange and the algebraic sum of all scheduled net interchange for any given period is zero within an Interconnection, the sum of all inadvertent interchange is also zero.

D. Inadvertent Interchange Energy Accounting Practices

The practices set forth in this section outline the methods and procedures required to reconcile energy accounting and inadvertent interchange balances.

In order for a control area to properly monitor and account for inadvertent interchange, it shall adhere to the NERC Operating Policies.

1. Accounting Procedures

1.1. On-Peak and Off-Peak Accounting Periods. Each control area is obligated to maintain its inadvertent interchange accounting within two periods, namely, on-peak and off-peak (refer to Appendix A).

1.2. Schedules. All hourly schedules and schedule changes shall be agreed upon between the control areas involved prior to implementation in regard to magnitude, rate of change, and common starting time.

1.3. Dynamic Schedules. Dynamic schedules integrated on an hourly basis shall be agreed upon by the control areas involved subsequent to the hour, but in such a manner as not to impact inadvertent accounts. This is accomplished by ensuring that the hourly actual and scheduled interchange quantities agree between all delivering and receiving parties.

1.4. Daily Accounting. Each control area shall agree with adjacent control areas on the actual net interchange (MWh) and scheduled net interchange (MWh) at least once each day for on-peak and off-peak periods.

1.5. Monthly Accounting. Having agreed to the on-peak and off-peak period accumulations on a daily basis, adjacent control areas shall verify that the accumulated values for the month balance.

1.6. Adjustments for Error. Adjustments shall be made at least once each month to correct for differences between hourly MWh meter totals and the totals derived from register readings at the tie line meters.

1.6.1 Differences. Adjacent control areas shall agree upon the difference determined above and assign this correction to the proper on-peak and off-peak period at the same times and in equal quantities in the opposite directions.

1.6.2 Adjustments. Any adjustments necessary due to known metering errors, franchised territories, transmission losses or other special circumstances shall be made in the same manner.

2. Accounting Periods For Control Areas *Not* Using Daylight Savings Time

Some control areas (and states) do not recognize Daylight Saving Time. Where this is the case, inadvertent interchange accounting periods must be shifted in order to remain coordinated with the rest of the control areas that do recognize Daylight Saving Time.

During the shift to Daylight Saving Time, control areas not recognizing Daylight Saving Time should change their accounting periods as follows:

2.1. For the Eastern and ERCOT Interconnections

2.1.1. Atlantic Time Zone. If the control area is in the Atlantic Time Zone, then the on-peak hours change from Hour Ending (HE) 0900–HE 2400 AST Monday through Saturday to HE 0800–HE 2300 AST Monday through Saturday. Similarly, the off-peak hours change from HE 0100–HE 0800 AST Monday through Saturday to HE 2400–HE 0700 AST Monday through Saturday.

2.1.2 Eastern Time Zone. If the control area is in the Eastern Time Zone, then the on-peak hours change from Hour Ending (HE) 0800–HE 2300 EST Monday through Saturday to HE 0700–HE 2200 EST Monday through Saturday. Similarly, the off-peak hours change from HE 2400–HE 0700 EST Monday through Saturday to HE 2300–HE 0600 EST Monday through Saturday.

2.1.3 Central Time Zone. If the control area is in the Central Time Zone, then the on-peak hours change from HE 0700–HE 2200 CST Monday through Saturday to HE 0600–HE 2100 CST Monday through Saturday. Similarly, the off-peak hours change from HE 2300–HE 0600 CST Monday through Saturday to HE 2200–HE 0500 CST Monday through Saturday.

2.2. For the Western Interconnection

2.1.1. Central Time Zone. If the control area is in the Central Time Zone, then the on-peak hours change from HE 0900–HE 2400 CST Monday through Saturday to HE 0800–HE 2300 CST Monday through Saturday. Similarly, the off-peak hours change from HE 0100–HE 0800 CST Monday through Saturday to HE 2400–HE 0700 CST Monday through Saturday.

2.1.2. Mountain Time Zone. If the control area is in the Mountain Time Zone, then the on-peak hours change from HE 0800–HE 2300 MST Monday through Saturday to HE 0700–HE 2200 MST Monday through Saturday. Similarly, the off-peak hours change from HE 2400–HE 0700 MST Monday through Saturday to HE 2300–HE 0600 MST Monday through Saturday.

2.1.3. Pacific Time Zone. If the control area is in the Pacific Time Zone, then the on-peak hours change from HE 0700–HE 2200 PST Monday through Saturday to HE 0600–HE 2100 PST Monday through Saturday. Similarly, the off-peak hours change from HE 2300–HE 0600 PST Monday through Saturday to HE 2200–HE 0500 PST Monday through Saturday.

3. Accounting for Inadvertent Interchange over DC Tie Lines between Separately Synchronous Interconnections

For the purpose of NERC inadvertent interchange accounting, there shall be no contribution to a control area's inadvertent accumulation due to a dc tie connecting adjacent control areas operating in separate Interconnections.

4. Summary Of Accounting Rules

4.1. Summation of scheduled net interchange. The summation of all scheduled net interchange within an Interconnection shall total zero for any period of time.

4.2. Summation of actual net interchange. The summation of all actual net interchange within an Interconnection shall total zero for any period of time.

4.3. Summation of inadvertent interchange for Interconnection. The summation of all inadvertent interchange within an Interconnection shall total zero for any period of time.

5. Accounting Examples

Daily, total all actual net interchange accumulated during the on-peak and off-peak periods. Do the same with the scheduled net interchange. By period, subtract the totaled scheduled net interchange from the totaled actual net interchange. This will yield on-peak and off-peak inadvertent accumulations for the day. The addition of these two accumulations is the control area=s inadvertent interchange accumulation for the day. All control areas are required to keep an accurate, continuous record of their current balances of on-peak, off-peak, and (net) inadvertent for the day, month, and accumulative to date.

As an example, the Western Interconnection's month-end inadvertent interchange report for February 1995 is included on the following page. Every control area in the Interconnection is included. The sum of each period's inadvertent totals to zero.

An example of an individual control area's month-end data submittal to its Performance Subcommittee representative is also included.

E. Interchange Accounting Practices for Jointly Owned Generating Units

[Appendix 1A – The Area Control Error Equation, Section B – Jointly Owned Units]

1. Jointly Owned Generating Units. It is assumed that every jointly owned generating unit resides within a host control area. It is also assumed that every owner will treat its share of the unit as generation within its own control area. Recipients may account for their share of unit output by one of three methods. All participants in a jointly owned generating unit must agree with the host control area on which of these methods is to be used:

1.1 Scheduled interchange. The host control area and the recipient control area agree on a pre-determined, fixed schedule. Generally, these schedules are manually altered to adjust for unplanned operating conditions at the unit, e.g., if the unit unexpectedly trips out of service.

1.2 **Dynamically scheduled interchange.** The host control area and recipient control area share an electronic signal indicating the real-time power transfer from the unit to the recipient. The host control area and recipient control areas see this transfer as a continually changing schedule between the two control areas. It is recommended that after-the-fact adjustments for month-end accumulators or erroneous signals be corrected in future operating periods and not be back-corrected.

1.3 **As a pseudo-tie.** The host control area and the recipient control area share an electronic signal indicating the real-time energy transfer from the unit to the recipient. The host control area and the recipient control area see this transfer as continually changing metered interchange between the two control areas. It is recommended that after-the-fact adjustments for month-end accumulators or erroneous signals be corrected in future operating periods and not be back-corrected.

F. Interchange Accounting Practices for Regulation Service

If a control area provides regulation service for another control area, it generally will occur in one of two ways:

1. **Supplemental Regulation.** The control area providing supplemental regulation service will receive a signal representing all or a portion of the other control area's ACE. Control areas participating in supplemental regulation are not required to make any changes to their accounting systems. Supplemental regulation can be implemented as a dynamic schedule or a pseudo-tie. Both control areas need to use the same method.

2. **Overlap Regulation.** The control area providing overlap regulation service will include all of the other control area's tie lines and schedules in its (the providing control area's) AGC equation. Entities participating in overlap regulation are required to notify the control area providing the regulation of all interchange schedules with other control areas before they are implemented. This is necessary to maintain the integrity of central coordinated control. Ultimate responsibility for energy accounting lies solely with the control area providing the overlap regulation service.

	ON-PEAK			OFF-PEAK			TOTAL		
	Previous Accum.	Net For Month	Carried Forward	Previous Accum.	Net For Month	Carried Forward	Previous Accum.	Net For Month	Carried Forward
B. C. Hydro & Power Authority	726	(1,191)	(465)	582	(1,114)	(532)	1,308	(2,305)	(997)
Bonneville Power Administration	(645)	926	281	1,504	(1,064)	440	859	(138)	721
Chelan County P.U.D. #1	72	(132)	(60)	11	(70)	(59)	83	(202)	(119)
Douglas County P.U.D. #1	3	2	5	0	6	6	3	8	11
Grant County P.U.D. #2	(4)	(54)	(58)	(25)	(29)	(54)	(29)	(83)	(112)
Idaho Power Company	691	(842)	(151)	(73)	87	14	618	(755)	(137)
Montana Power Company	6	43	49	(9)	7	(2)	(3)	50	47
Pacificorp – East	(221)	1,000	779	181	(64)	117	(40)	936	896
Pacificorp – West	(52)	(279)	(331)	(66)	50	(16)	(118)	(229)	(347)
Portland General Electric Company	(109)	108	(1)	35	(193)	(158)	(74)	(85)	(159)
Puget Sound Power & Light Company	45	(29)	16	(9)	(66)	(75)	36	(95)	(59)
Seattle City Light	8	(6)	2	(7)	11	4	1	5	6
Sierra Pacific Power Company	4	(13)	(9)	(72)	202	130	(68)	189	121
Tacoma City Light	(3)	(6)	(9)	(60)	(8)	(68)	(63)	(14)	(77)
TransAlta Utilities Corporation	(33)	(6)	(39)	(571)	(52)	(623)	(604)	(58)	(662)
Washington Water Power Company	1	69	70	(7)	21	14	(6)	90	84
Los Angeles Department of Water & Power	219	117	336	(419)	538	119	(200)	655	455
Pacific Gas & Electric Company	(2,374)	(621)	(2,995)	(1,974)	599	(1,375)	(4,348)	(22)	(4,370)
San Diego Gas & Electric Company	382	(369)	13	(96)	99	3	286	(270)	16
City of Pasadena	(539)	(26)	(565)	490	31	521	(49)	5	(44)
Nevada Power Company	562	(1,797)	(1,235)	161	(832)	(671)	723	(2,629)	(1,906)
Southern California Edison Company	3,084	1,420	4,504	1,670	(1,431)	239	4,754	(11)	4,743
Comision Federal de Electricidad	27	(5)	22	(3)	18	15	24	13	37
Arizona Public Service Company	(625)	891	266	(227)	855	628	(852)	1,746	894
El Paso Electric Company	27	5	32	(21)	42	21	6	47	53
Imperial Irrigation District	(287)	1,354	1,067	1,021	814	1,835	734	2,168	2,902
Public Service Company of New Mexico	108	68	176	255	236	491	363	304	667
Salt River Project	158	80	238	246	146	392	404	226	630
Tucson Electric Power Company	76	(73)	3	(55)	17	(38)	21	(56)	(35)
Western Area Power Administration – LC	(41)	111	70	(41)	114	73	(82)	225	143
Public Service Company of Colorado	659	1,282	1,941	(263)	257	(6)	396	1,539	1,935

Western Area Power Administration - UM	942	240	1,182	1,516	87	1,603	2,458	327	2,785
Western Area Power Administration - CM	(2,867)	(2,267)	(5,134)	(3,674)	686	(2,988)	(6,541)	(1,581)	(8,122)
TOTAL	0	0	0	0	0	0	0	0	0

PACIFICORP – EAST
INADVERTENT INTERCHANGE ACCOUNTING SUMMARY
FEBRUARY 1995 – CENTRAL STANDARD TIME

	ON-PEAK INTERCHANGE			OFF-PEAK INTERCHANGE			TOTAL INTERCHANGE		
ADJACENT CONTROL AREA	Actual MWh	Scheduled MWh	Inadvertent MWh	Actual MWh	Scheduled MWh	Inadvertent MWh	Actual MWh	Scheduled MWh	Inadvertent MWh
Arizona Public Service Company	62,877	116,239	(53,362)	31,912	40,130	(8,218)	94,789	156,369	(61,580)
Idaho Power Company	138,439	(70,517)	208,956	163,561	3,796	159,765	302,000	(66,721)	368,721
Los Angeles Dept. of Water and Power	89,226	66,248	22,978	38,487	19,511	18,976	127,713	85,759	41,954
Montana Power Company	18,640	7,582	11,058	53,576	36,771	16,805	72,216	44,353	27,863
Nevada Power Company	64,464	32,490	31,974	49,430	24,660	24,770	113,894	57,150	56,744
PacifiCorp – West	(233,626)	(22,214)	(211,412)	(159,770)	36,224	(195,994)	(393,396)	14,010	(407,406)
Sierra Pacific Power Company	23,482	53,827	(30,345)	17,497	37,582	(20,085)	40,979	91,409	(50,430)
Western Area Power Admin. -- CM	(63,300)	(84,453)	21,153	(28,895)	(32,812)	3,917	(92,195)	(117,265)	25,070
TOTAL	100,202	99,202	1,000	165,798	165,862	(64)	266,000	265,064	936

		ON-PEAK				OFF-PEAK				NET	
Previous Accumulation		-221				181				-40	
Net for Month		1,000				(64)				936	
Carried Forward		779				117				896	

DATA

Balancing Authorities

Acronym	Balancing Authority Name	Region
AEC	Alabama Electric Cooperative, Inc.	SERC
AESO	Alberta Electric System Operator	WECC-NWPP
YAD	Alcoa Power Generating, Inc. - Yadkin Division	SERC
ALTE	Alliant Energy - CA - ALTE	MRO
ALTW	Alliant Energy - CA - ALTW	MRO
AMRN	Ameren Transmission	SERC
MPS	Aquila Networks - MPS	SPP
WPEK	Aquila Networks - WPK	SPP
AZPS	Arizona Public Service Company	WECC-AZNMSNV
AECI	Associated Electric Cooperative, Inc.	SERC
AVA	Avista Corp.	WECC-NWPP
BCA	Batesville Control Area	SERC
BREC	Big Rivers Electric Corp.	SERC
KACY	Board of Public Utilities	SPP
BPAT	Bonneville Power Administration	WECC-NWPP
BCHA	British Columbia Transmission Corporation	WECC-NWPP
CISO	California Independent System Operator	WECC-CAMX
CNWY	CECD, LLC - Conway	SERC
WMUC	CECD, LLC - West Memphis	SERC
CSWS	Central and Southwest	SPP
CILC	Central Illinois Light Co	SERC
CIN	Cinergy Corporation	RFC
HST	City of Homestead	FRCC
INDN	City of Independence Missouri	SPP
LAFA	City of Lafayette	SPP
TAL	City of Tallahassee	FRCC
CWLP	City Water Light & Power	RFC
CLEC	Cleco Corporation, Inc.	SPP
CWLD	Columbia Water & Light	SERC
CFE	Comision Federal de Electricidad	WECC-CAMX
DPC	Dairyland Power Cooperative	MRO
DEAA	DECA, LLC - Arlington Valley	WECC-AZNMSNV
DENL	DECA, LLC - North Little Rock	SERC
DERS	DECA, LLC - Ruston	SERC
DEVI	DECA, LLC - Vermillion	RFC
DUK	Duke Power Company	SERC
EKPC	East Kentucky Power Cooperative, Inc.	SERC
EPE	El Paso Electric Company	WECC-AZNMSNV
EEI	Electric Energy, Inc.	SERC
EDE	Empire District Electric Co., The	SPP
EES	Entergy Services, Inc.	SERC
ERCO	ERCOT ISO	ERCOT
FE	First Energy Corp.	RFC
FMPP	Florida Municipal Power Pool	FRCC
FPL	Florida Power & Light	FRCC
FPC	Florida Power Corporation	FRCC
GVL	Gainesville Regional Utilities	FRCC
GRMA	Gila River Maricopa Arizona	WECC-AZNMSNV
GRDA	Grand River Dam Authority	SPP
GRE	Great River Energy	MRO
HGMA	Harquahala L.L.C.	WECC-AZNMSNV
HE	Hoosier Energy	RFC

Balancing Authorities

Acronym	Balancing Authority Name	Region
HQT	Hydro-Quebec, TransEnergie	NPCC
IPCO	Idaho Power Company	WECC-NWPP
IP	Illinois Power Co.	SERC
IID	Imperial Irrigation District	WECC-AZNMSNV
IESO	Independent Electricity System Operator	NPCC
IPL	Indianapolis Power & Light Company	RFC
ISNE	ISO New England Inc.	NPCC
JEA	JEA	FRCC
KCPL	Kansas City Power & Light, Co	SPP
LGEE	LG&E Energy Transmission Services	RFC
LES	Lincoln Electric System	MRO
LDWP	Los Angeles Department of Water and Power	WECC-CAMX
LEPA	Louisiana Energy & Power Authority	SPP
LAGN	Louisiana Generating, LLC	SERC
MGE	Madison Gas and Electric Company	MRO
MAR	Maritime Area	NPCC
MHEB	MHEB, Transmission Services	MRO
MECS	Michigan Electric Coordinated Systems	RFC
MEC	MidAmerican Energy Company	MRO
MP	Minnesota Power, Inc.	MRO
MPW	Muscatine Power and Water	MRO
NPPD	Nebraska Public Power District	MRO
NEVP	Nevada Power Company	WECC-AZNMSNV
NYIS	New York Independent System Operator	NPCC
NIPS	Northern Indiana Public Service Company	RFC
NSP	Northern States Power Company	MRO
NWMT	NorthWestern Energy	WECC-NWPP
OVEC	Ohio Valley Electric Corporation	RFC
OKGE	Oklahoma Gas and Electric	SPP
OPPD	Omaha Public Power District	MRO
OTP	Otter Tail Power Company	MRO
PACE	PacifiCorp-East	WECC-NWPP
PACW	PacifiCorp-West	WECC-NWPP
PJM	PJM Interconnection	RFC
PGE	Portland General Electric Company	WECC-NWPP
CPLE	Progress Energy Carolinas - EAST	SERC
CPLW	Progress Energy Carolinas - WEST	SERC
PSCO	Public Service Company of Colorado	WECC-RMPA
PNM	Public Service Company of New Mexico	WECC-AZNMSNV
CHPD	PUD No. 1 of Chelan County	WECC-NWPP
DOPD	PUD No. 1 of Douglas County	WECC-NWPP
GCPD	PUD No. 2 of Grant County	WECC-NWPP
PSEI	Puget Sound Energy	WECC-NWPP
RC	Reedy Creek Improvement District	FRCC
SMUD	Sacramento Municipal Utility District	WECC-CAMX
SRP	Salt River Project	WECC-AZNMSNV
SPC	SaskPower Grid Control Centre	MRO
SCL	Seattle Department of Lighting	WECC-NWPP
SEC	Seminole Electric Cooperative	FRCC
SPPC	Sierra Pacific Power Company	WECC-NWPP
SCEG	South Carolina Electric & Gas Company	SERC
SC	South Carolina Public Service Authority (Santee Cooper)	SERC
SMEE	South Mississippi Electric Power Association	SERC

Balancing Authorities

Acronym	Balancing Authority Name	Region
SEHA	Southeastern Power Administration - Hartwell	SERC
SERU	Southeastern Power Administration - Russell	SERC
SETH	Southeastern Power Administration - Thurmond	SERC
SOCO	Southern Company Services, Inc.	SERC
SIPC	Southern Illinois Power Cooperative	SERC
SIGE	Southern Indiana Gas & Electric Co.	RFC
SMP	Southern Minnesota Municipal Power Agency	MRO
SPA	Southwestern Power Administration	SPP
SPS	Southwestern Public Service Company	SPP
SECI	Sunflower Electric Power Corporation	SPP
TPWR	Tacoma Power	WECC-NWPP
TEC	Tampa Electric Company	FRCC
TVA	Tennessee Valley Authority	SERC
TEPC	Tucson Electric Power Company	WECC-AZNMSNV
TID	Turlock Irrigation District	WECC-CAMX
PUPP	Union Power Partners, LLC	SERC
UPPC	Upper Peninsula Power Co.	MRO
NSB	Utilities Commission, City of New Smyrna Beach	FRCC
WACM	Western Area Power Administration - Colorado-Missouri	WECC-RMPA
WALC	Western Area Power Administration - Lower Colorado	WECC-AZNMSNV
WAUE	Western Area Power Administration - Upper Great Plains East	MRO
WAUW	Western Area Power Administration - Upper Great Plains West	WECC-NWPP
WFEC	Western Farmers Electric Cooperative	SPP
WR	Western Resources dba Westar Energy	SPP
WEC	Wisconsin Energy Corporation	RFC
WPS	Wisconsin Public Service Corporation	MRO

Balancing Authorities by Region

Region	*Balancing Authority*	*Acronym*
ERCOT	**Number of Balancing Authorities: 1**	
	ERCOT ISO	ERCO
FRCC	**Number of Balancing Authorities: 11**	
	City of Homestead	HST
	City of Tallahassee	TAL
	Florida Municipal Power Pool	FMPP
	Florida Power & Light	FPL
	Florida Power Corporation	FPC
	Gainesville Regional Utilities	GVL
	JEA	JEA
	Reedy Creek Improvement District	RC
	Seminole Electric Cooperative	SEC
	Tampa Electric Company	TEC
	Utilities Commission, City of New Smyrna Beach	NSB
MRO	**Number of Balancing Authorities: 19**	
	Alliant Energy - CA - ALTE	ALTE
	Alliant Energy - CA - ALTW	ALTW
	Dairyland Power Cooperative	DPC
	Great River Energy	GRE
	Lincoln Electric System	LES
	Madison Gas and Electric Company	MGE
	MHEB, Transmission Services	MHEB
	MidAmerican Energy Company	MEC
	Minnesota Power, Inc.	MP
	Muscatine Power and Water	MPW
	Nebraska Public Power District	NPPD
	Northern States Power Company	NSP
	Omaha Public Power District	OPPD
	Otter Tail Power Company	OTP
	SaskPower Grid Control Centre	SPC
	Southern Minnesota Municipal Power Agency	SMP
	Upper Peninsula Power Co.	UPPC
	Western Area Power Administration - Upper Great Plains East	WAUE
	Wisconsin Public Service Corporation	WPS
NPCC	**Number of Balancing Authorities: 5**	
	Hydro-Quebec, TransEnergie	HQT
	Independent Electricity System Operator	IESO
	ISO New England Inc.	ISNE
	Maritime Area	MAR
	New York Independent System Operator	NYIS

Balancing Authorities by Region

Region	*Balancing Authority*	*Acronym*
RFC	**Number of Balancing Authorities: 13**	
	Cinergy Corporation	CIN
	City Water Light & Power	CWLP
	DECA, LLC - Vermillion	DEVI
	First Energy Corp.	FE
	Hoosier Energy	HE
	Indianapolis Power & Light Company	IPL
	LG&E Energy Transmission Services	LGEE
	Michigan Electric Coordinated Systems	MECS
	Northern Indiana Public Service Company	NIPS
	Ohio Valley Electric Corporation	OVEC
	PJM Interconnection	PJM
	Southern Indiana Gas & Electric Co.	SIGE
	Wisconsin Energy Corporation	WEC
SERC	**Number of Balancing Authorities: 30**	
	Alabama Electric Cooperative, Inc.	AEC
	Associated Electric Cooperative, Inc.	AECI
	Ameren Transmission	AMRN
	Batesville Control Area	BCA
	Big Rivers Electric Corp.	BREC
	Central Illinois Light Co	CILC
	CECD, LLC - Conway	CNWY
	Progress Energy Carolinas - EAST	CPLE
	Progress Energy Carolinas - WEST	CPLW
	Columbia Water & Light	CWLD
	DECA, LLC - North Little Rock	DENL
	DECA, LLC - Ruston	DERS
	Duke Power Company	DUK
	Electric Energy, Inc.	EEI
	Entergy Services, Inc.	EES
	East Kentucky Power Cooperative, Inc.	EKPC
	Illinois Power Co.	IP
	Louisiana Generating, LLC	LAGN
	Union Power Partners, LLC	PUPP
	South Carolina Public Service Authority (Santee Cooper)	SC
	South Carolina Electric & Gas Company	SCEG
	Southeastern Power Administration - Hartwell	SEHA
	Southeastern Power Administration - Russell	SERU
	Southeastern Power Administration - Thurmond	SETH
	Southern Illinois Power Cooperative	SIPC
	South Mississippi Electric Power Association	SMEE
	Southern Company Services, Inc.	SOCO
	Tennessee Valley Authority	TVA
	CECD, LLC - West Memphis	WMUC
	Alcoa Power Generating, Inc. - Yadkin Division	YAD

Balancing Authorities by Region

Region	*Balancing Authority*	*Acronym*
SPP	**Number of Balancing Authorities: 17**	
	Aquila Networks - MPS	MPS
	Aquila Networks - WPK	WPEK
	Board of Public Utilities	KACY
	Central and Southwest	CSWS
	City of Independence Missouri	INDN
	City of Lafayette	LAFA
	Cleco Corporation, Inc.	CLEC
	Empire District Electric Co., The	EDE
	Grand River Dam Authority	GRDA
	Kansas City Power & Light, Co	KCPL
	Louisiana Energy & Power Authority	LEPA
	Oklahoma Gas and Electric	OKGE
	Southwestern Power Administration	SPA
	Southwestern Public Service Company	SPS
	Sunflower Electric Power Corporation	SECI
	Western Farmers Electric Cooperative	WFEC
	Western Resources dba Westar Energy	WR
WECC-AZNMSNV	**Number of Balancing Authorities: 11**	
	Arizona Public Service Company	AZPS
	DECA, LLC - Arlington Valley	DEAA
	El Paso Electric Company	EPE
	Gila River Maricopa Arizona	GRMA
	Harquahala L.L.C.	HGMA
	Imperial Irrigation District	IID
	Nevada Power Company	NEVP
	Public Service Company of New Mexico	PNM
	Salt River Project	SRP
	Tucson Electric Power Company	TEPC
	Western Area Power Administration - Lower Colorado	WALC
WECC-CAMX	**Number of Balancing Authorities: 5**	
	California Independent System Operator	CISO
	Comision Federal de Electricidad	CFE
	Los Angeles Department of Water and Power	LDWP
	Sacramento Municipal Utility District	SMUD
	Turlock Irrigation District	TID

Balancing Authorities by Region

Region	*Balancing Authority*	*Acronym*
WECC-NWPP	**Number of Balancing Authorities: 17**	
	Alberta Electric System Operator	AESO
	Avista Corp.	AVA
	Bonneville Power Administration	BPAT
	British Columbia Transmission Corporation	BCHA
	Idaho Power Company	IPCO
	NorthWestern Energy	NWMT
	PacifiCorp-East	PACE
	PacifiCorp-West	PACW
	Portland General Electric Company	PGE
	PUD No. 1 of Chelan County	CHPD
	PUD No. 1 of Douglas County	DOPD
	PUD No. 2 of Grant County	GCPD
	Puget Sound Energy	PSEI
	Seattle Department of Lighting	SCL
	Sierra Pacific Power Company	SPPC
	Tacoma Power	TPWR
	Western Area Power Administration - Upper Great Plains West	WAUW
WECC-RMPA	**Number of Balancing Authorities: 2**	
	Public Service Company of Colorado	PSCO
	Western Area Power Administration - Colorado-Missouri	WACM

Total Number of Balancing Authorities: 131

NERC

Regional Entities and Balancing Authorities

A geographical map of the NERC Regional Entities and the Balancing Authorities is available at http://www.nerc.com/docs/oc/rs/BubbleMap_2011-04-12.jpg.

Yearly CPS2 Bounds Reports

The yearly CPS2 Bounds Reports are available at http://www.nerc.com/filez/rs.html.

References

Approved by the
Operating Committee
June 15, 2010

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Dynamic Transfer Reference Guidelines
Version 2

to ensure
the reliability of the
bulk power system

June 2010

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Revision History 27

Chapter 1 – Overview

Purpose

The purpose of this document is to provide guidance and encourage consistency in the industry on the responsibilities, requirements, and expectations placed upon parties involved in establishing a dynamic transfer.

It is not within the scope of this reference document to require any organization to modify any existing dynamic transfers.

Terms

ATTAINING BA — A BA bringing generation or load into its effective control boundaries through dynamic transfer from the Native BA.

DYNAMIC TRANSFER SIGNAL — The electronic signal used to implement a pseudo-tie or dynamic schedule using either a metered value or a calculated value.

INTEGRATION in the terms for dynamic schedule and pseudo-tie above means the value could be mathematically calculated or determined mechanically with a metering device.

NATIVE BA — A BA from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining BA.

Chapter 2 Dynamic Schedule versus Pseudo-tie Fundamentals

The key difference between pseudo-ties and dynamic schedules is often viewed only as a system control issue. Discussions are typically limited to how the transfer is implemented in each BA's ACE equations and in the associated energy accounting process. Pseudo-ties are accounted for by all parties as actual interchange and dynamic schedules are accounted for as scheduled interchange. However, there are other factors that must be considered when determining which type of dynamic transfer should be utilized for a given situation. The descriptions provided in this document are based on practical experience where dynamic transfers have been successfully implemented.

From a simple perspective, a dynamic schedule is a means of achieving a time-varying exchange of power where a traditional block scheduling is not sufficient. Examples might be the partial or complete exchange of regulating obligations (see *Appendix B — Supplemental Regulation Service as a Dynamic Schedule*), the temporary provision of power under a reserve sharing agreement, or the exchange of power to serve a real-time demand signal.

On the other hand, pseudo-ties are used (typically but not exclusively) to represent interconnections between two BAs at a generator or load similar to a *physical* tie line. These load/generators, however, are at locations where no other physical connection exists between the load/generation and the power system network of the responsible, attaining BA's traditional control boundaries defined by its physical tie lines. In the instance of a pseudo-tie, the operational and procedural responsibility[1] for a load/generation is a key. In addition to system control responsibility that is traditionally considered, the responsibilities related to a pseudo-tie extend to such requirements as Disturbance Control Standard (DCS) recovery, load shedding, transmission and ancillary services, load forecasting, etc. associated with the load/generation.

Although both pseudo-ties and dynamic schedules involve time-varying quantities, unlike for a pseudo-tie, a dynamic schedule has no specific load/generation for which the attaining BA is operationally or procedurally responsible.

The choice of a pseudo-tie versus dynamic schedule can be adapted to suit any implementation between the native and attaining BAs – as long as both BAs agree which one is responsible for each of the obligations associated with the load/generation. For example, a pseudo-tie would typically be used to represent a generator owned by an attaining BA that is located within the physical tie line boundary of a native BA. However, a dynamic schedule implementation can be used in each BA's ACE equation as long as responsibility for obligations such as recovery during a DCS event are clearly understood and accepted by both BAs.

[1] Procedural responsibility refers to which Balancing Authority Area's and/or which Reliability Region's requirements will apply to the generator or load

Chapter 3 –Dynamic Transfer Implementation Considerations

Dynamic transfers can be used for, but not limited to the following scenarios:

- Transfer all, or a portion of, actual output of a specific generator(s) to another BA in real-time,
- Enable resources in one BA to provide the real-time power requirements for a load physically located in another BA, or
- Enable generators, loads, or both in one BA to supply one or more interconnected operations services to generators, loads, or both in another BA, or
- Provide a mechanism for reserve sharing, or
- Provide supplemental regulation.

The particular dynamic transfer method to be utilized for a specific operating arrangement may be dependent on some or all of the following:

- Desired service(s) to be provided,
- The capability to capture the dynamic transfer in system models,
- Responsibility for forecasting load,
- Responsibility for providing unit commitment and maintenance information, and
- EMS capability.

Each BA is obligated to fulfill its commitment to the Interconnection and not burden other BA(s) in the Interconnection. The use of a dynamic transfer does not in any way diminish this responsibility.

- Before implementing the dynamic transfer, all parties to the dynamic transfer must agree on all implementation issues.
- Any errors resulting from an improperly implemented or operated dynamic transfer (including inadvertent interchange accumulations) must be resolved between the involved parties.
- Dynamic transfers must NOT include any control offsets that are not explicitly compliant with the requirements set forth in the NERC reliability standards (e.g., unilateral inadvertent payback, Western Interconnection automatic time error control, etc.).
- Applicable tariff requirements of all involved, or affected, transmission providers and BA(s) must be met (this includes proper handling and accounting for energy losses).

- If the dynamic transfer includes a pre-arranged calculated assistance (or distribution of responsibility) between the native BA and the attaining BA for recovery from the loss of generation, then both BAs are responsible for ensuring that their respective DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002-0 — Disturbance Control Performance.
- The projected use of the transmission system for a dynamic transfer shall be modeled in the base case power flow study cases. Such modeling must be done for the dynamic transfer at each end of its range, and for as many other points within its range as required to ensure that the dynamic transfer will not cause reliability problems in real time.

From a system modeling perspective, the assignment of load or generation into the control response of another BA must be appropriately captured in the reliability analysis tools. It is the obligation of each BA involved in the dynamic transfer to ensure that the dynamic transfer of load or generation is coordinated with their Reliability Coordinator so that the method of dynamic transfer can be considered in the system modeling of the generation or load affected, and necessary data provision requirements are met.

- To assure proper resource application, it is the responsibility of the attaining BA dynamically transferring load into its effective boundaries through pseudo-ties to ensure that load forecasts and subsequent BA reporting reflect the load incorporated within its BA boundaries. Conversely, when a dynamic schedule is used to serve load within another BA area, the BA where the load is electrically connected (native BA) must include that load in its BA load forecast and any subsequent reporting as needed.
- It is the responsibility of both the native BA and attaining BA to model any generation or load serving dynamic transfers in their respective, power flow models and security applications. This modeling is required to ensure that both affected BAs study the generation or load regardless of the control boundary designations. This modeling also is necessary to ensure that each BA can see the impact of the dynamic transfer on their systems. .
- Dynamic transfers must not affect reliability adversely. If the reliability impact of a dynamic transfer that has been implemented as a pseudo-tie cannot be addressed adequately without modeling it in the IDC or other applicable security analysis system models that use scheduled values, then the dynamic transfer must be performed via a dynamic schedule.
- For both Pseudo-Ties and Dynamic Schedules — The BAs shall adjust the control logic that determines their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BAs.
    - Frequency Bias Setting — Each BA is required to review its Frequency Bias Setting on an annual periodicity. The BA may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change. Each BA, upon request from NERC, will report its Frequency Bias Setting, and the method for determining the setting.

The native, attaining, and intermediate BAs must carefully coordinate many aspects related to dynamic transfers. Failure to do so may result in the creation of reliability problems for the Interconnection, may create after-the-fact energy accounting and billing problems, and may

cause violations of industry standards. Below is a list of items that the affected BAs should consider prior to implementing a new dynamic transfer:

- Control offsets are compliant with applicable industry standards
- Tariff requirements are met
- DCS reporting requirements have been addressed
- Transmission service has been considered
- Need for inclusion in reliability tools has been addressed
- Transferred loads and/or generation are accounted for in energy dispatch
- Transferred loads and/or generation are still included in relevant security analysis tools
- Frequency Bias impacts have been addressed
- Contingency plans for loss of dynamic transfer signal have been addressed
- Contingency plans for network problems that prohibit the dynamic transfer
- Other industry compliance issues have been addressed
- Energy accounting practices are consistent, including losses
- Ancillary service provision has been addressed
- Impact on spinning reserve requirements have been addressed
- Impact on under-frequency load shedding relays have been addressed

Table 1 describes and outlines the obligations associated with the typical historical application of pseudo-ties and dynamic schedules related to many of the topics addressed above. In practical application, however, both the native and attaining BAs can agree to exchange the obligations from that shown in the Table 1.

Table 1 - Assignment of BA Obligations

BA's Obligation/modeling	Pseudo tie	Dynamic schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, native BA but may be re-assigned (wholly or a portion) to the attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services as required	Attaining BA	Native BA
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/native BA (as agreed)	Attaining/Native BA (as agreed)
ACE frequency bias calc/setting	The native and attaining BA(s) shall adjust the control logic that determines their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) by the pseudo-tie	The attaining BA should include the load from its dynamic schedule as a part of its forecast load to set frequency bias requirement. The native BA should change its load used to set frequency bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA
Note: This table contains the typical BA obligations that have been utilized throughout the industry for pseudo-ties and dynamic schedules. However, for any specific dynamic transfer implementation, both the native and attaining BAs can agree to exchange the obligations from that shown in the Table 1.		

Chapter 4 –Dynamic Schedule

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between BAs. A dynamic schedule typically does not change a BA's operational responsibility; that is, the native BA continues to exercise operational control over, and provides basic BA services to, the dynamically scheduled resources.

Dynamic schedules are to be accounted for as interchange schedules by the source, sink, and contract intermediary BA(s), both in their respective ACE equations, and throughout all of their energy accounting processes. Requirement to incorporate into the contract intermediary BA's ACE is subject to regional procedures.

All dynamic schedules used for supplemental regulation or to assign the control of generation, loads, or resources from one BA to another must meet the following requirements:

1. **Telemetry**

   Appropriate telemetry must be in place and incorporated by all affected BA(s) in accordance with all NERC reliability standards, in particular the Disturbance Control Performance standard.

2. **Transmission Service**

   Prior to implementation of the dynamic schedule of load or generation, all applicable NERC interchange reliability standards need to be met, including ancillary services and provision of losses.

   If transmission service between the source and sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, may have to be curtailed accordingly. All BAs involved in a dynamic schedule curtailment must also adjust the dynamic schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed dynamic schedule tag. Since dynamic schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.

3. **System Modeling**

   When a dynamic schedule is used to serve load within another BA area, the BA where the load is electrically connected (native BA) must include that load in its BA load forecast for both energy dispatch and security analysis and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. **Dynamic Schedule Coordination and Scheduling**

   Implementation of a dynamic schedule must be through the use of an interchange transaction between BA(s). As such, all dynamic schedules shall be implemented in accordance with NERC interchange standards.

   Energy exchanged between the source, sink, and intermediary BA(s) as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal) energy for the loads and/or resources. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

   The native BA must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.

   If the power flows associated with the dynamic schedule are expected to be bi-directional, two separate dynamic schedules are required (each schedule to be implemented as unidirectional following the "gen-to-load" direction convention). This expectation is a result of the fact that transmission service would be required for the dynamic schedules and most often import and export transmission services are provided as separate reservations.

5. **Contingency Response**

   Before implementation of the dynamic schedule, the involved BAs shall agree on a plan:

   - To operate during a loss of the dynamic schedule telemetry signals such that all involved BAs are using the same value (including periods of time when the interconnection between them is unavailable). The BA(s) may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

   - To serve the load during system conditions which prevent delivery of the dynamic schedule from the generation to the load.

   - To redispatch the generation that had served the dynamically scheduled load prior to the system conditions which prevent delivery from the generation to the load.

6. **Compliance with NERC Reliability Standards**

   The implementation of a dynamic schedule may confer upon the attaining BA additional responsibilities for compliance with NERC reliability standards for the load or generation that has been transferred.

Chapter 5 – Pseudo-Tie

Pseudo-ties are often employed to assign generators, loads, or both from the BA to which they are physically connected into a BA that has effective operational control of them. Thus, pseudo-ties often provide for change of BA operational responsibility from the native to the attaining BA and at the same time make the attaining BA provider of BA services. In practice, pseudo-ties may be implemented based upon metered or calculated values. All BAs involved account for the power exchange and associated transmission losses as actual interchange between the BAs, both in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native BA to the attaining BA must meet the following requirements:

1. **Telemetry**

   Prior to implementation of the pseudo-tie transfer of load or generation, all applicable NERC reliability standards need to be met, including:

   - common metering points
   - adequate communications infrastructure

   The requirement for common metering points and adequate communications infrastructure does not imply specific ownership of telemetry devices.

2. **Transmission Service**

   Prior to implementation of the pseudo-tie transfer of load or generation, each involved BA shall ensure that the dynamic transfer is implemented such that the tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.

   If transmission service between the native and attaining BA(s) is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints.

   Agreements must be in place with the applicable transmission providers to address the physical and/or financial provision of transmission losses.

3. **System Modeling**

   The attaining BA dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts used for energy dispatch and subsequent BA reporting reflect the load incorporated within its BA boundaries. The native BA would continue to consider this load in load forecasts used for security analysis.

If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and/or any other security analysis system models of the reliability entities impacted by the dynamic transfer, then the dynamic transfer must be implemented as a dynamic schedule.

4. **Pseudo-Ties Coordination and Scheduling**

   Subsequent to moving load or resources into an attaining BA through pseudo-tie transfers, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated among the attaining intermediary and native BAs in accordance with the NERC reliability standards.

   - The attaining BA assumes responsibility for BA services required by the assigned loads and/or resources. The attaining BA assumes all regulation, contingency reserves, and other BA responsibilities for the loads and/or resources in question.

   - Energy exchanged between the native and attaining BA(s) by the pseudo-tie method is accounted for by the associated revenue meter reading (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal.

5. **Contingency Response**

   Before implementation of the pseudo-tie transfer, the involved BAs shall agree on a plan:

   - To operate during a loss of the pseudo-tie transfer telemetry signal such that all involved BAs are using the same value (including periods of time when the interconnection between them is unavailable). The BA(s) may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

   - To serve the load during system conditions which prevent delivery of the pseudo-tie transfer from the generation to the load.

   - To redispatch the generation that had served the pseudo-tie transfer load prior to the system conditions which prevent delivery from the generation to the load.

6. **Compliance with NERC Operating Standards**

   The implementation of pseudo-tie transfers may confer upon the attaining BA additional responsibilities for compliance with NERC reliability standards for the load or generation that has been transferred.

Appendix A —ACE Equation Implications of Dynamic Transfers

$$ACE = \{[\text{Net Actual Interchange}] - [\text{Net Schedule Interchange}]\} - 10F_b (F_A - F_S) - I_{ME} \quad (1)$$

$$ACE = \{[NI_A] - [NI_S]\} - 10F_b (F_A - F_S) - I_{ME} \quad (2)$$

$$ACE = \{[(NI_a) + (NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + NI_{ARSE} - NI_{ARSI})]$$

$$- [(NI_s) + (- NI_{SDSGE} + NI_{SDSGI} + NI_{SDSLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})] \}$$
$$- 10F_b (F_A - F_S) - I_{ME} \quad (3)$$

where:

Net Actual Interchange (NIA)

Affected by pseudo-ties/AGC interchanges

NI_A **=** (SUM of Tie Lines**) + (**SUM of Pseudo-Ties**)**

$NI_A = (NI_a) + (NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + NI_{ARSE} - NI_{ARSI})$

where:

NI_a	=	Net sum of tie line flows
NI_{APTGE}	=	sum of AGC interchange generation external to the attaining BA.
NI_{APTGI}	=	sum of AGC interchange generation internal to the BA (native BA).
NI_{APTLE}	=	sum of AGC interchange load external to the BA (attaining BA).
NI_{APTLI}	=	sum of AGC interchange load internal to the BA (native BA).
NI_{ARSE}	=	supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via pseudo-tie. See Appendix C.
NI_{ARSI}	=	Supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via pseudo-tie. See Appendix C.

and where values for all generation and load terms are assumed to be positive quantities

Net Scheduled Interchange (NIS)

Affected by dynamic schedules and supplemental regulation services.

NI_S = (SUM of non-dynamically scheduled transactions) + (SUM of Dynamic Schedules)

$NI_S = (NI_s) + (-NI_{SDSGE} + NI_{SDSGI} + NI_{SDSLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})$

where :

NI_s =	Net sum of non-dynamically scheduled transactions,
NI_{SDSGE} =	Sum of dynamically scheduled generation external to the attaining BA,
NI_{SDSGI} =	Sum of dynamically scheduled generation internal to the native BA,
NI_{SDSLE} =	Sum of dynamically scheduled load external to the attaining BA,
NI_{SDSLI} =	Sum of dynamically scheduled load internal to the native BA,
NI_{SRSE} =	Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service). See Appendix B,
NI_{SRSI} =	Supplemental regulation service internal to the BA (BA selling the supplemental regulation service). See Appendix B, and

where values for all generation and load terms are assumed to be positive quantities.

Terms Unaffected by Dynamic Transfers

F_b = BA Frequency Bias

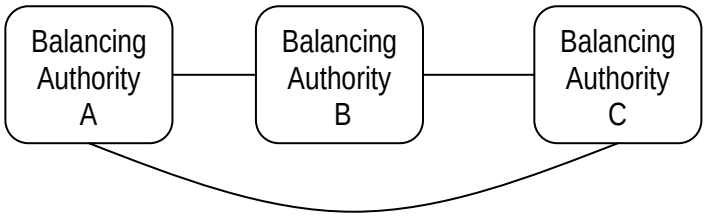
F_A = Actual Frequency

F_S = Scheduled Frequency

I_{ME} = Meter Error Correction

The following sections show which specific component should be used by each involved BA to reflect each type of dynamic transfer in its ACE equation.

Application of Pseudo-ties in ACE by BA(s)



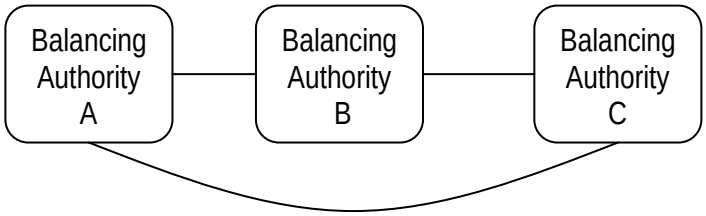
(A→B) BA(s) A and B are Adjacent BA(s).
(A→C→B) BA C is an Intermediate BA.
(A→C) BA(s) A and C are Adjacent BA(s).
(A→B→C) BA B is an Intermediate BA.

Table A-1

			BA A	**BA B**	**BA C**
P1	Generator From **A** to **B** Path **A→B**	**A→B**	**NI_{APTGI}**	**NI_{APTGE}**	—
P2	Generator From **A** to **B** Path **A→C→B**	**A→C** **C→B**	**NI_{APTGI}** —	— **NI_{APTGE}**	**NI_{APTGE}** **NI_{APTGI}**
P3	Generator From **A** to **C** Path **A→C**	**A→C**	**NI_{APTGI}**	—	**NI_{APTGE}**
P4	Generator From **A** to **C** Path **A→B→C**	**A→B** **B→C**	**NI_{APTGI}** —	**NI_{APTGE}** **NI_{APTGI}**	— **NI_{APTGE}**
P5	Load From **A** to **B** Path **A→B**	**A→B**	**NI_{APTLI}**	**NI_{APTLE}**	—
P6	Load From **A** to **B** Path **A→C→B**	**A→C** **C→B**	**NI_{APTLI}** —	— **NI_{APTLE}**	**NI_{APTLE}** **NI_{APTLI}**
P7	Load From **A** to **C** Path **A→C**	**A→C**	**NI_{APTLI}**	—	**NI_{APTLE}**

P8	Load From **A** to **C** Path **A→B→C**	**A→B** **B→C**	— **NI_{APTLI}**	**NI_{APTLE}** **NI_{APTLI}**	**NI_{APTLE}** —

Application of Dynamic Schedules in ACE by BA(s)



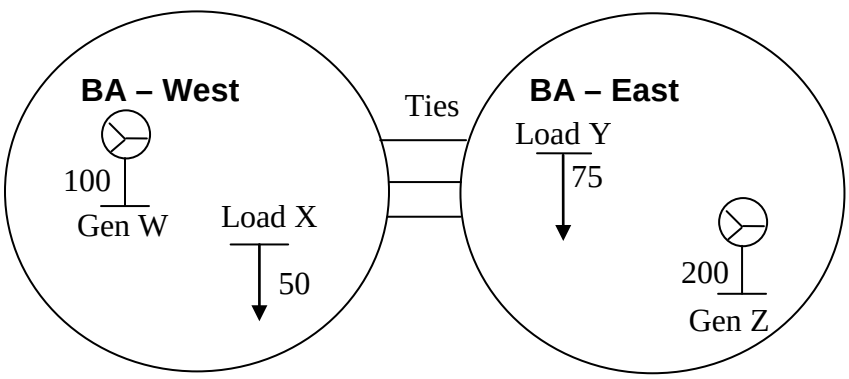
(A→B) BA(s) A and B are Adjacent BA(s).
(A→C→B) BA C is an Intermediary BA.
(A→C) BA(s) A and C are Adjacent BA(s).
(A→B→C) BA B is an Intermediary BA.

Table A-2

			BA A	**BA B**	**BA C**
S1	Generator output From **A** to **B** Path **A→B**	**A→B**	**NI_{SDSGI}**	**NI_{SDSGE}**	—
S2	Generator output From **A** to **B** Path **A→C→B**	**A→C** **C→B**	**NI_{SDSGI}** —	— **NI_{SDSGE}**	**NI_{SDSGE}** **NI_{SDSGI}**
S3	Generator output From **A** to **C** Path **A→C**	**A→C**	**NI_{SDSGI}**	—	**NI_{SDSGE}**
S4	Generator output From **A** to **C** Path **A→B→C**	**A→B** **B→C**	**NI_{SDSGI}** —	**NI_{SDSGE}** **NI_{SDSGI}**	— **NI_{SDSGE}**

S5	Serve a Load In **B** from **A** Path **A→B**	**A→B**	**NI_{SDSLI}**	**NI_{SDSLE}**	—
S6	Serve a Load In **B** from **A** Path **A→C→B**	**A→C** **C→B**	**NI_{SDSLI}** —	— **NI_{SDSLE}**	**NI_{SDSLE}** **NI_{SDSLI}**
S7	Serve a Load In **C** from **A** Path **A→C**	**A→C**	**NI_{SDSLI}**	—	**NI_{SDSLE}**
S8	Serve a Load In **C** from **A** Path **A→B→C**	**A→B** **B→C**	— **NI_{SDSLI}**	**NI_{SDSLE}** **NI_{SDSLI}**	**NI_{SDSLE}**

Numeric Examples



Assume: Net sum of tie flows = 0,
Net sum of non-dynamically scheduled transactions = 0,
$F_S = F_A$,
and $I_{ME} = 0$

In these examples, BA West will become the attaining BA for load Y and generator Z. Similarly, BA East will become the attaining BA for load X and generator W.

Using Dynamic Schedules

Using Table A-2, rows S1 and S5, to obtain the correct net scheduled interchange terms for the dynamic schedules, the ACE equation for BA West becomes:

$$\begin{aligned} ACE_{\text{BA West}} &= NI_A - NI_S = NI_A - (NI_s - NI_{SDSGE} + NI_{SDSGI} + NI_{SDSLE} - NI_{SDSLI}) \\ &= NI_A - (NI_s - \text{Gen Z} + \text{Gen W} + \text{Load Y} - \text{Load X}) \end{aligned}$$

Substituting the values in the example as positive quantities, the equation becomes:

$$\begin{aligned} ACE_{\text{BA West}} &= 0 - (0 - 200 + 100 + 75 - 50) \\ &= 0 - (-75) = 75 \end{aligned}$$

Using Pseudo-Ties

Using Table A-1, rows P1 and P5, to obtain the correct net actual interchange terms for the pseudo-ties, the ACE equation becomes:

$$ACE_{\text{BA West}} = NI_A - NI_S = (NI_a + \text{Gen Z} - \text{Gen W} - \text{Load Y} + \text{Load X}) - NI_S$$

Substituting the values in the example as positive quantities, the equation becomes:

$$\begin{aligned} ACE_{\text{BA West}} &= (0 + 200 - 100 - 75 + 50) - 0 \\ &= 75 \end{aligned}$$

Using both Dynamic Schedules and Pseudo-ties

Assume that the generation will be modeled as dynamic schedules and the loads as pseudo-ties. Using Table A-2, Row S1 and Table A-1, Row P5 to obtain the correct Net Scheduled Interchange and Net Actual Interchange terms for the dynamic transfers, the ACE equation for BA West becomes:

$$ACE_{\text{BA West}} = NI_A - NI_S = (NI_a - \text{Load Y} + \text{Load X}) - (NI_s - \text{Gen Z} + \text{Gen W})$$

Substituting the values in the example as positive quantities, the equation becomes:

$$\begin{aligned} ACE_{\text{BA West}} &= (0 - 75 + 50) - (0 - 200 + 100) \\ &= (-25) - (-100) \\ &= -25 + 100 = 75 \end{aligned}$$

Note: In all cases the ACE value is the same regardless of the dynamic transfer method(s) used.

Appendix B — Supplemental Regulation Service as a Dynamic Schedule

Supplemental regulation service is when one BA provides part of the regulation requirements of another BA. The BA(s) implement a dynamic schedule incorporating the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the scheduled interchange component of the ACE equation for both BA(s). Care should be taken to maintain the proper sign convention to ensure proper control, with the BA purchasing regulation service subtracting the supplemental regulation service from the scheduling component of their ACE while the BA providing the service adds it to the scheduling component of their ACE.

If the supplemental regulation service includes a calculated assistance between the native BA and the attaining BA for recovery from the loss of generation, then both BA(s) are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002 — Disturbance Control Performance.

ACE equation modifications required for supplemental regulation service:

ACE Equation Modifications

Typically:

$ACE = (NI_A - NI_S) - 10F_b (F_A - F_S) - I_{ME}$

where:

NI_A = Net Actual Interchange

NI_S = Net Scheduled Interchange

Fb = BA Frequency Bias

F_A = Actual Frequency

F_S = Scheduled Frequency

I_{ME} = Meter Error Correction

For a DYNAMIC SCHEDULE the NI_A remains unchanged, but to implement supplemental regulation service, the NI_S term becomes:

$$NI_S = NI_s - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI}$$

where:

NI_s = Net sum of non-dynamically scheduled transactions

NI_{SDSGE} = sum of dynamically scheduled generation external to the BA (attaining BA)

NI_{SDSGI} = sum of dynamically scheduled generation internal to the BA (native BA)

NI_{SDSLE} = sum of dynamically scheduled load external to the BA (attaining BA)

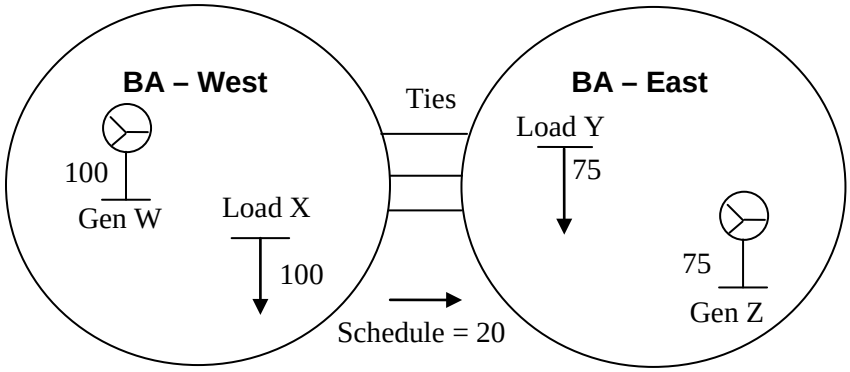
NI_{SDSLI} = sum of dynamically scheduled load internal to the BA (native BA)

NI_{SRSE} = Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service)

NI_{SRSI} = Supplemental regulation service internal to the BA (BA selling the supplemental regulation service)

and where supplemental regulation service for an overgeneration condition is assumed to be negative and for undergeneration it is positive to achieve the desired effect via NI_S on ACE as described in the "**NAESB WEQ Area Control Error (ACE) Equation Special Cases Standards - WEQBPS – 003-000**"

Supplemental Regulation as Dynamic Schedule - Numeric Example



Assume: Net sum of tie flows = 0,
Net sum of non-dynamically scheduled transactions = 20
Mw from BA-West to BA-East ,
$F_S = F_A$,
and $I_{ME} = 0$

In this example, BA-West will become the BA purchasing 15 Mw of supplemental regulation. Similarly, BA-East will become the BA selling 15 Mw of supplemental regulation.

Using the correct net scheduled interchange terms for supplemental regulation as a dynamic schedule, the ACE equation for BA-West becomes:

$$ACE_{BA\text{ - }West} = NI_A - NI_S$$
$$= NI_A - (NI_s - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})$$

simplifying for applicable terms for this example yields,

$$= NI_A - (NI_s - NI_{SRSE})$$

Since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

$$ACE_{BA\text{ - }West} = 0 - (20 - 15)$$
$$= 0 - (5) = -5$$

Similarly, the ACE equation for BA-East becomes:

$$ACE_{BA\text{ - }East} = NI_A - NI_S$$
$$= NI_A - (NI_s - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})$$

simplifying for applicable terms for this example yields,

$$= NI_A - (NI_s + NI_{SRSI})$$

Again since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

$$\begin{aligned} ACE_{BA\text{ - }East} &= 0 - (-20 + 15) \\ &= 0 - (-5) = 5 \end{aligned}$$

Appendix C — Supplemental Regulation Service as a Pseudo-Tie

Supplemental regulation service is when one BA provides all or part of the regulation requirements of another BA. The BA(s) implement a pseudo-tie incorporating the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the actual interchange component of the ACE equation for both BA(s). Care should be taken to maintain the proper sign convention to ensure proper control.

If the supplemental regulation service includes a calculated assistance between the native BA and the attaining BA for recovery from the loss of generation, then both BA(s) are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002 — Disturbance Control Performance.

ACE equation modifications required for supplemental regulation service:

ACE Equation Modifications

Typically:

$ACE = (NI_A - NI_S) - 10F_b (F_A - F_S) - I_{ME}$

where:

NI_A = Net Actual Interchange
NI_S = Net Scheduled Interchange
Fb = BA Frequency Bias
F_A = Actual Frequency
F_S = Scheduled Frequency
I_{ME} = Meter Error Correction

For a PSEUDO-TIE with supplemental regulation, the NI_S remains unchanged, but the NI_A term becomes:

$NI_A = NI_a + (NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + N_{ARSE} - N_{ARSI})$

where:

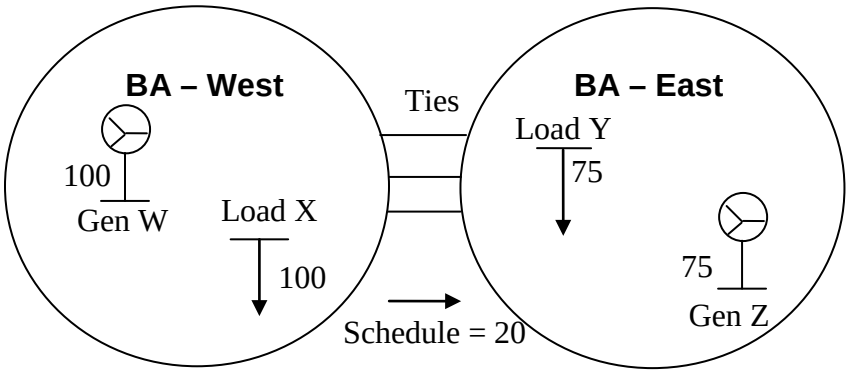
NI_a	=	Net sum of tie line flows
NI_{APTGE}	=	sum of AGC interchange generation external to the attaining BA.
NI_{APTGI}	=	sum of AGC interchange generation internal to the BA (native BA).
NI_{APTLE}	=	sum of AGC interchange load external to the BA (attaining BA).
NI_{APTLI}	=	sum of AGC interchange load internal to the BA (native BA).

NI_{ARSE} = supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via pseudo-tie.

NI_{ARSI} = supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via pseudo-tie.

As with dynamic schedules, for both the purchasing and selling BAs, supplemental service being provided to alleviate overgeneration has a negative sign, while supplemental service being provided to alleviate undergeneration has a positive sign.

Supplemental Regulation as Pseudo-Tie - Numeric Example



Assume: Net sum of tie flows = 0,
Net sum of non-dynamically scheduled transactions = 20 Mw
from BA-West to BA-East ,
$F_S = F_A$,
and $I_{ME} = 0$

In this example, BA-West will become the BA purchasing 15 Mw of supplemental regulation. Similarly, BA-East will become the BA selling 15 Mw of supplemental regulation.

Using the correct net actual interchange terms for supplemental regulation as a pseudo-tie, the ACE equation for BA-West becomes:

$$ACE_{BA\text{ - }West} = NI_A - NI_S$$
$$= (NI_a + NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + N_{ARSE} - N_{ARSI}) - NI_S$$

simplifying for applicable terms for this example yields,

$$= (NI_a + N_{ARSE}) - NI_S$$

Since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

$$ACE_{BA\text{ - }West} = (0 + 15) - 20$$
$$= 15 - 20 = -5$$

Similarly, the ACE equation for BA-East becomes:

$$ACE_{BA\text{ - }East} = NI_A - NI_S$$
$$= (NI_a + NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + N_{ARSE} - N_{ARSI}) - NI_S$$

simplifying for applicable terms for this example yields,

$$= (NI_a - N_{ARSI}) - NI_S$$

Again since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

$$\begin{aligned} ACE_{BA\text{ - }East} &= (0 - 15) - (-20) \\ &= -15 + 20 = 5 \end{aligned}$$

Revision History

Revision History			
Version	**Date**	**Action**	**Change Tracking**

Geomagnetic Disturbance Reference Document

Version 2

Introduction

Geomagnetic Disturbances (GMDs) are capable of causing serious disruptions to electric power systems, especially in the northern United States and Canada. This Reference Document explains how GMD watches, alerts, and warnings are provided to the Reliability Coordinators and other operating entities in the Eastern, ERCOT, TransEnergie, and Western Interconnections.

The National Oceanic and Atmospheric Administrations Space Environmental Center (SEC – http://www.sec.noaa.gov/today.html), located in Boulder, Colorado, provides a solar disturbance forecasting service. Although SEC is unable to predict precisely when solar flares will occur, it is able to determine when the disturbance is just beginning.

The information from SEC is made available to the Midwest ISO (MISO), St. Paul, Minnesota office, which has been designated to receive and disseminate notifications of possible GMDs to Reliability Coordinators, balancing authorities, and transmission operators in the Eastern and ERCOT Interconnections. The information from SEC is also made available to Bonneville Power Administration (BPA), which has been designated to receive notifications of possible GMDs and to disseminate such notifications to Reliability Coordinators and other operating entities within the Western Interconnection. The TransEnergie Interconnection receives notifications of possible GMDs from the Solar Terrestrial Dispatch Center.

Terms

The complete Glossary of Solar Terrestrial Terms is located at http://www.sec.noaa.gov/info/glossary.html.

A-Index — A daily index of geomagnetic activity derived as the average of the eight 3-hourly A-indices.

A-Index Watch — An A-Index Watch is issued when the daily Boulder, Colorado A-index is predicted to be greater than 20, 30, 50, or 100, with one day or greater lead-time, in the daily forecasts issued by SEC. A-index watches are issued for valid times corresponding to entire calendar days, based upon the daily analyses and forecasts produced by SEC. They serve as a long lead-time prediction of the expected trend in geomagnetic activity, within the limits of what the 24-hour A-index value can describe.

Ap-Index — An averaged planetary A-Index based on data from a set of specific stations.

Flare — A sudden eruption of energy on the solar disk lasting minutes to hours, from which radiation and particles are emitted.

Geomagnetic Storm — A worldwide disturbance of the earth's magnetic field, distinct from regular diurnal variations.

K-Index — A 3-hourly quasi-logarithmic local index of geomagnetic activity relative to an assumed quiet-day curve for the recording site. Range is from 0 to 9. The K-index measures the deviation of the most disturbed horizontal component.

K-Index Warning — K-Index Warnings are issued and/or extended for any period with expected values of K equal to or greater than 4. Higher K-Index Warnings supersede lower ones. A more thorough description of K-Index Warnings is provided at http://www.sec.noaa.gov/alerts/description.html#K. K-Index Warnings are issued by SEC under two conditions:

1. Warning of expected onset of geomagnetic activity, and/or,
2. Warning of expected persistence of geomagnetic activity.

K-Index Alert — K-Index Alerts, for values of K-4 through K-9, are issued on a near real-time criteria, based on thresholds of deflection from quiet-day curve values for geomagnetic field components over synoptic, 3-hour periods. A more thorough description of K-Index Alerts is provided at http://www.sec.noaa.gov/alerts/description.html#K.

Explanation of Geomagnetic Disturbance Watches, Warnings and Alerts

The following table defines geomagnetic activity in terms of the A and K Indexes. "A" refers to the 24-hour A-Index observed at a mid-latitude observatory such as Fredericksburg, Virginia, not the planetary A-Index (Ap) that is based on data from a set of specific stations. The K-Indices are, likewise, mid-latitude values.

NOTE: Sudden commencements are indicated by beginning times, given to the nearest minute. Gradual commencements are indicated by beginning times, to the nearest hour.

Activity	***A and K Indexes***
Quiet	A < 7, usually no K-indices > 2
Unsettled	7 < A < 15, usually no K-indices > 3
Active	15 < A < 30, a few K-indices of 4
Minor geomagnetic storm	30 < A < 50, K-indices mostly 4 and 5
Major geomagnetic storm	50 < A < 100, K-indices mostly 5 and 6
Severe geomagnetic storm	A > 100, some K-indices 7 or greater

Minimum Reporting Requirements

Each Interconnection shall designate an operating entity (e.g. a Reliability Coordinator) to receive geomagnetic disturbance watches, alerts and warnings. All K-7 or higher GMD warnings and alerts shall be routed by established procedures to operating entities within the applicable Interconnection.

The Geomagnetic Disturbance Phenomenon

Solar flares cause relatively rapid transient fluctuation in the earth's magnetic field (geomagnetic field). These transient geomagnetic field variations produce an induced earth-surface-potential (ESP). The ESP can be on the order of five to ten volts per mile, and results in geomagnetically induced currents (GIC). These currents cause abnormal disturbances in communication, pipeline, railroad signal, and power systems that are grounded to the earth at points remote from each other. The periodicity of the GIC varies over a very wide cycle range. Micro-pulsations are superimposed on alternations spanning a very wide band of low frequencies. Some GIC have a fundamental period on the order of minutes, appearing as quasi-dc compared to 60 Hz or higher frequency.

Geomagnetic storms can produce spurious, quasi-dc currents in electric power systems. Power system disturbances due to the geomagnetic storms were noted as early as 1940. Other major power system disturbances due to geomagnetic storms occurred in 1957, 1958, 1968, 1970, 1972, 1974, 1979, 1982, 1983, and 1989.

Studies have reaffirmed that geological conditions override the effect of latitude. The magnitude of the induced earth-surface-potential (ESP) per mile is normally greater with increasing latitude, however, in areas, which are located over a highly resistive igneous rock formation, the ESP forces large quasi-dc current flows over the transmission system rather than through the higher resistivity surface rock.

Geomagnetic storms cause large fluctuations in the earth's magnetic field and differences in potential between points of ground. It is known that during these storms, geomagnetically induced currents (GIC) are produced in the electric power systems. These GICs enter and exit through grounded neutrals of wye-connected transformers. The GICs can be many times larger than the Root Mean Square (RMS) value of the AC exciting current, resulting in severe half-cycle saturation and increased transformer VAR demands. Problems, which have been detected during solar magnetic disturbances, are:

- ✓ Unusual noises and heating in transformers
- ✓ Real and reactive power swings
- ✓ Elevated neutral amperes in transformers
- ✓ Frequency excursions
- ✓ Tripping of capacitor banks by neutral ground current
- ✓ Harmonic currents
- ✓ Hunting of automatic LTC transformers
- ✓ Voltage fluctuations
- ✓ Communication system problems
- ✓ Oscillograph operations
- ✓ Operation or non-operation of protective relays
- ✓ Negative sequence relays alarmed

Approved by the
Operating Committee
June 15, 2010

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Performance Standards Reference Guidelines

Version 1

to ensure
the reliability of the
bulk power system

June 2010

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Chapter 1 – General [Area Interchange Error Training Document – ACE Equation]

This reference document is intended to provide the reader with a better understanding of the balancing-related standards. While the information can provide clarity on potential ways to demonstrate compliance, the document should not be used by compliance staff as a benchmark to measure compliance or create new obligations not found in the standards. Should any difference or conflict be found between this document and the standards, the standards take precedence.

General [Area Interchange Error Training Document – ACE Equation]

This document provides instructions for calculating the control performance of the balancing authority (BA) and instructions and forms to complete the surveys. It is intended to serve industry participants as a "how to" guide for application and interpretation of the performance standards.

The BA's Area Control Error (ACE) is the basis for the calculation of control parameters used to evaluate control performance. ACE is used to determine a BA's control performance with respect to the BA's impact on system frequency. The value of ACE to be used throughout the calculation of control parameters is directed by standards to reflect its actual value and exclude short excursions due to transient telemetering problems or other influences such as control algorithm actions. Erroneous readings such as "spikes" due to telemetering error or other false influences should be excluded from the calculations. However, the computations should include ALL of the non-erroneous intervals (i.e., do not exclude intervals that contain disturbance conditions). This ACE is defined as net actual interchange less net scheduled interchange less frequency bias contribution and meter error. It does not include offsets (e.g., unilateral inadvertent payback, WECC's automatic time error correction, etc.).

These measurements of control performance apply to all conditions (i.e., both normal and disturbance conditions). The BA continuously monitors its control performance and reports the compliance results at the end of each month.

Targeted Frequency Bounds

The targeted frequency bounds, epsilon 1 ($\in_1$and epsilon 10 ($\in_{10}$), are based on historic measured frequency error. These bounds, typically in millihertz (mHz), embody the targeted frequency characteristics used for developing the Control Performance Standard. Each Interconnection is assigned its own frequency bounds.

The Targeted Frequency Bound for an Interconnection is computed as follows:

1. The NERC Resources Subcommittee (RS) defines a desired frequency profile.
2. The NERC RS collects frequency data from designated providers within each Interconnection. The frequency bounds are the RMS of the one- and ten-clock-minute averages of the frequency error (deviation) from schedule. These values are derived from

data samples over a given year. The NERC RS calculates and then sets the targeted frequency bounds, $\in_1$ and $\in_{10}$, to recognize the desired performance profile of frequency for each Interconnection.

Compliance for BAs
A BA that does not comply with CPS is not providing adequate regulation services.

1. If a BA does not comply with the CPS, the BA is not permitted to provide regulation or other services related to control performance for any other BA(s) or other entities.
2. A BA failing to comply is directed by the standard to take immediate corrective action and achieve compliance within three months. If necessary, a BA is directed by the standard to buy sufficient supplemental regulation to achieve compliance.

Compliance for BAs Providing Regulation
A BA is not permitted to provide regulation or other services related to control performance for (an) other BA(s) or other entities external to that BA, if the former BA does not comply with the CPS.

Compliance for BAs Participating in Supplemental Regulation
A BA providing or receiving supplemental regulation will continue to be evaluated on the characteristics of its own ACE with the supplemental regulation service included. The compliance calculations for each of the affected BAs will not change.

Compliance for BAs Participating in Overlap Regulation

- **BAs Providing Overlap Regulation**
  A BA providing overlap regulation is to continue to be evaluated on the characteristics of the combined areas' ACE. The provider BA should calculate and use the sum of the frequency bias characteristics of itself and the BA for which it is providing the overlap regulation. Frequency bias minimums apply to each BA individually in these cases.
- **BAs Receiving Overlap Regulation**
  A BA receiving overlap regulation service is not to have its control performance evaluated.

Chapter 2 – Control Performance Standard 1, CPS1 [Area Interchange Error Training Document – ACE Equation]

Control Performance Standard 1, CPS1 [Area Interchange Error Training Document – ACE Equation]

CPS1 provides the BA with a frequency-sensitive evaluation of how well its demand requirements were met. The measure is not designed to be a visual indicator that an operator would use to control system generation, nor is it designed to address the issue of unscheduled power flows, or control of inadvertent interchange.

Metrics

Over a given period, the average of the clock-minute averages of a BA's [ACE divided by ten times its bias] times the corresponding clock-minute averages of the Interconnection's frequency error is to be less than or equal to a constant (epsilon 1 squared, the constant on the right-hand side of the following inequality):

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \in_1^2 \qquad or \qquad \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \le 1$$

where: $\mathbf{ACE_i}$ is the clock-minute average of ACE (as ACE is defined in Section A) and $\mathbf{B_i}$ is the frequency bias of the BA. For those areas with variable bias, an accumulation of $ACE/(-10B_i)$ is made through the AGC cycles of a minute, and the averaged value at the end of the minute should be saved as the clock-minute value of $ACEi/(-10B_i)$, $\in_1$ in Hz, is a constant derived from the targeted frequency bound. It is the targeted RMS of one-minute average frequency error from a schedule based on frequency performance over an averaging period of a year. The bound is the same for every BA within an Interconnection.

$\mathbf{\Delta F_1}$ (delta F sub one) in Hz, is the clock-minute average of frequency error from schedule, $\Delta F = F_a - F_s$, where F_a is the actual (measured) frequency and Fs is scheduled frequency for the Interconnection.

i is representative of the individual BA,

Period is defined as:

a. one year for BA evaluation
b. one month for reporting and Resources Subcommittee review

Compliance

The fundamental measurement for CPS1 is that performance, as measured by percentage compliance, needs to be at least 100%.

It is possible for CPS1 percentage compliance to vary from –infinity to +infinity, depending on delta F and ACE magnitudes.

Control Compliance Rating = Pass if CPS1 ≥ 100%
Control Compliance Rating = Fail if CPS1 < 100%

CPS1 begins with a fundamental calculation called the compliance factor (CF). Its basic building block (called CF', or CF prime to distinguish it from CF as used later) is the quantity defined below, which essentially converts ACE to a form of frequency which can be compared with interconnection epsilon(s).

$$\text{CF'} = \left[\left(\frac{ACE}{-10B}\right) * \Delta F\right] \text{ Hz}^2$$

Note: that as written above this quantity is an instantaneous value, no averaging involved. CPS1 uses a 1-minute average base calculation, so CF' becomes

$$CF'_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right] \text{ Hz}^2$$

Note the units of this calculation are in terms of frequency squared. This is important in the calculations to follow, as comparison is made to epsilon squared to determine compliance.

The compliance factor, CF, is derived from CF' by dividing by epsilon squared:

$$CF = \frac{CF'}{(\in_1)^2}$$

CF is a (dimensionless) ratio that defines whether a BA's contribution to frequency deviation "noise" is greater than or less than the amount allowed. A value of 1 means exactly the amount of allowed frequency deviation-coincident "noise" has been contributed by the BA. Less than 1 means a "quieter" ACE characteristic. Negative means the BA is actually anticoincident with frequency deviation; generally a good thing as long as ACE magnitude is kept in check and the BA is not seriously over-controlling.

CPS1 then converts CF to a compliance percentage as follows:

$$CPS1\% = (2 - CF) * 100\%$$

This calculation is for any time interval. For compliance purposes, CPS1 percentage is calculated over the most recent 12 months (the month of the report plus the most recent 11 consecutive prior months). Epsilon can change, but since CPS1 is reported monthly, and epsilon would normally not be changed except on a month boundary, it is valid to calculate the monthly and the running 12-month CPS1 compliance as follows:

$$\mathbf{CPS1\%_{month} = (2 - CF_{month}) * 100\%}$$

where:

$$CF_{\text{month}} = \frac{CF'_{\text{month}}}{(\in_1)^2} \quad \text{and} \quad CF'_{\text{month}} = \frac{\sum_{\text{1 min. periods in month}} (CF_{\text{clock-minute}})}{\left[n_{\text{1min. periods in month}}\right]}$$

$$\mathbf{CPS1\%}_{\mathbf{12\text{-}month}} \mathbf{= (2\text{-}CF}_{\mathbf{12\text{-}month}}\mathbf{)}$$

where:

$$CF_{12-\text{month}} = \frac{\sum_{m=1}^{12}\left[CF_{\text{month}} \times n_{\text{1min. periods in month m}}\right]}{\sum_{m=1}^{12} n_{\text{1min. periods in month m}}}$$

"$n_{\text{1 min. periods in month m}}$" means the number of <u>valid</u> periods in the month (m), as described later herein. The reason for the 12-month calculation (running 12-month compliance) being different is to allow for possible changes to epsilon 1. It would be undesirable to retroactively change previous months' measured performance by using a different epsilon than was in effect for them originally. Also note that compliance percentages can be calculated for other time periods (month, day, shift hours, etc.) by replacing $CF_{12\text{-month}}$ in the above formula with the appropriate CF value.

Clock-minute average calculations

A clock-minute average is the average of the reporting BA's valid measured variable (i.e., for ACE and for frequency error, as well as for the BA's frequency bias, as defined above) for each valid sample during a given clock minute.

$$\left(\frac{\text{ACE}}{-10\text{B}}\right)_{\text{clock-minute}} = \frac{\sum_{\text{samples in clock-minute}} \left[\frac{\text{ACE}}{-10\text{B}}\right]}{n_{\text{samples in clock-minute}}}$$

or, for a BA with constant Bias

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\left[\sum_{\text{samples in clock-minute}} ACE\right]}{n_{\text{samples in clock-minute}}}\right)}{\text{-10B}}$$

and

$$\Delta F_{\text{clock-minute}} = \frac{\sum_{\text{samples in clock-minute}} \Delta F}{n_{\text{samples in clock-minute}}}$$

The BA's clock-minute Compliance Factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Accumulated Averages

The reporting entity can calculate and store compliance factors for a number of different reporting/analysis intervals. These factors can be used to calculate a CPS1 percentage for any desired time interval for any purpose desired.

for a single hour: $$\mathrm{CF}_{\text{clock-hour}} = \frac{\left[\sum_{\text{valid clock-minute averages in hour}} \mathrm{CF}_{\text{clock-minute}} \right]}{\mathrm{n}_{\text{valid clock-minute averages in hour}}}$$

for a month: $$\mathrm{CF}_{\text{month}} = \frac{\sum_{\text{hours-in-month}} [(\mathrm{CF}_{\text{clock-hour}})(\mathrm{n}_{\text{valid clock-minute averages in hour}})]}{\sum_{\text{hours-in month}} [\mathrm{n}_{\text{valid clock-minute averages in hour}}]}$$

for (running) 12 months: $$\mathrm{CF}_{\text{12-month}} = \frac{\sum_{1}^{12} (\mathrm{CF}_{\text{month}})(\mathrm{n}_{\text{valid clock-minute averages in month}})]}{\sum_{1}^{12} [\mathrm{n}_{\text{valid clock-minute averages in month}}]}$$

Interruptions in Data

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation sample pairs during that one-minute interval be present. The data pairs within a one-minute period need not be contiguous, but ACE and frequency data pairs should be simultaneous. Should an interruption in the recording of ACE or Frequency Deviation due to uncontrollable causes result in a one-minute interval not containing at least 50% of sample pairs of both ACE and Frequency Deviation, that one-minute interval is excluded from the calculation of CPS1.

Examples

Below is an example of the calculations needed for CPS1 monitoring and compliance. The example starts with the first hour of the first day of a month through to the end of the month, and the BA bias, B = –60 MW/0.1 Hz.

On Day 1, at the beginning of HE 0100, the area should calculate CF'clock-minute by multiplying the clock-minute average ACE (divided by ten times the area's bias) by the clock-minute average frequency error from schedule. Subsequent products are calculated for the remaining clock-minutes of the hour.

HE 0100:		***Minute 1***	***Minute 2***	***...***	***Minute 60***		
ACE	MW	-20	-10		-40		
ACE/-10B	Hz	-20/-10(-60) = .0333332	.0166667	…	.06666667	***Sum***	***CF'$_{\text{clock-hour}}$ = Σ(CF')/n***

ΔF	Hz	0.005	-0.005	...	0.005		
CF' = (ACE/-10B) x ΔF	Hz^2	-0.000167	0.000083	...	-0.000333	0.00525	0.000088 or 88 mHz^2
n = (# of 1-min averages)		1	1		1	60	

Note that n (# of 1-minute sample averages) is based on the number of valid samples over the hour. Since CPS1 uses 1-minute averages of ACE and frequency error (and there were no data anomalies in this hour), n = 60. The procedure shown above is repeated for each of the 24 hourly periods of each day. As the days of the month continue, the 24-hour period CF' clock-hour average-month values are averaged as shown below: At the end of the month, a CF'month can be calculated.

Hour		***Day 1***	***Day 2***	***...***	***Day 31***	***Sum***	***$CF'_{clock\text{-}hour\ average\text{-}month}$ = [Σ(CF' x n)]/Σ(n) mHz^2***
HE 0100	$CF'_{clock\text{-}hour}$	87.5	93.5	...	92.0		90.5
	n (# of averages)	60	59		57	1842	
	$CF'_{clock\text{-}hour}$ x n	5250	5516.5		5244	166,742	
HE 0200	$CF'_{clock\text{-}hour}$	90.0	85.0	...	89.5		87.5
	n	58	60		60	1830	
	$CF'_{clock\text{-}hour}$ x n	5220	5100		5370	160,170	
...	...	...	...	...	...		...
HE 2400	$CF'_{clock\text{-}hour}$	89.0	92.0	...	89.0		89.5
	n	60	59		59	1830	
	$CF'_{clock\text{-}hour}$ x n	5340	5428		5251	163,787	
		Total n				44,208	
		Total $CF'_{clock\text{-}hour\ average\text{-}month}$ x n				3,930,888	
		CF'_{month} = $\Sigma(CF'_{clock\text{-}hour\ average\text{-}month}$ x n)/ Σ (n)				88.9 mHz^2	

A rolling CF12-month

CF 12-month can be calculated using the CFmonth values.

	Month				***Year***	***Year***
	1	2	.. .	12	Sum	$CF'_{12\text{-}month}$
CF'_{month}	88.9	93.3	..	91.7		$[\Sigma(CF'_{month}$ X n)/Σ(n)] =
n	44,208	42,072	.	42,875	515,030	**91.3 mHz^2**
CF'_{month} X n	3,930,888	3,925,345		3,931,655	47,022,239	

Assuming this interconnection has a ☐1 of 10 mHz, then the CPS1 compliance percentage would be calculated as follows:

$$\mathbf{CF} = CF'_{12\text{-month}} / (\varepsilon_1)^2 = 91.3\ mHz^2 / (10)^2\ mHz^2 = 91.3 / 100 = \mathbf{.913}$$

$$\mathbf{CPS1\ \%} = (2 - CF) \times 100\% = (2 - .913) \times 100\% = (1.087) \times 100\% = \mathbf{108.7\%}$$

This results in a "passing" grade (12-month CPS1 should be at least 100%).

Surveys

Performance Standard surveys are conducted monthly to analyze and demonstrate each BA's level of compliance with the Control Performance Standards. Completed surveys should be provided each month, to the designee or portal representing the Region, by the tenth working day of the month following the month reported. Users should check with regions to determine reporting requirements.

Instructions for BA Survey

Using data derived from digital processing of the ACE signal, a representative from each BA will complete and submit CPS1 Form 1, "NERC Control Performance Standard Survey."
Hourly Table - Report the clock-hour average compliance factor (CF) for each of the 24 hourly periods and the total number of clock-minute sample averages in each clock-hour average.

CPS1 Standard Summary

CPS1	CPS1 Month	Report the monthly compliance factor, percent compliance, and number of clock-minute sample averages and enter in this cell. This value is for the month, only and is critical to correct evaluation of 12-month compliance.
	CPS1 Rolling 12 Month Value	Report the rolling 12-month compliance factor, percent compliance, and number of samples and enter in this cell. This is your calculation of the rolling compliance. NERC will also make the calculation based on your monthly submittals.
	Number of Valid Samples	Enter number of valid clock-minute averages in the profile hour and total.
	Unavailable Periods	Enter number of unavailable 1-min periods in the profile hour and column total.

Chapter 3 – Instructions for Regional and NERC Surveys

Instructions for Regional and NERC Surveys

From a review of the BAs' surveys, each Regional Survey Coordinator or RS member will ensure completion of CPS1 Form 2, "NERC Control Performance Standard — Regional Summary."

a. Review CPS1 Form 1 data received from each BA in the Region for uniformity, completeness, and compliance with the instructions. Iterate with BA survey coordinators where necessary.

b. Transfer the data from each Form to the appropriate columns on CPS1 Form 2 or its equivalent. Review the comments submitted and, if significant, identify them with the appropriate BAs.

c. Ensure forwarding of a copy each of the completed CPS Forms 1 and 2 or their equivalent to the NERC staff.

NERC staff will combine the Regional reports into a single summary report to be reviewed quarterly by the NERC Resources Subcommittee.

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NERC Control Performance Standard Survey

CPS1 Form 1 BA -

Region - Month -

ε_1 – Year - Time Zone -

H.E.	CF	%	# of Valid 1-min Averages		Unavailable Periods	
0100				Record the total month's number of valid 1-min sample averages from each of the 24 hourly profile periods		Record the total unavailable periods from each of the month's 24 hourly profile periods
0200						
0300						
0400						
0500						
0600						
0700						
0800						
0900						
1000						
1100						
1200						
1300						
1400						
1500						
1600						
1700						
1800						
1900						
2000						
2100						
2200						
2300						
2400						
CPS1 Month -						
CPS1 – Rolling 12 Month Value						

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NERC Control Performance Standard Survey – Regional Summary				
CPS1 Form 2				
Region -	**Month -**			
Date -	**Year -**			
ID #	**BA Name**	**Monthly CF**	**#Valid 1-min Averages**	**Monthly CPS1 %**

Chapter 4 – Control Performance Standard 2, CPS2

Control Performance Standard 2, CPS2

The second measure of the CPS survey is designed to bound ACE ten-minute averages and in doing so provides a means to limit excessive unscheduled power flows that could result from large ACEs.

Metrics

Over a given period, the clock ten-minute averages of a BA's ACE should be less than the constant on the right-hand side of the following inequality during at least a percentage of the period as specified herein:

$$AVG_{10-\text{minute}}(ACE_i) \leq L_{10}$$

where: $L_{10} = 1.65 \in_{10} \sqrt{(-10B_i)(-10B_s)}$

$\in_{10}$ in Hz, is a constant derived from the targeted frequency bound. It is the targeted RMS of ten-minute average frequency error from schedule based on a selected historical period of interconnection frequency performance. The bound, $\in_{10}$, is the same for every BA within an Interconnection. In the ideal, it is also equal to epsilon1 divided by the square root of 10.

1.65 is a constant used to convert the frequency target to 90% probability. It is the number of standard deviations from the mean of a statistical normal distribution (Gaussian distribution) that will result in a probability of noncompliance of 10% (i.e., compliance of 90%).

$\mathbf{B_i}$ in (negative) MW per tenth Hz, is the frequency bias of the BA.

$\mathbf{B_s}$ in (negative) MW per tenth Hz, is the sum of the frequency bias settings of the BAs in the respective Interconnection; for systems with variable bias, this is equal to the sum of the minimum frequency bias settings.

For those systems with variable bias, CPS2 becomes:

$$AVG_{10-\text{minute}}(ACE) \leq L_{10}$$

where:

$$L_{10} = 1.65 \in_{10} [-10AVG_{10-\text{minute}}(B_i)]\sqrt{\frac{B_s}{B_{\text{minimum}}}}$$

$B_{minimum}$ is the area's minimum allowed bias.

Compliance

CPS2 compliance is achieved if the 10-minute ACE averages satisfy the inequality above for 90% (or more) of the intervals in a calendar month. The percentage, described below, is referred to as the CPS2 compliance percentage, or CPS2%.

Control Compliance Rating = Pass CPS2% $\geq$ 90%

Control Compliance Rating = Fail CPS2% < 90%

The compliance percentage is calculated as follows:

$$CPS2\% = \left[1 - \frac{\text{Violations}_{\text{month}}}{\left(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}}\right)}\right] * 100$$

The $\text{Violations}_{\text{month}}$[1] are a count of the number of periods in which the average $\text{ACE}_{\text{clock-ten-minutes}}$ exceeded L_{10}. $\text{ACE}_{\text{clock-ten-minutes}}$ is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples (average ACE).

The $\text{Violations}_{\text{month}}$[2] are a count of the number of periods in which the average $\text{ACE}_{\text{clock-ten-minutes}}$ exceeded L_{10}. $\text{ACE}_{\text{clock-ten-minutes}}$ is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples (average ACE).

$$\text{Violation}_{\text{clock-ten-minutes}} = 0 \text{ if } \left|\frac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| \leq L_{10}$$

$$= 1 \text{ if } \left|\frac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| > L_{10}$$

Each area reports the total number of Violations and Unavailable Periods for the month.

Determination of Total Periodsmonth and Violationsmonth

Since the CPS2 Criterion says that ACE is averaged over a discrete time period, the same factors that limit Total $\text{Periods}_{\text{month}}$ will limit $\text{Violations}_{\text{month}}$. The calculation of Total $\text{Periods}_{\text{month}}$ and $\text{Violations}_{\text{month}}$, therefore, must be discussed jointly.

[1] Violation in the context of CPS2 means exceeding the L10 limit for one of the 6 ten-minute periods in a clock hour. There is no NERC compliance violation unless a Balancing Authority exceeds the L10 limit more than 10% of the ten-minute periods in the month.

[2] Violation in the context of CPS2 means exceeding the L10 limit for one of the 6 ten-minute periods in a clock hour. There is no NERC compliance violation unless a Balancing Authority exceeds the L10 limit more than 10% of the ten-minute periods in the month.

Each 24-hour period beginning at 0000 and ending at 2400 contains 144 discrete ten-minute periods (six periods more or less on Daylight Saving Time transition days). Each hour (HH) contains six discrete ten-minute periods, where period 1 spans HH:00$^+$ – HH:10, period 2 spans HH:10$^+$ – HH:20, period 3 spans HH:20$^+$ – HH:30, period 4 spans HH:30$^+$ – HH:40, period 5 spans HH:40$^+$ – HH:50, and period 6 spans HH:50$^+$ – (HH+1):00. For a system that samples ACE every four seconds, for example, the average ACE over a ten-minute period would be defined by the algebraic sum of 150 ACE samples (starting at HH:00:04 and ending at HH:10:00) divided by 150.

A CPS2 violation is recorded for any valid ten-minute period where the absolute value of average ACE is greater than L_{10}.

Chapter 5 – Interruption in the Recording of ACE – Valid Intervals

Interruption in the Recording of ACE – Valid Intervals

A condition may arise which may impact the normal calculation of Total $\text{Periods}_{\text{month}}$ and $\text{Violations}_{\text{month}}$. This condition is a sustained, unavoidable and uncontrollable interruption in the recording of ACE or one of its components.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. The samples need not be contiguous. Such a period is a valid interval. Should more than half of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval is not valid and is omitted from the calculation of CPS2.

Data Reporting

The BA is responsible for submitting the Control Performance Standard survey each month. In addition, the BA is responsible for retaining sufficient pertinent data that will enable reproduction of the performance calculations.

Figure 1 –- CPS2-L10 Compliance Calculation Examples

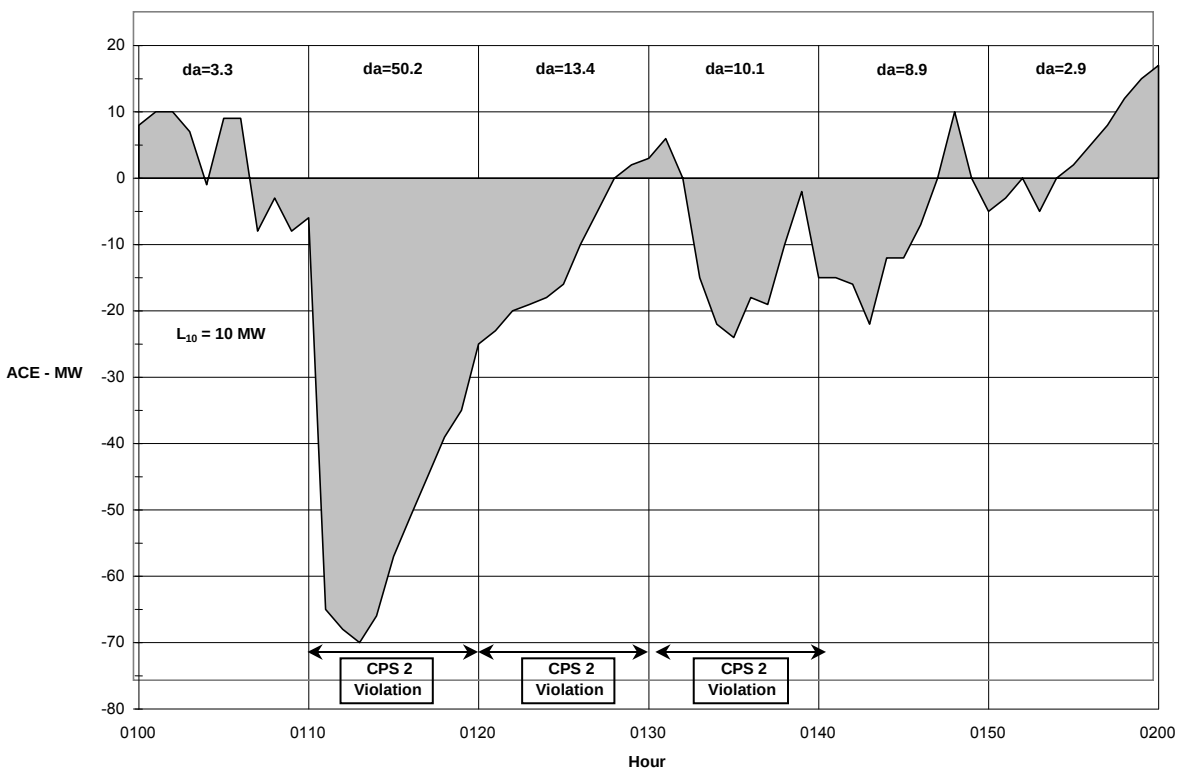

Figure 1 demonstrates various examples of CPS2 compliance determination. Note that Figure 1 is separated into six distinct clock-ten-minute periods. The absolute value of the algebraic mean of the ACE during each period, referred to as d_a, is compared to L10 (10 MW for this system) to

determine if there has been a violation for that period. Note that the fourth interval (0130 – 0140) has recorded a violation because the absolute value of the algebraic mean of 10.1 MW exceeds the L10 of 10 MW. Since disturbance conditions are included in the CPS2 calculation, violations are also recorded for the second and third intervals (0110–0120 & 0120–0130).

Figure 2 –- CPS2-L10 Compliance & Data Interruption Effects

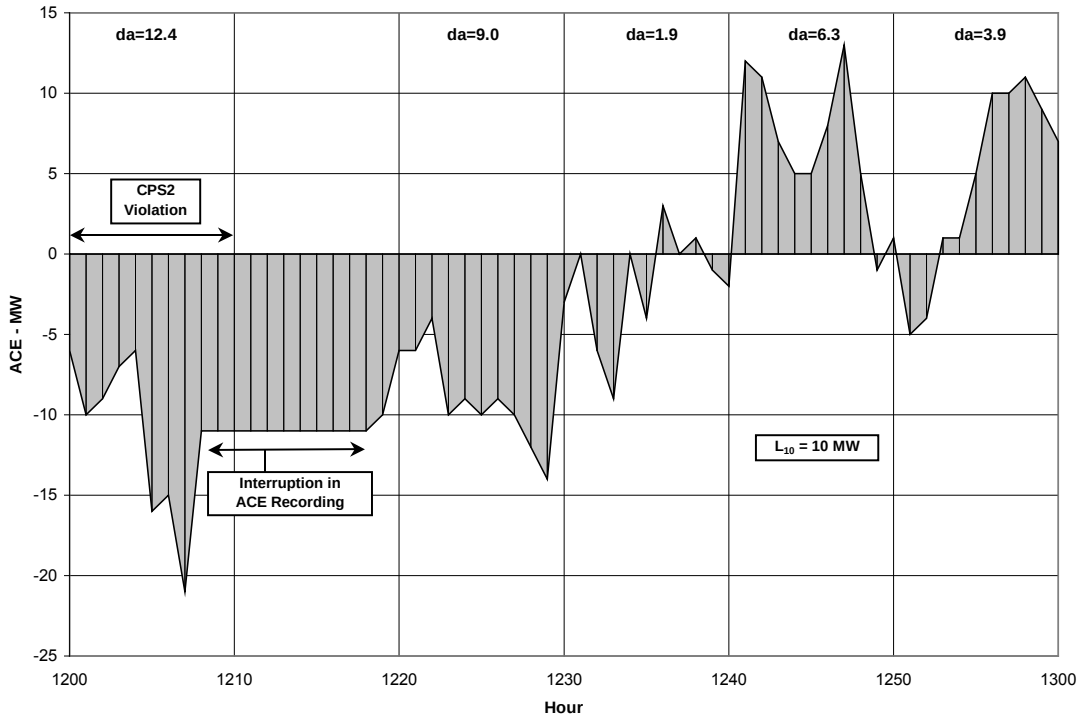

Figure 2 demonstrates various examples of L10 compliance coupled with an interruption in the recording of ACE. At 1208, ACE recording was interrupted and not returned until 1218. Since the ACE recording for the interval 1210 – 1220 did not include at least five minutes of data, this period is eliminated from CPS compliance analysis. In contrast, the first ten-minute interval of 1200 – 1210 is included in the analysis because ACE recording was interrupted only for the last two minutes of the interval. In fact, the first interval is in violation because the absolute algebraic mean of 12.4 MW exceeds the L_{10} of 10.0 MW. This algebraic mean of 12.4 MW was calculated for the eight minutes during which ACE was not interrupted. Thus, for this hour, there was one violation out of five valid intervals.

Surveys

Performance Standard surveys are submitted monthly to analyze and demonstrate each BA's level of compliance with the Control Performance Standards. Completed surveys are provided each month to the Region by the tenth working day of the month following the month being reported.

Instructions for BA Survey

Each BA will complete and submit CPS2 Form 1, "NERC Control Performance Standard Survey." For each of the 24 hourly periods of a day, report the monthly total number of CPS2 violations and the number of unavailable ten-minute periods. For example, if there was one

violation for hour ending 0100 every day of a 31-day month, a 31 would be entered for the 0100 hourly period.

CPS2 Standard Summary

CPS2	TOTAL	Sum the number of sample averages, the number of violations, and unavailable ten-minute intervals recorded on the hourly tables and enter the sums in this row for each column.
	CPS2 (%)	Calculate the CPS2 percentage compliance and enter in this row using the formulas and procedures described in Section C.

Instructions for Regional and NERC Surveys

From a review of the BAs' surveys, each Regional Survey Coordinator or RS member will ensure completion of CPS2 Form 2, "NERC Control Performance Standard — Regional Summary."

a. Review CPS2 Form 1 data received from each BA in the Region for uniformity, completeness, and compliance with the instructions. Iterate with BA survey coordinators where necessary.

b. Transfer the data from each Form to the appropriate columns on CPS Form 2. Review the comments submitted and, if significant, identify them with the appropriate BAs.

c. Forward a copy each of the completed CPS2 Forms 1 and 2 to the NERC staff.

d. NERC staff will combine the Regional reports into a single summary report that is reviewed by the NERC Resources Subcommittee quarterly.

NERC Control Performance Standard Survey

CPS2 Form 1

BA -

Region -

Month -

L_{10} –

Year -

H.E. CPT	Violations		Unavailable Periods	
0100		Record total violations for each of the 24 hourly profile periods		Record total unavailable periods for each of the 24 hourly profile periods
0200				
0300				
0400				
0500				
0600				
0700				
0800				
0900				
1000				
1100				
1200				
1300				
1400				
1500				
1600				
1700				
1800				
1900				
2000				
2100				
2200				
2300				
2400				
CPS2 Month -				

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NERC Control Performance Standard Survey – Regional Summary				
CPS2 Form 2				
Region -	**Month -**			
Date -	**Year -**			
ID #	**BA Name**	**Violations**	**Unavailable Periods**	**Monthly CPS2 %**

Chapter 6 – Disturbance Control Standard, DCS

Disturbance Control Standard, DCS

During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variation. Balancing areas, alone or collectively through reserve-sharing groups are expected to activate contingency reserve to cause recovery of ACE magnitude within fifteen minutes following the start of a disturbance. This dictates that a disturbance be defined. A disturbance is a sudden, unanticipated change (contingency) in resource(s) or demand. A sudden change is one that takes place over a minute or less. The DCS focuses on reportable disturbances.

Fifteen minutes is the existing recovery period duration which has evolved from debate over the appropriate way to measure the deployment of what has been measured as 10-minute reserves. It was argued that all balancing authorities need time to assess the validity of what appears to be a disturbance, and reserve-sharing groups need time to propagate calls for contingency reserves. Analyses were undertaken to determine probabilistically how lengthening the recovery period from 10 to 15 minutes would increase exposure to a second contingency. It was determined that the effect was very small, and recoverability from the next contingency is largely driven by reserve restoration timing, anyway. The 15 minute recovery standard was passed for recommendation by the NERC Resources Subcommittee in October, 1999.

For purposes of disturbance control compliance, reportable disturbances are contingencies that are greater than or equal to 80% of the most severe single contingency loss. The start of a disturbance is the time of the event as best defined by resource output decline, breaker opening, or other such indication – in the absence of such indication, the moment of first ACE deflection may be used. The start of the recovery period is the same moment as the start of the disturbance. Note that the start of a disturbance and its magnitude are determined by the resource or demand change, while recovery and compliance are determined by ACE.

Regions may optionally reduce the 80% reporting threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal load and generation excursions (e.g., pumped storage hydro, arc furnace, rolling steel mill, etc.) that influence ACE are not reportable disturbance conditions. Normal operating characteristics are excluded because DCS strives to measure the recovery from sudden, unanticipated changes in demand or supply-side resources.

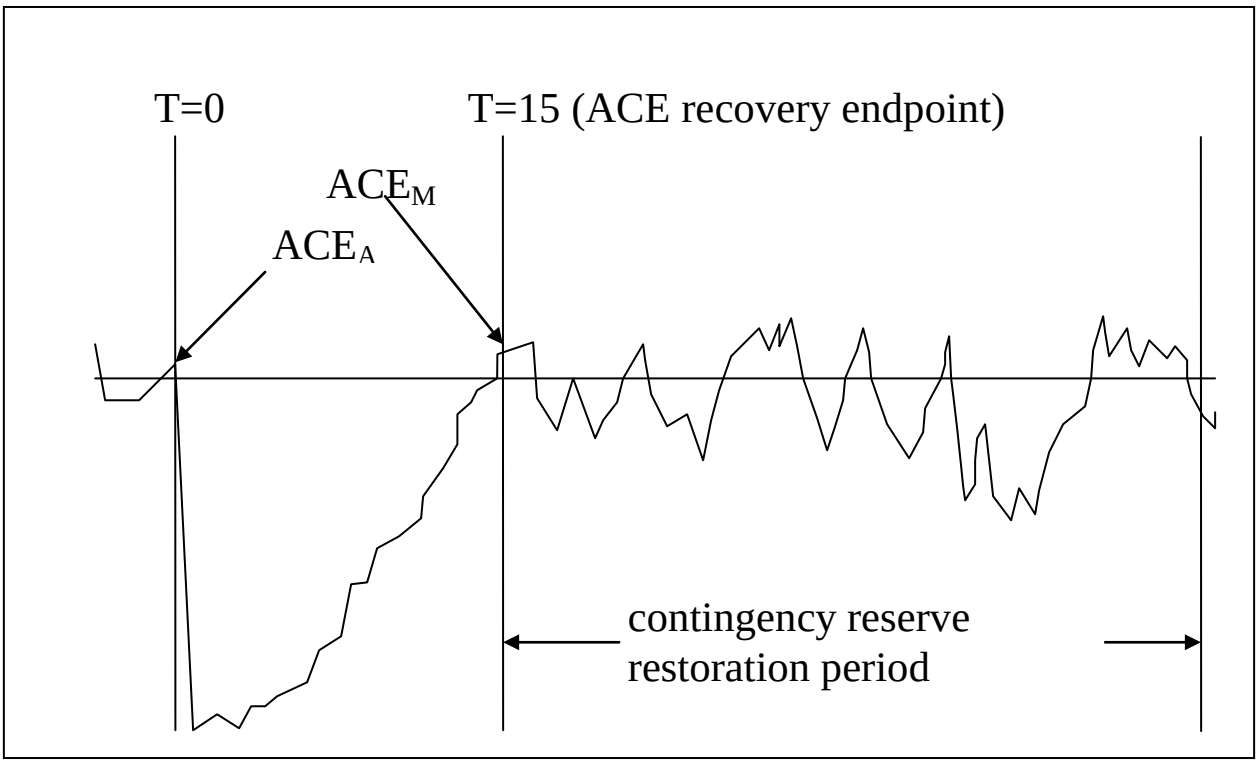
Metrics

Balancing Area

A BA is to return its ACE either to zero or to its pre-disturbance ACE level within a recovery time of fifteen minutes following the start of a disturbance. A BA may, at its discretion, measure its compliance based on the ACE measured fifteen minutes after the start of the disturbance, or on the maximum ACE recovery measured within the fifteen minutes following the start of the disturbance.

Reserve Sharing Group (RSG)

The disturbance control compliance for a BA within an RSG is based on the compliance of the RSG (according to the compliance method chosen). An RSG may, at its discretion, measure this recovery based on the combined ACE measured fifteen minutes after the start of the disturbance, or on the maximum combined coincidental ACE recovery measured within the fifteen minutes following the start of the disturbance event (not the time at which reserve activation was requested).



Relationships among ACE, the 15-minute recovery period, and the reserve restoration period

Compliance

A BA or RSG calculates and reports compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the BA's or the RSG's most severe single contingency loss. Regional Reliability Councils may, at their discretion, specify a lower reporting threshold. Disturbance Control Standard compliance is measured as the percentage recovery, Ri. Ri >= 100% represents full compliance.

For loss of generation:

if $ACE_A < 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

if $ACE_A \geq 0$

then $$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

where

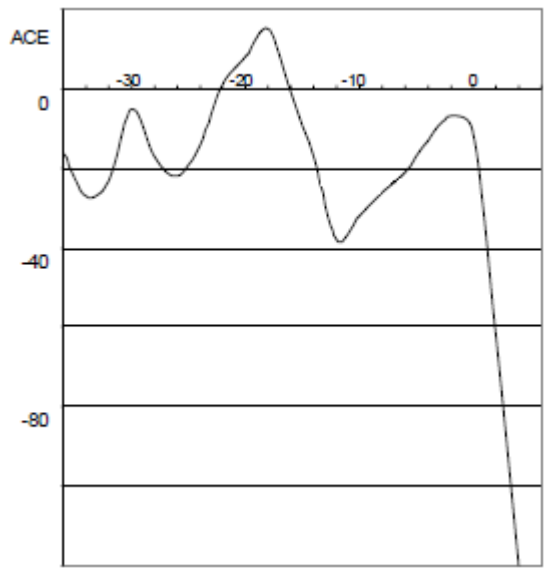
MW_{LOSS} is the MW size of the disturbance as measured at the beginning of the event. It is the size of the resource or demand loss, not the ACE deflection,

ACE_A is the pre-disturbance ACE,

ACE_M is the value of ACE representing the point of greatest recovery from the disturbance measured within the fifteen minutes following the start of the disturbance event. A BA or RSG may, at their discretion, set $ACE_M = ACE_{15\ min}$.

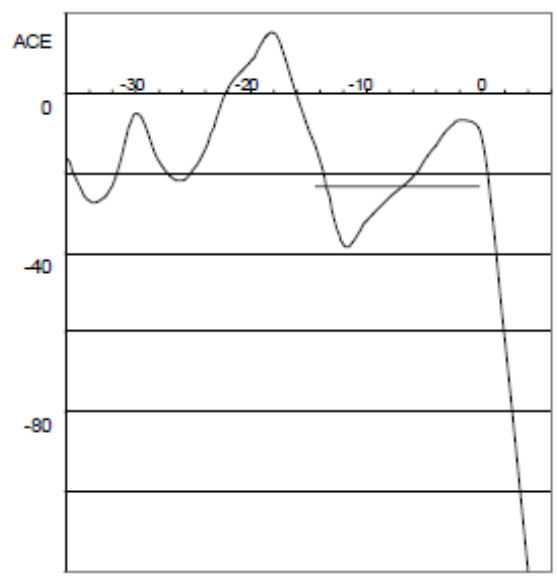
a. **Determination of MW_{LOSS}.**

Record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.



b. **Determination of ACE_A.**

Base the value for ACE_A on the average ACE over the period just prior to the start of the disturbance. Average over a period between 10 and 60 seconds prior and include at least 4 scans of ACE. In the illustration to the right, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the disturbance with a result of ACE_A= -25 MW.



c. **Determination of ACE_M.**

ACE_M is the value of ACE representing the point of greatest recovery from the disturbance measured within fifteen minutes following the start of the disturbance. It is negative for typical generation loss disturbances where zero is not reached within the recovery interval. At the discretion of the BA or of the RSG, compliance may be based on the ACE measured fifteen minutes following the start of the disturbance, i.e., $ACE_M = ACE_{15\ min}$.

Figure 1 demonstrates compliance evaluation during a disturbance condition (Disturbance Control Standard). Note the pattern of the disturbance condition, which began at 0110, the time at which ACE deflection exceeds this entity's disturbance reporting threshold of 50 MW. During this disturbance, the Disturbance Control Standard was violated because ACE was not restored to its pre-contingency level until 0127 (a 17-minute interval which violates the Disturbance Control Standard).

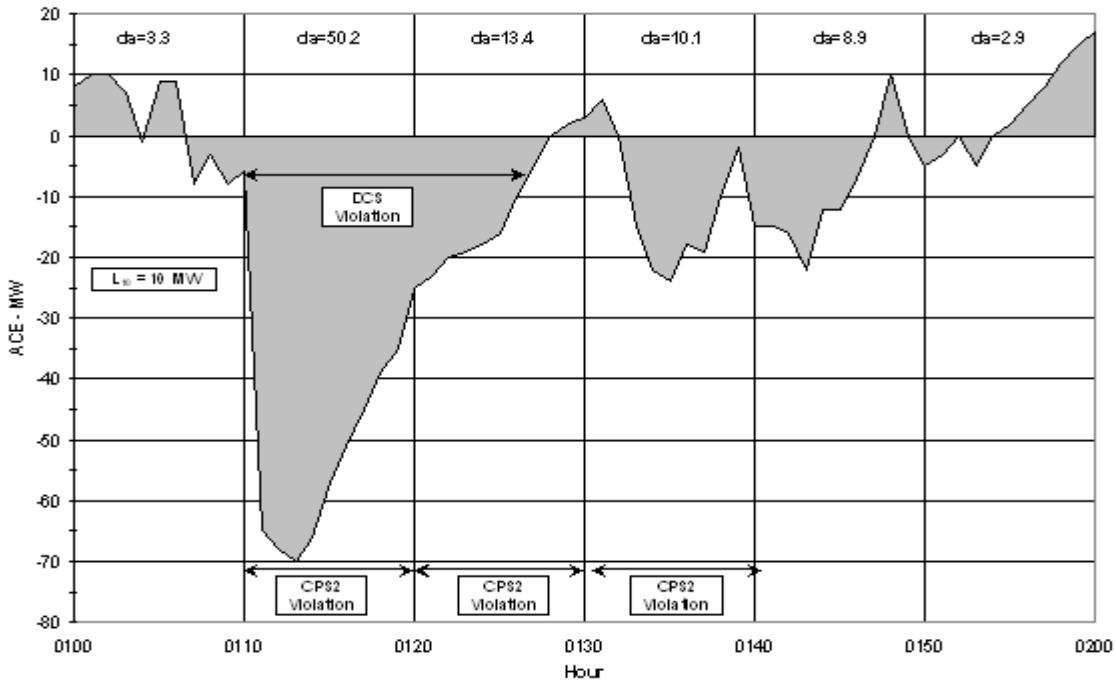


Figure 1 — CPS2-L_{10} Compliance & Disturbance Control Standard, 2 Disturbance Examples

Reporting

Each BA or RSG is to report its Disturbance Control Standard compliance quarterly. The completed Disturbance Control Standard survey is to be supplied to NERC by the 20th day following the end of the respective quarter. Where RSGs exist, the Regional Reliability Council is to decide either to report these on a BA basis or on an RSG basis. If an RSG has dynamic membership or allocates reserves dynamically, then the Region converts the disturbance reporting for the RSG to a BA basis before reporting to NERC. If a BA basis is selected, each BA reports the RSG's performance only for disturbances occurring in their area.

- Reportable Disturbance
  The definition of reportable disturbance magnitude is to be provided to NERC by the respective Regional Reliability Councils. The definition is to include events that are greater than or equal to 80% of a BA's or RSG's most severe single contingency. The definition of a reportable disturbance should be specified in the operating Policy adopted by each Regional Reliability Council. This definition may not be retroactively adjusted in response to observed performance.

a. Most Severe Single Contingency. A BA's most severe single contingency is defined as the magnitude of the largest single credible event that would cause the greatest change in the BA's ACE, or as defined by the respective Regional Council. It is not necessarily a single loss; it could be an entire generating station, or a loss from transmission facility or facilities contingency.

b. Excludable Disturbances and Average Percent Recovery. The BA or RSG is to report both the number of reportable disturbances that occur in the given quarter, and the average percent recovery for that quarter. The report should also indicate excludable disturbances that occurred in the quarter and the average percent recovery for those excluded events.

c. Excludable Disturbance. An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.

d. Average Percent Recovery. The average percent recovery is the arithmetic average of all the calculated Ri from reportable disturbances during the given quarter. Average percent recovery is similarly calculated for excludable disturbances. (See calculation of Ri below).

e. Contingency Reserve Adjustment Factor (CRAF). The quarterly Contingency Reserve Adjustment factor is to include only those reportable disturbances with magnitudes less than or equal to the magnitude of the respective BA's most severe single contingency.

CRAF is defined as follows:

when $n_{Quarter} \geq 0$, then

$$CRAF_{Quarter} = 200 - \left[\frac{\sum R_i}{n_{Quarter}} \right]$$

when $n_{Quarter} = 0$, then $CRA_{Quarter} = 100$

where $n_{Quarter}$ is the number of reportable disturbances experienced during the reporting quarter.
i = reportable disturbances.

R_i is defined in section C.2.

Calculation Precision
The Adjustment Factor is to be rounded off to two decimal places.

Exemptions
Requests for exemptions for single events that cause multiple reportable disturbances (e.g. hurricanes, earthquakes, islanding, etc.) is to be submitted to the NERC Director of Compliance. Until the exemption is approved or denied, the BA or RSG is to consider the request denied.

Contingency Reserve Adjustment Period

BAs are to revise their respective Contingency Reserve Requirement by their computed Contingency Reserve Adjustment factor. The adjustments will be effective starting one month following the end of the reported quarter and remain in effect for three months.

Report Filing

Each BA or RSG is to report its Disturbance Control Standard compliance quarterly, by the 10th working day following the end of the quarter, on Form DCS "NERC Disturbance Control Standard Survey."

a. Mail a copy of the completed Form DCS to the NERC staff.

b. NERC staff will combine the Regional reports into a single summary report and make copies available to each Resources Subcommittee member and others with a legitimate need to know.

Revision History			
Version	Date	Action	Change Tracking

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Flowgate Administration Reference Document (Version 4)

Reference Document Subsections

A. General
B. Guidelines for Permanent Flowgates
C. Flowgate Administration

A. General

Purpose

The Flowgate Administration Reference Document explains how RELIABILITY COORDINATORS can add, modify, and remove flowgates from the Interchange Distribution Calculator (IDC). The procedures that follow in this document:

- Ensure that Reliability Coordinators have the flowgate data they need to manage system reliability.
- Ensure that market participants receive timely information about flowgate changes they need to assess impacts on Interchange Transactions.
- Address administrative authorities, criteria, and processes for:
  - Adding and deleting "permanent" Reliability Flowgates.
  - Modifying Reliability Flowgates in the Book of Flowgates.
  - Defining "temporary" Reliability Flowgates.
  - Expiring "temporary" Reliability Flowgates.
  - Adding "temporary" Reliability Flowgates to the Book of Flowgates.
  - Modifying Informational Flowgates.

Terms

Flowgate. A single transmission element, or group of transmission elements, intended to model MW flow impact relating to transmission limitations and transmission service usage. Within the IDC, Transfer Distribution Factors (see PTDFs and OTDFs as defined below) are calculated to approximate MW flow impact on the flowgate caused by point-to-point power transfers.

Flowgate Categories:

Temporary Flowgate. A flowgate created by a RELIABILITY COORDINATOR within the IDC to monitor or mitigate a Constraint for which a PERMANENT FLOWGATE has not been

identified. TEMPORARY FLOWGATES expire either at the time of the next model update, by default, or on the End Date and Time entered in the IDC, not to exceed ninety days, by the RELIABILITY COORDINATOR who created the TEMPORARY FLOWATE.

Permanent Flowgate.
A flowgate approved by the Reliability Coordinator Working Group and listed in the Book of Flowgates. PERMANENT FLOWGATES remain in the IDC unless removed from the Book of Flowgates and deleted from the IDC.

Flowgate Types: A flowgate may be classified as one or more of the following types

Informational Flowgate Type: A flowgate the RELIABILITY COORDINATOR can establish for monitoring purposes only. An INFORMATIONAL FLOWGATE does not qualify for Transmission Loading Relief (TLR) usage and should be reviewed periodically.

Reliability PTDF Flowgate Type: A RELIABILITY PTDF FLOWGATE is represented by the PTDF of its defined transmission element(s). The defined transmission element(s) can be the monitored element(s) or the contingent element(s). This type of flowgate qualifies for TLR usage under NERC reliability standard IRO-006, "Reliability Coordination — Transmission Loading Relief."

Reliability OTDF Flowgate Type: A RELIABILITY OTDF FLOWGATE is another type of Reliability Flowgate. It is represented by the OTDF on the Monitored Element(s) with the simulated outage of the critical contingency. This type of flowgate also qualifies for TLR usage under NERC reliability standard IRO-006.

Benchmark Flowgate Type: A Benchmark Flowgate is a type identified by the DFWG for internal use by the Interchange Distribution Calculator (IDC) as a quality assurance measure. It is used in monitoring differences in calculated Transfer Distribution Factors (TDFs) by the IDC. A separate column in the Book of Flowgates (Flowgates page) identifies Benchmark Flowgates.

Responsibilities and Authorities

The **Operating Reliability Subcommittee (ORS)** is responsible for:

- Reviewing all changes to the Book of Flowgates at each of its regularly scheduled meetings.
- Resolving disputes resulting from the implementation of Section B, "Guidelines for Permanent Flowgates," or Section C, "Flowgate Administration," in this reference document.

The **Reliability Coordinator Working Group (RCWG)** is responsible for:

- Authorizing all changes to the Book of Flowgates on a monthly basis.
- Providing semi-annual reports on flowgate changes to the ORS.

Individual **RELIABILITY COORDINATORS** are responsible for:

- Authorizing the use of TEMPORARY FLOWGATES.
- Modeling TEMPORARY FLOWGATES within the IDC.
- Recommending conversion of TEMPORARY FLOWGATES to PERMANENT FLOWGATES.
- Reviewing and updating periodically its PERMANENT FLOWGATES.
- Authorizing the removal of PERMANENT FLOWGATES.

The **Distribution Factor Working Group (DFWG)** is responsible for:

- Performing the on-going function of administering the Book of Flowgates under the direction of the RCWG. Administration includes but is not limited to the following:

    1. Tracking the relationship between TEMPORARY FLOWGATES and PERMANENT FLOWGATES for historical purposes.

    2. Reviewing flowgate data, including the transmission element(s), which define PERMANENT FLOWGATES.

    3. Reviewing flowgate data, including the transmission element(s), which define TEMPORARY FLOWGATES used for TLR greater than TLR Level 1.

- Authorizing Book of Flowgates changes that can be unanimously agreed upon. If the DFWG cannot unanimously agree, or if they see reasons for RCWG discussions, then the DFWG will forward the flowgate review to the RCWG with its recommendations.

- Provide quarterly updates to the RCWG on Book of Flowgates changes highlighting key changes in PERMANENT FLOWGATES.

- Modeling the basic set of permanent Book of Flowgates changes as approved by RCWG.

- Maintaining and being the “owner” of the Book of Flowgates.

- Developing a posted flowgate review process for evaluating flowgates.

The **NERC staff** is responsible for:

- Posting the basic set of flowgates on the NERC web site, and posting IDC messages regarding flowgate changes and TEMPORARY FLOWGATE additions. IDC message posting is expected to be an automated process.

B. Guidelines for Permanent Flowgates

A PERMANENT FLOWGATE must meet at least one of the following five requirements to be in the Book of Flowgates:

1. A TLR has been called on the flowgate at least once during the past two years.

2. A TLR greater than TLR Level 1 has been called on the TEMPORARY FLOWGATE at least once during the past two years and the TEMPORARY FLOWGATE was created multiple times during the past two years.

3. The flow on the flowgate has exceeded a reasonably high percentage (i.e. 90%) of its applicable rating or INTERCONNECTED RELIABILITY OPERATING LIMIT (IROL) at least once during the past three years.

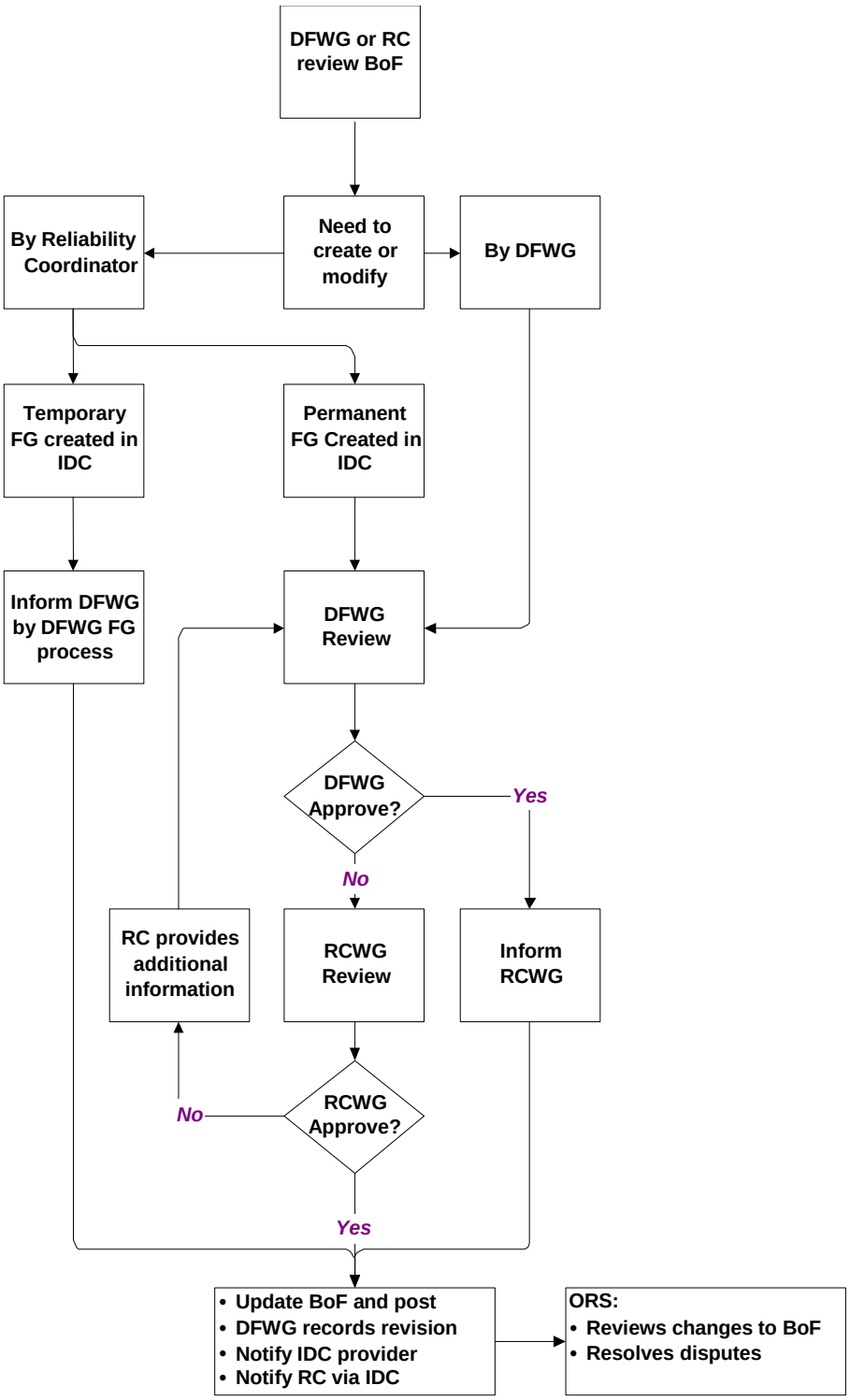
4. The flow on the flowgate is expected to exceed a reasonably high percentage (i.e. 90%) of its applicable rating or IROL in the coming year.

5. The DFWG or RCWG has determined that the flowgate should remain in the Book of Flowgates, or the RELIABILITY COORDINATOR recommends and presents the rationale to the RCWG that a flowgate be included or retained in the Book of Flowgates.

PERMANENT FLOWGATES will not be removed from the Book of Flowgates or the IDC database unless requested by the responsible RELIABILITY COORDINATOR.

C. Flowgate Administration

The Flowgate Administration process is shown in the flowchart below.



Permanent Flowgates

1. The ORS has final approval for the basic set of flowgates taking into account recommendations from the RCWG and DFWG.

2. The DFWG assists in preparing information for RCWG review and maintains records showing when flowgate decisions were made.

3. The responsible RELIABILITY COORDINATOR or its DFWG representative authorizes changes to PERMANENT FLOWGATES through submittal to the DFWG.

4. The DFWG will either unanimously approve flowgates or forward flowgates to the RCWG with recommendations.

5. After the flowgate's approval, the DFWG and IDC service provider will model the flowgate changes.

6. NERC staff will post the basic set of flowgates with a link provided via the NERC web site at crc.nerc.com.

Temporary Flowgates

1. RELIABILITY COORDINATORS, along with the Transmission Providers they represent, will determine the need for TEMPORARY FLOWGATES. TEMPORARY FLOWGATES can be created directly within the IDC and may become available for potential TLR use within 20 minutes to one hour after they are entered into the IDC. TEMPORARY FLOWGATES can be deleted at any time and expire on the End Date and Time, not to exceed ninety days, entered in the IDC by the RELIABILITY COORDINATOR who created the TEMPORARY FLOWGATE . If no End Date and Time is entered for the TEMPORARY FLOWGATE, it will expire when the IDC base case is updated.

2. Information regarding TEMPORARY FLOWGATE additions, modifications, or deletions is communicated to RELIABILITY COORDINATORS via the IDC service provider. Whenever a flowgate is added, deleted, or changed, the IDC service provider will send a message to the DFWG with a copy to a NERC listserver. NERC staff will publicly post the message on the NERC crc.nerc.com web page. Permanent Book of Flowgates changes will be posted separately.

3. TEMPORARY FLOWGATES will expire either at the time of the next model update, by default, or on the End Date and Time entered in the IDC, not to exceed ninety days, by the RELIABILITY COORDINATOR who created the TEMPORARY FLOWATE.. IDC base cases are normally updated on a monthly basis. The IDC model updating process schedule will be posted on the NERC web site as it becomes known.

4. TEMPORARY FLOWGATES, which are used for TLR greater that Level 1, should go through a DFWG review. Individual RELIABILITY COORDINATORS may recommend converting a TEMPORARY FLOWGATE into a PERMANENT FLOWGATE by following Step 3 in the PERMANENT FLOWGATES section above.

Informational Flowgates

1. RELIABILITY COORDINATORS may establish an INFORMATIONAL FLOWGATE to help them monitor power flows over certain interfaces.

2. The RELIABILITY COORDINATOR establishing the INFORMATIONAL FLOWGATE will review the flowgate periodically, and remove the flowgate if no longer needed.

3. INFORMATIONAL FLOWGATES are included in the Book of Flowgates that is posted on the NERC web site.

4. INFORMATIONAL FLOWGATES may be converted to Reliability Flowgates by going through the formal recommendation process.

DFWG Flowgate Review

RELIABILITY COORDINATORS may request the DFWG to review and revise the list of PERMANENT FLOWGATES in accordance with the guidelines detailed in Section B. A standardized approach should be used for reviewing all flowgates. The Book of Flowgates will be kept up to date so that it is consistent with the latest IDC base case. The DFWG will generally not review TEMPORARY FLOWGATES unless:

- They are used for a TLR greater than Level 1.
- A flowgate is repeatedly created as a Temporary Flowgate.
- A request is made to convert a Temporary Flowgate to a Permanent Flowgate.

INFORMATIONAL FLOWGATES are not to be used for TLR. The review for INFORMATIONAL FLOWGATES may differ from that of a Reliability Flowgate. DFWG review of Reliability Flowgates for thermal purposes may differ from the review of Reliability Flowgates used for voltage or dynamic stability purposes.
Flowgate review may require the responsible RELIABILITY COORDINATOR to provide additional flowgate detail as determined by the DFWG.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interchange Reference Guidelines

Version 2

RELIABILITY | ACCOUNTABILITY

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Revision Log

Revision Number	Description of changes
1	• Original document
2	• Added *Table of Contents* section • Added *Revision Log* section • Added *Introduction* section • Added *Interchange Terms* section • Notated all NERC Glossary terms within the document • Added *Interchange Coordinator* section • Updated previous section "The Relationship between Interchange Transactions and Interchange Schedules" section into new *Interchange Fundamentals* section • Added *Implementing Interchange* section • Added *Practical Guide to Interchange Implementation* section including references to the e-Tag specifications and schema • Moved and updated previous "Implementing Interchanges Schedules" section to *Other Interchange Schedule Concepts* subsection • Added *A Note on Dynamic Transfers* section • Added *Consideration for Interchange Involving DC Tie Operator* section • Removed previous section "Interchange Schedules within a Multi-Party Regional Agreement or Transmission Tariff"

Introduction

The Interchange Reference Guidelines address and explain the process to implement Interchange. This document is intended to address the following:

1. Defines Interchange terms,
2. Reviews Interchange Transaction and Interchange Schedule concepts,
3. Reviews the theory of implementing Interchange,
4. Reviews the practical processes used to implement Interchange via e-Tag, and
5. Discusses Dynamic Schedules and DC Ties as related to Interchange.

Interchange Terms

NOTE: In this document, the use of the terms are intended to be identical with the NERC "**Glossary of Terms Used in Reliability Standards"** and the NAESB Business Practice Standard WEQ-000 titled **"Abbreviations, Acronyms, and Definition of Terms".** The definitions listed in the two documents above should prevail if there are any discrepancies. The NERC **"Glossary of Terms Used in Reliability Standards"** is posted at the NERC website in the same location as the Reliability Standards under the link name **"Glossary of Terms"**.

The following terms are used in this document and not defined in standardized industry *Business Practices*:

Market Assessment – The evaluation and verification of the commercial details of *Interchange.*
Market Operator – An entity that is responsible for the implementation of an organized market and submits market adjustments based on market outcomes. A Market Operator must be registered in the Electric Industry Registry (EIR) in order to submit market adjustments.

Wide Area Reliability Tool — This generic term is intended to reflect in a "tool neutral" manner those wide-area reliability assessment tools (such as the *Interchange Distribution Calculator (IDC)* for the Eastern *Interconnection*) acknowledged by NERC as a decision making tool among various reliability entities.

Reliability Assessment – The evaluation and verification of the reliability details of *Interchange*

All terms from the NERC Glossary and defined above are capitalized and italicized in this document. Certain other terms from other locations, such as the e-Tag specification, may be capitalized as well.

Interchange Coordinator

The NERC Functional Model lists the Interchange Coordinator (IC) as the function responsible for communicating *Arranged Interchange* for reliability evaluation and for communicating *Confirmed Interchange* to be implemented between *Balancing Authorities (BAs)*. However, NERC reliability standards refer to the *Interchange Authority (IA)*. These guidelines do not make reference to the *IA* or the IC, but instead refers to the *Sink Balancing Authority* as the responsible entity.

Interchange Fundamentals

The Relationship between Interchange Transactions and Interchange Schedules

Purchasing-Selling Entities (PSEs) and in some instances *BAs* "arrange" *Interchange Transactions* by buying and selling energy and capacity and arranging for *Transmission Services*. A compilation of these arranged *Transactions* are forwarded by the *PSE* to the *Sink Balancing Authority*. Reliability entities assess and "approve" or "deny" *Interchange Transactions* based on reliability criteria, arrangements for *Interconnected Operations Services*, and *Transmission* rights. To "implement" the *Interchange Transaction*, all affected reliability entities incorporate the *Interchange Transaction* into their *Interchange Schedules* as explained on the following pages.

In this example, there are three *Interchange Transactions* (IT1, IT2, and IT3) that result in a number of *Interchange Schedules* between *BAs* A, B, C, and D. (Refer to Figure A on the right and Table 1 below. For simplicity, we are ignoring losses.)

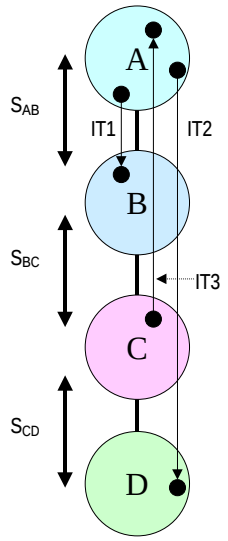

Figure A - Interchange Transactions and Schedules

Interchange Transaction 1 (IT1)

BA A is the *Source Balancing Authority* for *Interchange Transaction* 1 (IT1), and *BA* B is the *Sink Balancing Authority*. To make IT1 occur, *BA* A implements an *Interchange Schedule* with *BA* B ($S_{AB\text{-}IT1}$). In this case, the *Source Balancing Authority* A is the *Sending Balancing Authority*, and the *Sink Balancing Authority* B is the *Receiving Balancing Authority*.

Interchange Transaction 2 (IT2)

BA A is also the *Source Balancing Authority* for *Interchange Transaction* 2 (IT2). *BA* D is the *Sink Balancing Authority* for this *Interchange Transaction*. B and C are *Intermediate Balancing Authorities*. The resulting *Interchange Schedules* are from *Sending Balancing Authority* A to *Receiving Balancing Authority* B ($S_{AB\text{-}IT2}$), *Sending Balancing Authority* B to *Receiving Balancing Authority* C ($S_{BC\text{-}IT2}$), and *Sending Balancing Authority* C to *Receiving Balancing Authority* D ($S_{CD\text{-}IT2}$).

Interchange Transaction 3 (IT3)

BA C is the *Source Balancing Authority* for *Interchange Transaction* 3 (IT3), and *BA* A is the *Sink Balancing Authority*. B is the *Intermediary Balancing Authority*. To make IT3 occur, *Sending Balancing Authority* C implements an *Interchange Schedule* with *Receiving Balancing Authority* B ($S_{CB\text{-}IT3}$), and *Sending Balancing Authority* B implements an *Interchange Schedule* with *Receiving Balancing Authority* A ($S_{BA\text{-}IT3}$).

Net Schedules

BAs A and B can calculate a *Net Interchange Schedule* between these two *BAs* by adding $S_{AB\text{-}IT1}$ and $S_{AB\text{-}IT2}$ and $S_{BA\text{-}IT3}$. *BAs* B and C can calculate a *Net Interchange Schedule* between these two *BAs* by adding $S_{BC\text{-}IT2}$ and $S_{CB\text{-}IT3}$.

The *Net Scheduled Interchange* for A is $S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$. The *Net Scheduled Interchange* for B is $S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3} + S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$.

Balancing Authority	Sink Balancing Authority for:	Source Balancing Authority for:	Sending Balancing Authority for:	Receiving Balancing Authority for:	Net Interchange Schedules
A	IT3	IT1, IT2	IT1, IT2	IT3	$S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$
B	IT1		IT2, IT3	IT1, IT2, IT3	$S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$ $S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$
C		IT3	IT2, IT3	IT2	$S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$ $S_{CD\text{-}IT2}$
D	IT2			IT2	$S_{CD\text{-}IT2}$

Match

Match

Match

Table 1 - Relationship Between Balancing Authorities, Interchange Schedules, and Interchange Transactions

Implementing Interchange

Interchange Transactions are the representation of a *PSE* or *BA* arranging for energy and capacity transfers between different parties. From a real-world perspective, these compiled arrangements are known as a *Request for Interchange (RFI)*. The *RFI* goes through two types of assessment: *Market Assessment* and *Reliability Assessment*.

Prior to the assessment stages, the *PSE* puts together the business arrangements for the *Interchange* with *Transmission Service Providers (TSPs)*, *Generation Providing Entities(GPEs)*, and *Load-Serving Entities (LSEs)* and may obtain preliminary reliability approvals from *BAs*, *TSPs*, and *Reliability Coordinators (RCs)* where required. At this stage, *Agreements* (including *Transmission Service* reservations) are aggregated into a single request. This aggregated information, the *RFI*, is sent to the *BAs*, *PSEs*, and *TSPs* and begins both the *Market Assessment* and *Reliability Assessment*.

During the *Market Assessment* and *Reliability Assessment*, the *RFI* proposed by the *PSE* is evaluated by the approval entities to ensure all the proper information has been given for both commercial and reliability issues and that system conditions allow for approval. Note that the actual *RFI* submission can be assessed and approved or denied by both market and reliability entities.

In both the NERC Standards and NAESB Business Practice Standards, *RFIs* go through several transitions as they are evaluated. Prior to either assessment period, any compiled arrangements are known only as *RFI*. Once the *RFI* is passed to the reliability and market entities to begin evaluation during the *Reliability Assessment* and *Market Assessment*, respectively, then the *RFI* becomes known as *Arranged Interchange*. If approvals are obtained from all entities with approval rights during the *Reliability Assessment* and *Market Assessment*, then the *Arranged Interchange* transitions to *Confirmed Interchange*. *Confirmed Interchange* has obtained all necessary approvals and is ready to be implemented in the *Net Scheduled Interchange* portion of all impacted *BAs*. Once the *Ramp* start time is reached, *Confirmed Interchange* transitions to *Implemented Interchange*. At that point in time, each impacted *BA* will implement the *Implemented Interchange* value into their *Area Control Error (ACE)* equation as part of the *Net Scheduled Interchange*.

The "Normal" Process of Coordinating Interchange

Figure B below shows the normal, reliability-related steps in coordinating *Interchange*. When the *RFI* is submitted to the *Sink Balancing Authority*, it is processed through the *Market Assessment* and *Reliability Assessment*. Once approved during the assessments, the *Sink Balancing Authority* electronically distributes the *Interchange* status, and the *Interchange* information is entered into the *Wide Area Reliability Tool* and into the *ACE* equations of the applicable *BAs*. Note that the NERC INT Standards require coordination of any *Interchange* with any DC tie operating *BA* on the *Scheduling Path*.

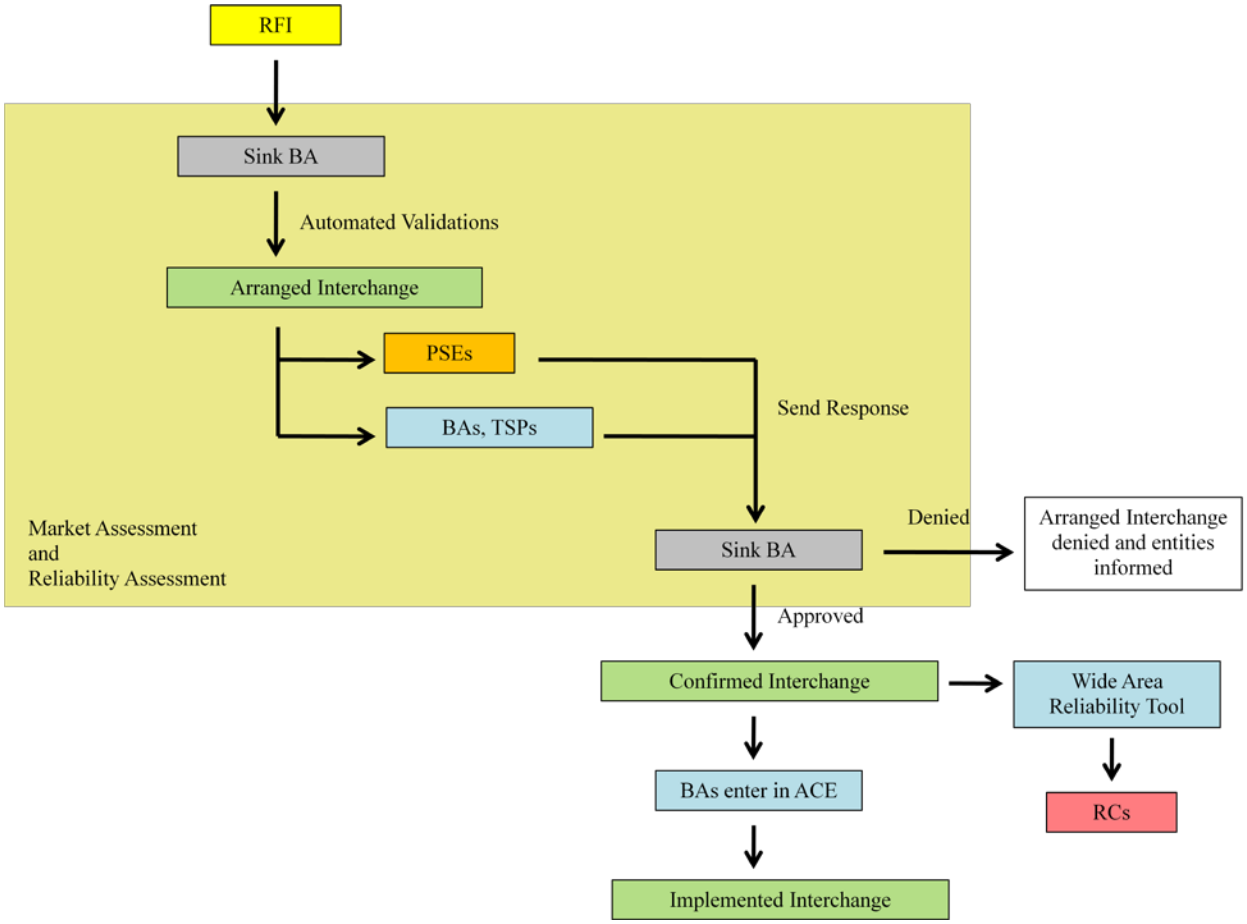

Figure B - Processing on Initial RFI Submission

Interchange Changes for Reliability Reasons

Once *Arranged Interchange* has transitioned to the *Confirmed Interchange* or *Implemented Interchange*, it is entirely possible that the *Interchange* parameters (i.e., MW, *Ramp* start and stop, duration, etc.) may need to change for reliability reasons. The change to *Confirmed Interchange* or *Implemented Interchange* does not eliminate the necessity for coordination. While Figure B shows the coordination that takes place when an *RFI* is initially submitted, Figure C shows coordination steps to effect a change to *Confirmed Interchange* or *Implemented Interchange*.

Interchange created to address an actual or anticipated reliability-related risk or as part of an energy sharing *Agreement* is implemented first without submitting an *RFI* and then follows the submission and transition steps shown in Figure B. *Interchange* modified to address an actual or anticipated reliability-related risk, known as *Reliability Adjustment RFI*, is implemented first and then follows the submission and transition steps shown in Figure C. Note that when submitting *Reliability Adjustment RFI*, only a *Reliability Assessment* occurs since approval rights are only granted to the *Source Balancing Authority* and *Sink Balancing Authority*.

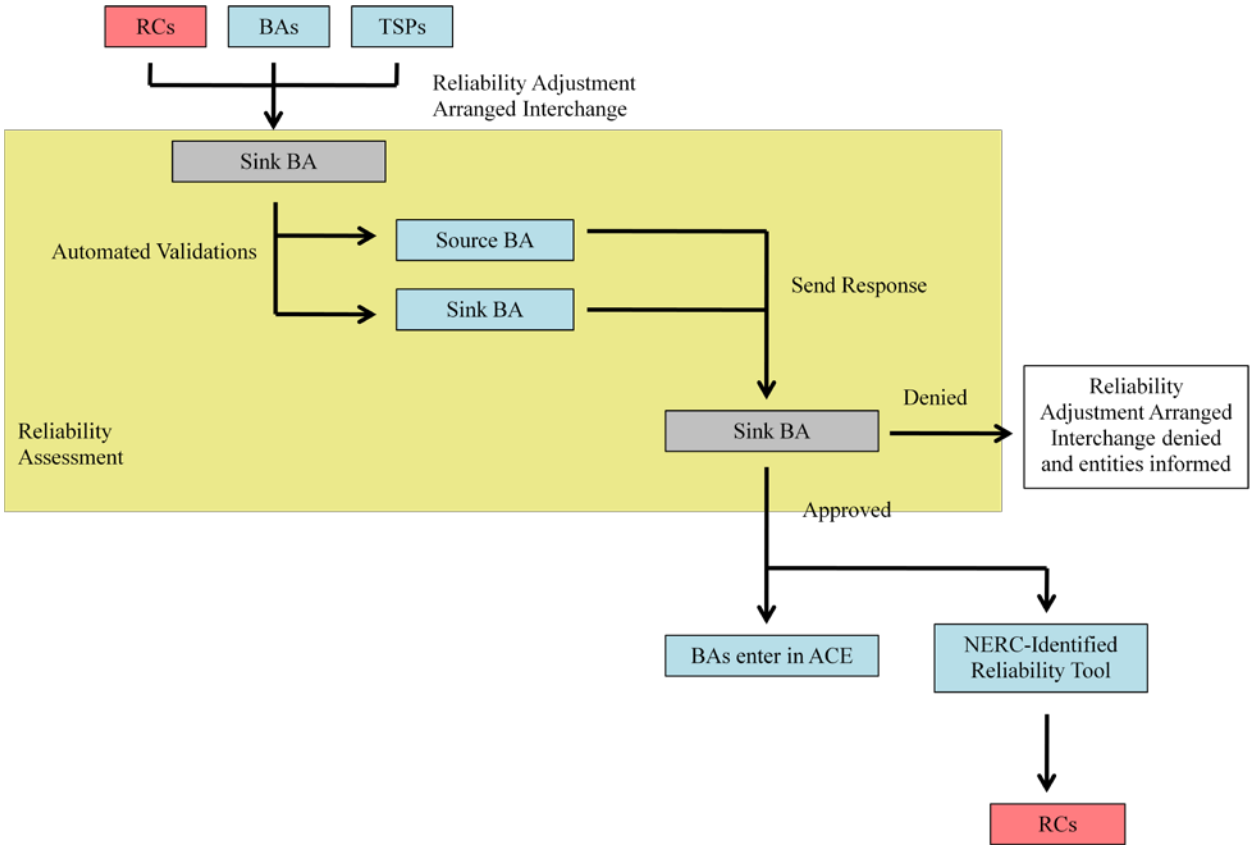

Figure C – Processing of Reliability Adjustment RFI Request

Interchange Changes for Market Reasons

Figure D shows a change (e.g., cancel, increase MW, decrease MW, change *Ramp* or duration info, etc.) initiated by the *PSE*, *BA*, or *Market Operator* for non-reliability reasons once the *Arranged Interchange* has transitioned to *Confirmed Interchange* or *Implemented Interchange*. In this case, the *Confirmed Interchange* or *Implemented Interchange* will undergo the same *Market Assessment* and *Reliability Assessment* as performed when submitting the initial *RFI*. Subsequent steps also follow the same process.

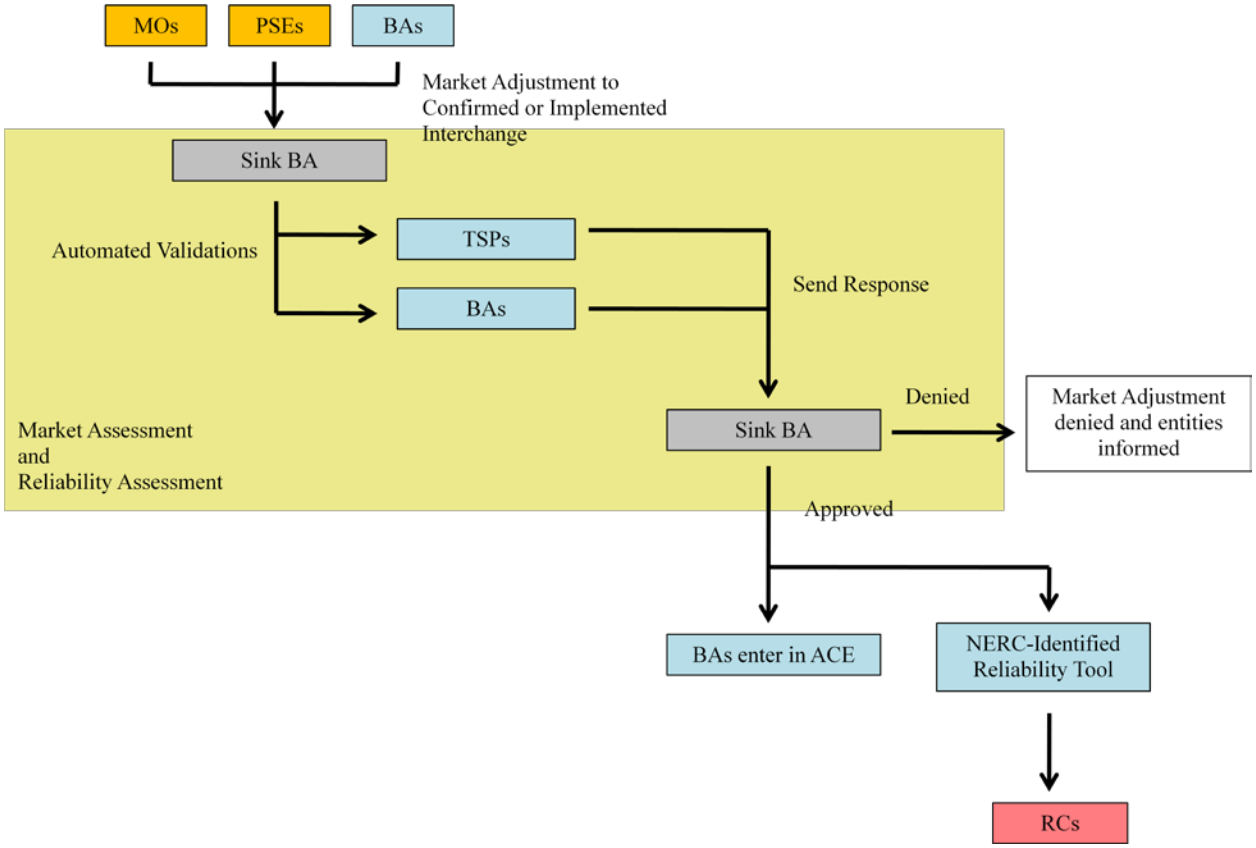

Figure D – Processing of Market Adjustment Request

Practical Guide to Interchange Implementation

The previous sections of this document detail some of the concept behind accomplishing *Interchange*. The first section discussed *Interchange* in terms of how it is transferred between different entities. The second section discussed the way *Interchange* is processed from a theoretical perspective and using terms that are not used during the daily processing of *Interchange*. This section will describe how *Interchange* is practically accomplished on a daily basis.

Interchange is a coordinated process. This process involves arranging for transferring power from a source to a sink point and arranging for the *Transmission* rights across all impacted entities. As this practice grew in volume, the industry moved to adopt technology that would facilitate the business and allow *RCs* to manage *Transmission* congestion. The systems that facilitate the business are based on the e-Tag specifications and schema. Systems implementing the e-Tag specifications allow for entities involved in *Interchange* to assemble an *RFI* into an e-Tag and then send it out for the required approvals before implementation. Any entity that has registered a Tag Agent Service in the EIR can assemble and submit an e-Tag. Typically an entity related to the *Sink Balancing Authority* is responsible for gathering the power deals and *Transmission* rights for submission.

The e-Tag Specifications and Schema are maintained by NAESB and assist in providing the processes required by the NERC and NAESB standards related to *Interchange*. The Joint Electric Scheduling Subcommittee has the primary obligation of monitoring and modifying the e-Tag Specifications and Schema and also has reporting obligations to both the NAESB Executive Committee and the NERC Interchange Subcommittee.

A Note on Wide Area Reliability Tools

In order to maintain reliability, *Interchange* must be coordinated with several entities other than those involved in the transaction. One type of monitoring is accomplished by *Wide Area Reliability Tools*; examples of such tools include the IDC in the Eastern *Interconnection* and webSAS in the Western *Interconnection*. These tools are used for managing congestion when *RCs* (Eastern *Interconnection*) or *BAs* (Western *Interconnection*) issue adjustments to *Interchange* to relieve congested paths in real-time, Each *Wide Area Reliability Tool* has a specific set of rules on how *Interchange* is adjusted.

Functions Detailed in the e-Tag Specifications

The e-Tag Specifications and Schema discuss the practices and technical details needed in the systems that drive e-Tag. Systems implementing the e-Tag specifications are based on transferring data over the Internet to gather and distribute approvals. Most entities implement the e-Tag specifications by contracting with vendors that have developed these systems. The e-Tag Specifications details three main functions that are needed, and all three functions are accomplished by most vendors with their software:

1. Tag Agent - Software component used to generate and submit new e-Tags, Corrections, and Profile Changes to an Authority and to receive State information for these requests.

2. Tag Approval - Software component used to indicate individual approval entity responses when requested by Authority Service as well as submit Profile Changes.
3. Tag Authority - Software component that receives Agent and Approval Requests and Responses and forwards them to the appropriate Approval Services. Also maintains master copy of an e-Tag (all associated Requests), the Composite State of the e-Tag, etc. and responds to queries regarding the e-Tags in its possession.

These different functions ensure that e-Tag submission, approval, and coordination are all handled properly.

Parts of an e-Tag

An e-Tag has several required components in order to be valid. Without these components, the necessary information would not be conveyed to the approving entities. Most software has checks in place to ensure the proper information is supplied. The required parts of an e-Tag include:

1. e-Tag ID – Each e-Tag has a unique e-Tag identifier based on four key attributes:
   a. Source Balancing Authority Code
   b. PSE Code (Tag Author PSE)
   c. Unique transaction identifier
   d. Sink Balancing Authority Code

   The codes specified above for *BAs* and *PSEs* come from the EIR which will be detailed below.
2. Transaction Types – There are several variations in the transaction type that can be chosen for an e-Tag. Transaction types assist in noting the purpose and implementation of a particular e-Tag. Specific *Transmission* tariffs and *Business Practices* should be referenced to determine which of the following transaction types should be selected. e-Tag recognizes the following transaction types:
   a. Normal: These are the normal energy *Schedules* and should represent the largest number of e-Tags. They will include *Schedules* that use *Point to Point Transmission Service*, *Network Integration Transmission Service*, or grand-fathered service under a regional tariff.
   b. Dynamic: A *Dynamic Schedule* is scheduled using an expected value but the actual energy transfer is determined in *Real-time* by separate communications external to the e-Tag system. Also included in this type will be regulation energy *Schedules* and energy imbalance *Schedules*. The e-Tag should contain the expected average energy in the energy profile and contain the maximum expected energy in the Transmission Allocation. Dynamic e-Tags may be adjusted by the *Source Balancing Authority*, *Sink Balancing Authority*, or e-Tag author up to 168 hours in the past using a market adjust to set the actual *Interchange Schedule* value. For additional information related to implementation of *Dynamic Schedules,* please see the Dynamic Transfer Reference Guidelines.

c. Emergency: *Emergency Schedules*, including reserve sharing, *Spinning Reserve*, and supplemental reserve may be scheduled as *Emergency Schedule* Type. For additional detail of when to use Emergency type, see the NERC Glossary of Terms for *Emergency RFI* as well as *Emergency* and *Energy Emergency.*

d. Loss Supply: Loss Supply type is used for customers to self-supply losses. This type is used to differentiate between a loss *Schedule* and a normal *Schedule*. Some tariffs presently require that *Schedules* for losses require different treatment than *Schedules* for the associated energy.

e. Capacity: Capacity type is typically used for entities to import *Operating Reserves* from outside their *Reserve Sharing Group* but may also be used to arrange for purchases or sales of *Spinning Reserve* and supplemental reserve between other entities. This type of e-Tag may be activated upon contingency with zero *Ramp* durations.

f. Pseudo-Tie: A *Dynamic Transfer* implemented as a *Pseudo-Tie* rather than a *Dynamic Schedule*. This type is used in the same way as a Dynamic e-Tag. These e-Tags may be adjusted in the same manner as Dynamic transaction type e-Tags. For additional information related to implementation of *Pseudo Ties,* please see the Dynamic Transfer Reference Guidelines.

g. Recallable: A WECC-only transaction type typically used for "interruptible" or "non-firm" transactions. Adjustments to this transaction type only require *Source Balancing Authority* & *Sink Balancing Authority* approval..

3. Market Segments – Each e-Tag has a section to identify those portions of the path that are associated with the tracking of title and responsibility. Market Segments contain information that describes the market information, such as the identity of the market participant, the firmness of energy the market participant is delivering, and the physical segments the entity is responsible for providing. Market Segments must be listed in order from the *PSE* responsible for generation to the *PSE* responsible for *Load*. There will only be one market segment for generation and one segment for *Load*, but there can be multiple intermediate market segments. Market Segments can describe the responsibility for scheduling actual power delivery, or it can describe non-physical title transfers. These are seen when a market participant takes financial possession for the energy commodity but does not physically move that energy before transferring possession to another financially responsible party. When this occurs, the market segment will not contain any physical segments.

4. Physical Segments – e-Tags also have a section to represent those portions of the path that are physical in nature and represent a movement of energy. There are three types of Physical Segment:

   a. Generation - Generation Segments contain information that describes a generation resource, such as the location of the generation, the firmness of the energy supplied by the resource, and contract references that identify the resource commitment.

b. Transmission – Transmission Segments contain identification that describes a *Transmission Service*, such as the identity of the provider, the *Point of Receipt (POR)* and *Point of Delivery (POD)* of the service, the firmness of the service, simple loss information, and contract references that identify the service commitment.
Load - Load Segments contain information that describes a *Load*, such as the location of the *Load*, the interruptability of the *Load*, and contract references that identify the *Load* obligation. All definitions for information in the segments above must be valid in the EIR which will be described below. Physical Segments must be listed in order from Generation to *Load*. Generation Segments must always be listed first, while Load Segments must be listed last. e-Tags may only have one Generation Segment and one Load Segment. All physical segments must reference a parent market segment, identifying the market entity responsible for the physical segment. These references must also be in an order that matches that described by the market segments. An optional field in the Physical Segments is Scheduling Entities. Many *TSPs* require that e-Tags illustrate not only the contractual relationship between the *TSP* and the *Transmission Customer* but also the internal scheduling information to implement the *Transmission Service* sold under their *TSP's Transmission* tariff. To this end, Scheduling Entities may be defined for a particular Transmission segment.

5. Profile Set – The Profile Sets, commonly referred to as the Energy Profile, section of an e-Tag defines the level at which transactions should run as well as the factors that set those levels. Profiles are specified as a series of time-ordered segments of duration associated with a particular profile. Profiles may optionally contain *Ramp* duration (in minutes) associated with both start time and stop time. The *Ramp* stop time is not needed (and is ignored) in any profile except for the last profile. The *Ramp* duration specifies the number of minutes over which the generator will change from the previous block level to the current block level. *Interchange Schedule* ramping is executed between *BAs* using straddle *Ramp* methods as defined below in "Other Interchange Schedule Concepts".. The *Ramp* duration exists in the e-Tag in order to provide a vehicle by which *Ramp* duration may be exchanged between entities. The Profile Set of an e-Tag is influenced by two different profiles:

   a. Market Limit - The Market Limit defines the level at which the e-Tag author wishes the transaction to run. This level can be used to specify an initial value for a *Dynamic Schedule* as well as a simple level at which the transaction is to be run.

   b. Reliability Limit – The Reliability Limit defines the maximum allowable level at which a transaction may run when that transaction has been identified by a *RC* or other reliability entity as being limited by some *Constrained Facility*. This limit is typically used to indicate *Curtailments*.

   The lower of the most recent approved Market Limit and most recent approved Reliability Limit sets the Current Level on an e-Tag. The Current Level contains the level at which the transaction should be running based on all approved Requests processed by the Authority.

6. Transmission Allocation - Transmission Allocations are a type of e-Tag profile set that defines the way in which market participants will fill their capacity commitments with *Transmission Service* reservations. Transmission Allocations specify a particular reservation, the provider associated with the reservation, and profiles associated with that reservation that describe how the reservation should be consumed. Transmission Allocations must always be associated with Transmission Physical Segments; association with other segments (such as Generation or Load) is not allowed. The Maximum Reservation Capacity associated with each physicalsegment should be greater than or equal to the energy profile. The Transmission Allocation for all Transmission segments must be greater than or equal to the minimum of the *POR* profile and *POD* profile for that segment. One or more *Transmission Service* reservations may be utilized together in what is known as stacking. There are two types of stacking:

   a. Vertical Stacking – A market participant may have two or more *Transmission Service* reservations flowing from the same source to the same sink for the same time period. In this case, Vertical Stacking can be used to tag a Profile Set equal to the combined capacity of the two *Transmission Service* reservations. For example, an e-Tag author can use two 50 MW *Transmission Service* reservations on the same e-Tag to cover 100 MW on the Energy Profile. Figure E shows an example of how Vertical Stacking appears on an e-Tag.

Start	Stop	Energy Profile	Transmission Allocation	
Time	Time	MW	Reservation 1	Reservation 2
12:00	13:00	100	50	50

Figure E – Vertical Stacking

   b. Horizontal Stacking – A market participant may have two or more reservations flowing from the same source to the same sink for different hours. In this case, Horizontal Stacking can be used to tag a Profile Set for the entire time range as long as the capacity of the *Transmission Service reservation* for each hour is not exceeded. For example, an e-Tag author can use two 100 MW *Transmission Service* reservations in subsequent hours to cover 100 MW on the Energy Profile for both hours. Figure F shows an example of how Horizontal Stacking appears on an e-Tag.

Start	Stop	Energy Profile	Transmission Allocation	
Time	Time	MW	Reservation 1	Reservation 2
12:00	13:00	100	100	
13:00	14:00	100		100

Figure F – Horizontal Stacking

7. Loss Accounting – The Loss Accounting section of an e-Tag specifies the manner in which losses should be accounted for over a specified period of time. Over time, an e-Tag Author may elect to specify different choices for how losses will be provided. Usually each *Transmission Operator* across which an e-Tag flows will have specified transactions which require losses and also usually detail what type of losses are required. The two main types of losses in the industry today are Financial Losses and In-Kind Losses. The type of losses provided is dependent upon each Transmisson Provider's tariff / contract.

A Note on the Electric Industry Registry

Several sections detailing the required parts of an e-Tag make reference to the EIR. The EIR is a database where participants in the e-Tagging process register information involved in the process. This registration includes entity names and codes, such as *PSEs*, *BAs*, and *TSPs*. Other pieces of information that are registered include Source and Sink names used on e-Tags, authorized *PSEs* for specific sources and sinks, and valid products for use on e-Tags. The EIR is managed by NAESB.

E-Tag Approval and Timing Process

Once an e-Tag is submitted by an author, it is distributed by the Tag Authority to the appropriate approval entities. For new e-Tag submissions and modifications to e-Tags made by *PSEs*, the *PSEs*, *BAs*, *TSPs* specified on the e-Tag have approval rights. For e-Tag modifications requested for reliability reasons (*Curtailments* and reloads), only the *Source Balancing Authority* and *Sink Balancing Authority* have approval rights. All reliability entities must provide their approval for an e-Tag or modification to an e-Tag to be implemented.

In order to manage this approval process, the industry has developed guidelines around the timing of submitting and processing the approvals. These timing rules are part of the NERC Interchange Standards as well as the NAESB Wholesale Electric Quadrant Business Practice Standards. There are differences in the timing tables between the Eastern *Interconnection* and ERCOT *Interconnection* versus the Western *Interconnection*. Therefore, two different tables are used to show these timing differences.

Any e-Tag that is submitted or modified "On-Time" as defined in the NERC INT standards timing tables, as well as any modification to an e-Tag submitted for reliability reasons, must be evaluated. All Late or *After the Fact (ATF)* e-Tag submissions should be evaluated as time permits.

Other Interchange Schedule Concepts

1. **Ramp duration**. When the *Sending Balancing Authority* and *Receiving Balancing Authority* implement an e-Tag between each other in their respective *ACE* equations, the *BAs* must begin their generation adjustments at the same time using the same *Ramp* durations. A mismatch of these parameters will cause a *Frequency Error* in the *Interconnection*. The standard *Ramp* for e-Tags in the Eastern and ERCOT *Interconnections* is 10 minutes across the e-Tag start time (straddle), and the standard *Ramp* for e-Tags in the Western *Interconnection* is 20 minutes across the tag start time (straddle). Non-standard *Ramps* may be used as long as all *BAs* involved in the *Transaction* agree to the *Ramp* stated on the e-Tag. Figure G shows standard *Ramps*.

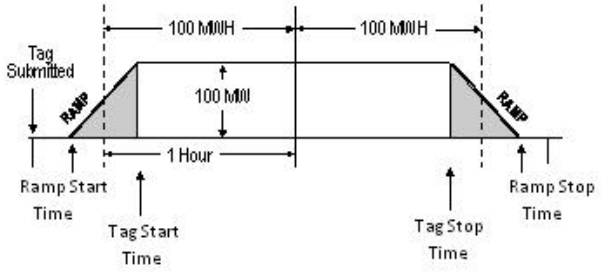

Figure G - Interchange Schedule resulting from 100 MW Interchange Transaction for two hours showing ramps, energy profiles, and energy accounting for each hour.

2. **Starting and ending times**. Most e-Tags generally start and end on the *Clock Hour*. However, *PSEs* may submit e-Tags that start and/or stop at other times beside the *Clock Hour*. *BAs* and *TSPs* should try to accommodate these intra-hour e-Tags. Figure G shows a two hour *Interchange Schedule* starting and stopping at the top of the hour.

3. **Interchange accounting**. All *BAs* must account for their *Interchange Schedules* the same way to enable them to confirm their *Net Interchange Schedules* each day with their *Adjacent Balancing Authorities* as required in NERC BAL Standard **BAL-006 (Inadvertent Interchange)**. *BAs* traditionally use "block" *Interchange Schedule* accounting. This accounting method ignores straddle *Ramp* times and instead uses the *Transaction* start and stop times. This, in effect, moves the energy associated with the starting and ending *Ramps* into their adjacent starting and ending *Clock Hours* of the *Interchange Schedule*. Figure H illustrates the block accounting principle.

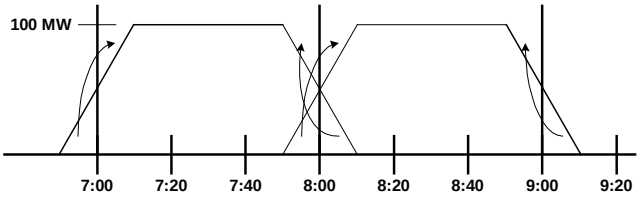

Figure H - Block accounting moves the ramp energy into the adjacent Clock Hours.

A Note on Dynamic Transfers

Dynamic Schedules and *Pseudo-Ties are special Transactions* that rely on time-varying energy tra*nsfers. While e-Tag prov*ides for both transac*tion types, many tagging requi*rements for both types are addressed in regional criteria and *Transmission Operator Business Practices. For more detai*l on these types of *Transactions*, see the NERC Dynamic *Tra*nsfer Guidelines document.

Consideration for Interchange Involving DC Tie Operators

Per the NERC INT Standards, the *Sending Balancing Authorities* and *Receiving Balancing Authorities will co*ordinate *Interchange with an*y DC tie operating *BA*. Note that DC tie operators that are *Intermediate Balancing Authorities* would receive the *Interchange Schedule* information and be subject to the applicable INT standards. The DC Tie operator also would be responsible for notifying the *Sink Balancing Authority* of a DC tie trip and the associated Interchange modification

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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Reference Document

Interconnected Operations Services

Prepared by the
Interconnected Operations Services Subcommittee

Version 1.1 with Proposed Revisions
Incorporating Functional Model Definitions

March 21, 2002

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Section 1. Overview

1.1 Scope and Purpose

This Interconnected Operations Services (IOS) Reference Document was developed by the Interconnected Operations Services Subcommittee in response to a directive from the NERC Operating Committee in November 2000. Version 1.0 of the IOS Reference Document was approved by the Operating Committee in March 2001. Version 1.1 incorporates terms defined in the NERC Functional Model, as approved by the NERC Board of Trustees on June 12, 2001 and as revised on January 20, 2002.

This IOS Reference Document:

- Defines and describes the characteristics of INTERCONNECTED OPERATIONS SERVICES (IOS)
- Describes the necessity of IOS as 'reliability building blocks' provided by generators (and sometimes loads) for the purpose of maintaining BULK ELECTRIC SYSTEM reliability.
- Explains the relationship between OPERATING AUTHORITIES and IOS SUPPLIERS in the provision of IOS.
- Provides sample standards that could be used to define the possible obligations of OPERATING AUTHORITIES and IOS SUPPLIERS in the provision of IOS
- Describes sample methods for performance measurement in the provision of IOS
- Describes sample methods for the certification of IOS RESOURCES.

1.2 Definition of Terms

The definitions of IOS described in this IOS Reference Document are as follows:

REGULATION. The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that responds to automatic controls issued by the BALANCING AUTHORITY.

LOAD FOLLOWING. The provision of generation and load response capability, including capacity, energy, and MANEUVERABILITY, that is dispatched within a scheduling period by the BALANCING AUTHORITY.

CONTINGENCY RESERVE. The provision of capacity deployed by the BALANCING AUTHORITY to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Council contingency requirements. CONTINGENCY RESERVES are composed of CONTINGENCY RESERVE–SPINNING and CONTINGENCY RESERVE–SUPPLEMENTAL.

REACTIVE POWER SUPPLY FROM GENERATION SOURCES. The provision of reactive capacity, reactive energy, and responsiveness from IOS RESOURCES, available to control voltages and support operation of the BULK ELECTRIC SYSTEM.

FREQUENCY RESPONSE. The provision of capacity from IOS RESOURCES that deploys automatically to stabilize frequency following a significant and sustained frequency deviation on the INTERCONNECTION.

SYSTEM BLACK START CAPABILITY. The provision of generating equipment that, following a system

blackout, is able to: 1) start without an outside electrical supply; and 2) energize a defined portion of the transmission system. SYSTEM BLACK START CAPABILITY serves to provide an initial startup supply source for other system capacity as one part of a broader restoration process to re-energize the transmission system.

The six IOS above are a core set of IOS, but are not necessarily an exhaustive list of IOS. Other BULK ELECTRIC SYSTEM reliability services provided by generators or loads could potentially be defined as IOS.

The following related terms are used in this IOS Reference Document:

BALANCING AREA. An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation (and controllable loads) directly to maintain its interchange schedule with other BALANCING AREAS and contributes to frequency regulation of the INTERCONNECTION.

BALANCING AUTHORITY. An entity that: integrates resource plans ahead of time, and maintains load-interchange-generation balance within its metered boundary and supports system frequency in real time.

BULK ELECTRIC SYSTEM. The aggregate of electric generating plants, transmission lines, and related equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission facilities are interconnected.

CONTINGENCY RESERVE – SPINNING. The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation synchronized to the system and fully available to serve load within T_{DCS} minutes of the contingency event; or
- Load fully removable from the system within T_{DCS} minutes of the contingency event.

CONTINGENCY RESERVE – SUPPLEMENTAL. The portion of CONTINGENCY RESERVE provided from IOS RESOURCES consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within T_{DCS} minutes of the contingency event; or
- Load fully removable from the system within T_{DCS} minutes of the contingency event.

DEPLOY. To authorize the present and future status and loading of resources. Variations of the word used in this IOS Reference Document include DEPLOYMENT and DEPLOYED.

DYNAMIC TRANSFER. The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BALANCING AREA into another.

INTERCONNECTED OPERATIONS SERVICE (IOS). A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected BULK ELECTRIC SYSTEMS.

INTERCONNECTION. Any one of the three major electric system networks in North America: Eastern, Western, and ERCOT.

IOS SUPPLIER. An entity that offers to provide, or provides, one or more IOS.

IOS RESOURCE. The physical element(s) of the electric system, which is (are) capable of providing an IOS. Examples of an IOS RESOURCE may include one or more generating units, or a portion thereof, and controllable loads.

LOAD-SERVING ENTITY. An entity that: Secures energy and transmission (and related generation services) to serve the end user.

MANEUVERABILITY. The ability of an IOS RESOURCE to change its real- or reactive-power output over time. MANEUVERABILITY is characterized by the ramp rate (e.g., MW/minute) of the IOS RESOURCE and, for REGULATION, its acceleration rate (e.g., MW/minute^2).

OPERATING AUTHORITY[1]. An entity that:

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission security, and/or emergency preparedness; and
2. Is accountable to NERC and one or more Regional Reliability Councils for complying with NERC and Regional Policies; and
3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

OPERATING RESERVE. That capability above firm system demand required to provide REGULATION, load forecasting error, equipment forced and scheduled outages, and other capacity requirements.

1.3 IOS Are Building Blocks of Reliability

IOS are the elemental 'reliability building blocks' from generation (and sometimes load) necessary to maintain BULK ELECTRIC SYSTEM reliability. These 'reliability building blocks' have historically been provided by integrated utilities, configured as CONTROL AREAS, using internally owned resources. In contrast, in many areas of North American today, the introduction of competitive electricity markets has resulted in restructuring to separate transmission and generation functions, as well as other traditionally integrated functions. Increasingly, some of the entities responsible for reliability of BULK ELECTRIC SYSTEMS do not own all of the resources necessary for reliability but must obtain these resources, in particular generator-provided services, through a market process or through commercial arrangements.

This IOS Reference Document identifies six basic reliability services from generation (and sometimes load) that must be provided, regardless of regulatory environment, market structure, or organizational framework, to ensure BULK ELECTRIC SYSTEM reliability. These functions are the raw materials that OPERATING AUTHORITIES must assemble for deployment on a regional and interconnection basis to achieve BULK ELECTRIC SYSTEM reliability.

The IOS presented in this paper were chosen as such because their unique physical characteristics lend themselves to separate measurement methods and reliability criteria. These IOS can be combined in various ways to support commercial relationships – simply because a function is an IOS should not naturally lead to the conclusion that the marketplace should buy and sell that specific IOS separately.

---

[1] Examples of OPERATING AUTHORITIES, as used in the IOS Reference Document, include the following authorities defined in the NERC Functional Model: RELIABILITY AUTHORITY, BALANCING AUTHORITY, TRANSMISSION OPERATOR, TRANSMISSION SERVICE PROVIDER, and INTERCHANGE AUTHORITY. The IOS Reference Document uses the term OPERATING AUTHORITY when the reference generally applies to more than one functional authority. A specific functional authority is identified when the reference applies only to that authority.

Figure 1 illustrates the relationship between the IOS and reliability objectives. Some of the 'reliability building blocks' from generation are used to achieve generation and load balance, which is fundamental to maintaining a stable BULK ELECTRIC SYSTEM and INTERCONNECTION frequency within defined limits. These generation and demand balancing IOS are REGULATION, LOAD FOLLOWING, and CONTINGENCY RESERVE.

Other IOS are used to maintain a secure transmission network. REACTIVE SUPPLY FROM GENERATION SOURCES and FREQUENCY RESPONSE are examples of IOS for system security.

Finally, IOS can be used for emergency preparedness and restoration, such as the IOS SYSTEM BLACK START CAPABILITY.

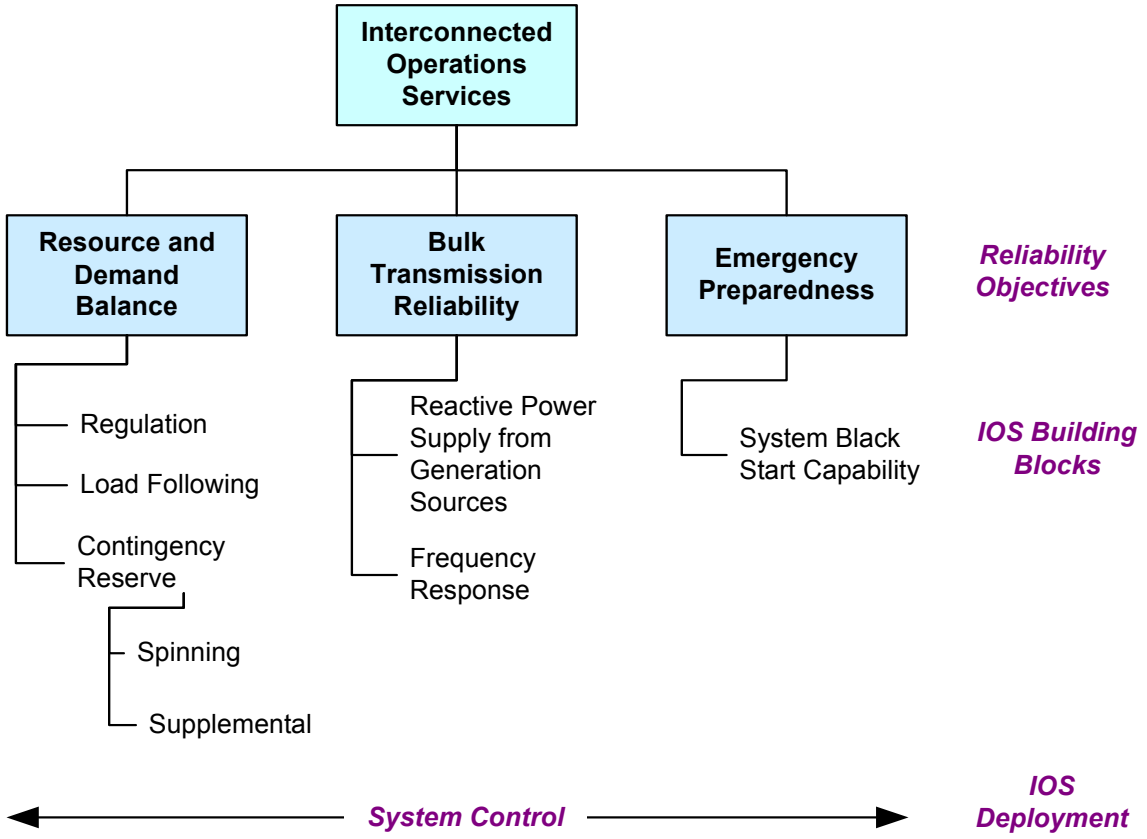

Figure 1 – IOS as Reliability Building Blocks

Section 2. Description of IOS

2.1 Generation and Demand Balancing IOS

BALANCING AUTHORITY Obligations

In their simplest form, generation and demand balancing IOS are capacity and the ability to raise and lower output or demand in response to control signals or instructions under normal and post-contingency conditions. Generators, controllable loads, or storage devices may provide these capabilities. Energy may also be delivered by a resource as a byproduct of providing the balancing capability.

The BALANCING AUTHORITY aggregates and deploys resources providing these services to meet the BALANCING AREA generation and demand balancing obligations, defined by control performance standards in NERC Operating Policy 1. These resources may supply a diverse mix of IOS, since balancing occurs in different time horizons and under both pre- and post-contingency conditions.

Section E of NERC Operating Policy 1 requires that a BALANCING AREA meet the following criteria[2]:

- **Control Performance Standard 1 (CPS1).** Over a year, the average of the clock-minute averages of a BALANCING AREA's ACE divided by –10B (B is the BALANCING AREA frequency bias) times the corresponding clock-minute averages of the INTERCONNECTION'S frequency error shall be less than a specific limit;
- **Control Performance Standard 2 (CPS2).** The ten-minute average ACE must be within a specific limit (L_{10}) at least 90% of the time within each month; and
- **Disturbance Control Standard (DCS).** For reportable disturbances, the ACE must return either to zero or to its pre-disturbance level within a specified disturbance recovery time (defined in IOS Reference Document as T_{DCS}[3] minutes) following the start of a disturbance.

Operating Reserves

Policy 1 also requires a BALANCING AUTHORITY to provide a level of OPERATING RESERVES sufficient to account for such factors as forecasting errors, generation and transmission equipment unavailability, system equipment forced outage rates, maintenance schedules, regulating requirements, and load diversity. Policy 1 states that OPERATING RESERVES consist of REGULATION and CONTINGENCY RESERVES, and that OPERATING RESERVES can be used for the reasons listed above. OPERATING RESERVES may be comprised of: (1) available capacity from resources providing REGULATION and LOAD FOLLOWING services, (2) CONTINGENCY RESERVES, (3) available FREQUENCY RESPONSE capacity, and (4) load-serving reserves or backup supply.

Load-serving reserves are the responsibility of a LOAD-SERVING ENTITY. They are designed to account for errors in forecasting, anticipated and unanticipated generation/resource and transmission outages, and maintenance schedules that impact the delivery of energy to the LOAD-SERVING ENTITY. These reserves support the reliability of individual LOAD-SERVING ENTITIES, rather than the interconnected BULK

[2] NERC is in the process of developing a new standard title "Balance Resources and Demand" that incorporates CPS1, CPS2, and DCS as measures. The IOS Reference Document refers to the standards as they are currently defined in NERC Operating Policy 1.
[3] The disturbance recovery time is defined in the IOS Reference Document as a variable T_{DCS} to recognize that the specified recovery time stated in Policy 1 may change.

ELECTRIC SYSTEMS. As a result, they are not an IOS and are not addressed in this IOS Reference Document.

Overview of Resource and Demand Balancing IOS

Table 1 summarizes the IOS necessary to provide resource and demand balancing services and shows the reliability objective associated with each.

Table 1 – Overview of Resource and Demand Balancing IOS Objectives

IOS		Reliability Objective	
		Normal operating state	**Post-contingency**
REGULATION		Follow minute-to-minute differences between resources and demand.	
LOAD FOLLOWING		Follow resource and demand imbalances occurring within a scheduling period.	
FREQUENCY RESPONSE[4]			Arrest deviation from scheduled frequency.
CONTINGENCY RESERVES	SPINNING		Restore resource and demand balance, usually after a contingency.
	SUPPLEMENTAL		Restore resource and demand balance after a contingency

Figure 2 compares the use and deployment period of the resource and demand balancing IOS.

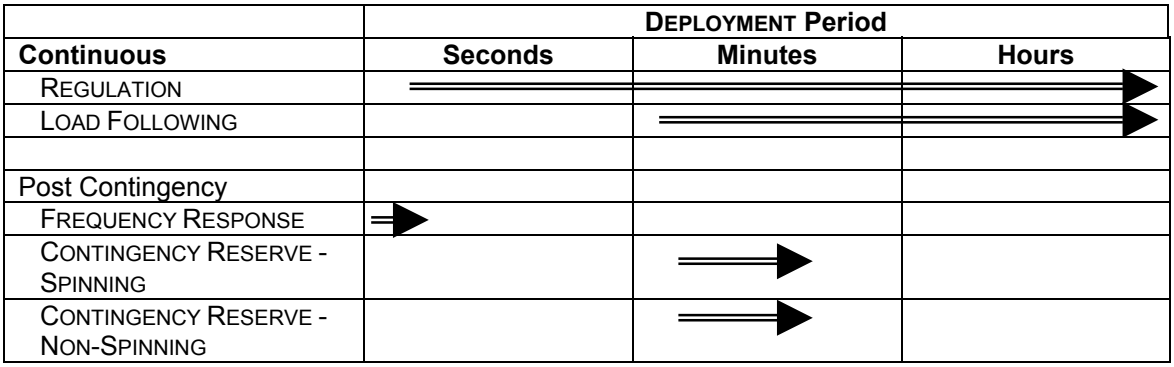

Figure 2 – Deployment Period for Resource and Demand Balancing IOS

Description of REGULATION AND LOAD FOLLOWING

REGULATION and LOAD FOLLOWING require similar capabilities and are addressed together in this IOS Reference Document. A major difference is that LOAD FOLLOWING resources are deployed over a longer

[4]In this IOS Reference Document, FREQUENCY RESPONSE is treated as an INTERCONNECTION security function, rather than a generation and demand balancing function. It is shown in Table 2 and Figure 2 only for the purpose of showing the deployment times relative to those of the resource and demand balancing IOS.

time horizon and over a generally wider range of output than resources providing REGULATION. The LOAD FOLLOWING burden imposed by individual loads tends to be highly correlated while the REGULATION burden tends to be largely uncorrelated.

REGULATION provides for resource and demand balancing in a time frame of minutes. The BALANCING AUTHORITY continuously determines the required changes (up and down) to the real power output of regulating resources to correct ACE to within CPS bounds.

LOAD FOLLOWING addresses longer-term changes in demand within scheduling periods. LOAD FOLLOWING resources, under automatic or manual control, chase (and to an extent anticipate) the longer-term variations within a scheduling period. Figure 3 distinguishes the time horizons of REGULATION AND LOAD FOLLOWING IOS.

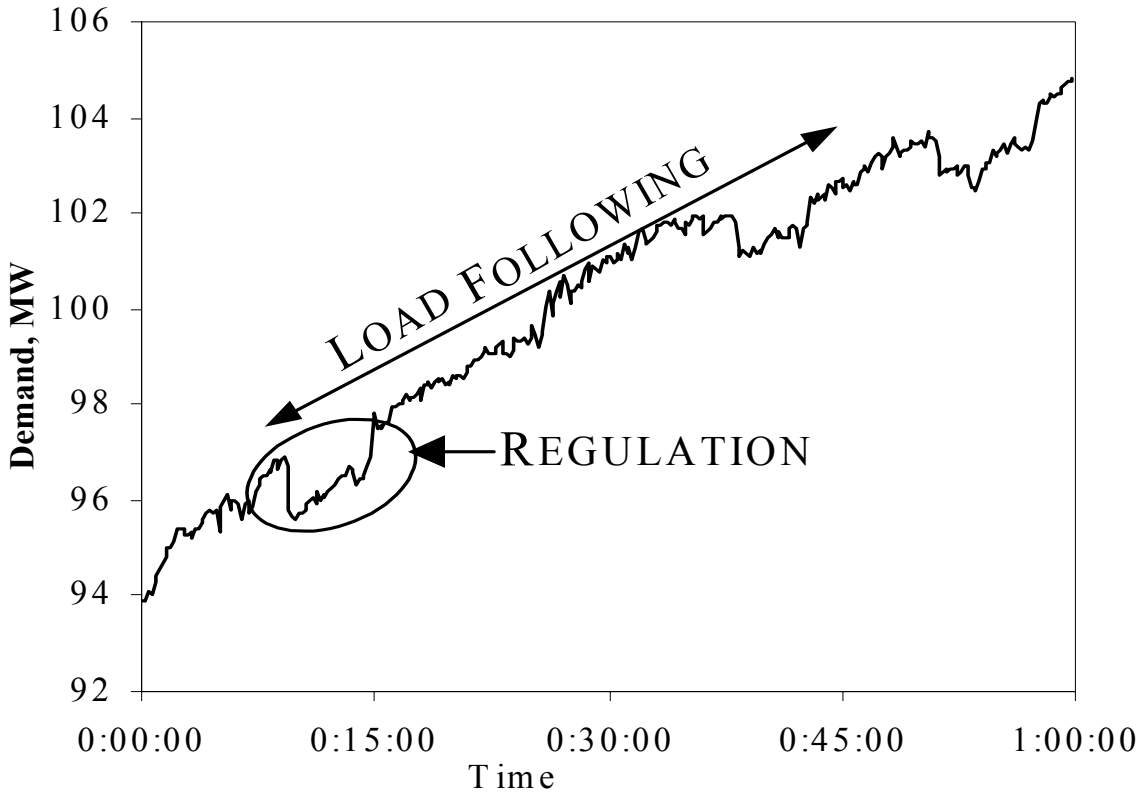

Figure 3 – REGULATION and LOAD FOLLOWING

Description of CONTINGENCY RESERVE

In addition to committing and controlling resources to ensure continuous balance between resources and demand, NERC Policy 1 requires a BALANCING AUTHORITY to return resources and demand to a balanced state (or at least to the same level of imbalance as the pre-contingency state) within ten minutes following a contingency. CONTINGENCY RESERVE provides standby capability to meet this requirement.

Following a contingency, FREQUENCY RESPONSE will immediately begin to arrest the frequency deviation across the INTERCONNECTION. Within the affected BALANCING AREA, resources providing REGULATION will begin to adjust outputs within seconds in response to signals from the BALANCING AREA's AGC. In addition, the BALANCING AUTHORITY may deploy, if necessary, CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL. These reserves are used to restore the pre-contingency resource and demand balance, FREQUENCY RESPONSE capacity, and REGULATION capacity. In all cases, the CONTINGENCY RESERVE must be sufficiently activated so that within T_{DCS} (or less) the pre-contingency resource/demand balance and FREQUENCY RESPONSE capacity are restored. Delivery of these reserves must be sustainable for the minimum reserve deployment period.

The time line below in Figure 4 graphically shows the operating relationship between FREQUENCY RESPONSE, CONTINGENCY RESERVE and an individual LOAD-SERVING ENTITY'S reserve or backup supply.

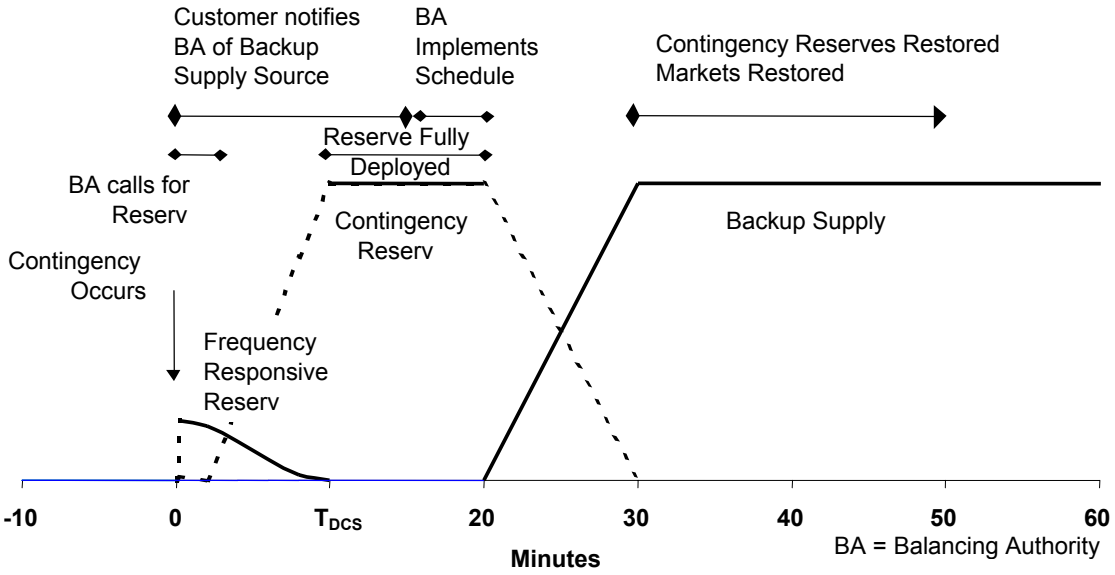

Figure 4 – Operating Reserve Timeline

Coordinated post-contingency operating plans are necessary to ensure BALANCING AUTHORITIES are able to deploy and restore CONTINGENCY RESERVE in a timely manner. These plans must outline the reserve obligations of BALANCING AUTHORITIES, other OPERATING AUTHORITIES, and LOAD-SERVING ENTITIES. These arrangements should delineate when and how schedules will be curtailed, which BALANCING AUTHORITY is responsible to deploy CONTINGENCY RESERVE, and when and how replacement schedules, if any, will be implemented.

Transmission Losses

Although the previous discussion focused on the mismatch between resources and demand due to randomly varying loads as well as control and scheduling errors, the losses associated with use of the transmission system must also be recognized. Real power losses are actually another type of demand and, if not compensated for, can cause a deficiency in reserves and system frequency degradation, thus threatening system reliability.

All electrical flows impact system losses. This includes transmission customer uses, native load uses, parallel flows, and other uses. All scheduled users of the transmission system are responsible for providing losses associated with their use of the system. The BALANCING AUTHORITY is responsible to balance total system demand, including losses.

The difference in real-time between actual system losses and resources scheduled to supply system losses is provided by REGULATION and LOAD FOLLOWING. For this reason, the IOS Reference Document does not treat losses as a separate IOS. Instead losses are handled in the market, through scheduling processes, in accordance with transmission tariffs and contracts. Any differences between scheduled and actual losses are addressed through REGULATION and LOAD FOLLOWING, or possibly through energy imbalance measures, if a transmission customer is delivering energy to compensate for losses.

Energy Imbalance

Energy and scheduling imbalances are ***measures*** of how well a transmission customer is meeting its balancing obligations at a specific point or points on the system. Such imbalances are calculated as the difference between actual and scheduled energy at a point of receipt or point of delivery over a scheduling period.

The provision of resource and demand balancing in a pre-contingency state for a transmission customer is done through the use of scheduled delivery of resources to serve the transmission customer's load, along with the provision of REGULATION and LOAD FOLLOWING.

Although existing transmission tariffs may treat energy imbalance as a service, the IOS Reference Document considers energy imbalance, including scheduling imbalances with generators, as energy mismatch measurements. Energy imbalance is a measure of historical performance averaged over a time period. IOS are *capabilities* that are deployed in the present and future to meet reliability objectives. Both energy imbalance and IOS can be measured, and can have reliability criteria and economic terms. However, energy imbalance only describes past performance, while IOS are services that may be deployed now and in the future for reliability purposes.

2.2 Bulk Electric System Security IOS

System security refers to the ability of BULK ELECTRIC SYSTEMS to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Two fundamental capabilities needed to maintain BULK ELECTRIC SYSTEM security are the ability to[5]:

1. Maintain system voltages within limits to maintain INTERCONNECTION reliability under normal and emergency conditions. This is accomplished by coordinating the following

[5] Refer to Operating Policy 2 B and Planning Policy I D for Control Area standards related to voltage control.

minimum components of transmission system voltage control:

- Load power factor correction;
- Transmission reactive compensation (capacitors, reactors, static var compensators, etc.);
- Generator interconnection requirements with the transmission provider (relay and control, power factor, voltage, etc.);
- OPERATING AUTHORITY coordination; and
- REACTIVE POWER SUPPLY FROM GENERATION SOURCES (IOS)

2. Automatically and rapidly arrest frequency excursions due to contingencies on BULK ELECTRIC SYSTEMS. This capability constitutes the FREQUENCY RESPONSE IOS.

REACTIVE POWER SUPPLY FROM GENERATION SOURCES

REACTIVE POWER SUPPLY FROM GENERATION SOURCES comprises the following essential capabilities from generators (and possibly some loads): reactive capacity, reactive energy, dynamic and fast-acting responsiveness through the provision and operation of an Automatic Voltage Regulator (AVR), and the ability to follow a voltage schedule. REACTIVE POWER SUPPLY FROM GENERATION SOURCES is used by the OPERATING AUTHORITY to maintain system voltages within established limits, under both pre- and post-contingency conditions, and thereby avoid voltage instability or system collapse.

Interconnection Requirements – Reactive

In addition to the use of this generation-based IOS, the OPERATING AUTHORITY maintains transmission security through the coordinated use of static reactive supply devices throughout the system, and may develop and impose reactive criteria on LOAD-SERVING ENTITIES. Requirements for the non-generator components are addressed in NERC, Regional Reliability Council, and local standards and interconnection requirements.

As an example, minimum interconnection requirements include NERC Planning Standard III C S1, which states: "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." The intent is that there be no supplementary excitation control (reactive power or power factor control) that limits emergency reactive power output to less than reactive power capability.

Generator power factor and voltage regulation standards can be a condition of interconnection to satisfy area or local system voltage conditions. Voltage regulating capacity and capabilities that are provided to meet minimum interconnection requirements do not imply that those generators are qualified IOS SUPPLIERS.

FREQUENCY RESPONSE

FREQUENCY RESPONSE is the capability to change, with no manual intervention, an IOS RESOURCE's real power output in direct response to a deviation from scheduled frequency.

The need for FREQUENCY RESPONSE extends beyond the boundaries of a BALANCING AREA to meet the reliability needs of the INTERCONNECTION. Hence it is aligned with a transmission security objective rather than the resource and demand balancing objective. FREQUENCY RESPONSE is not required to meet the BALANCING AREA needs related to DCS. CONTINGENCY RESERVE is used for that purpose.

FREQUENCY RESPONSE is achieved through an immediate governor response to a significant change in INTERCONNECTION frequency. The cumulative effect of the governor response within the INTERCONNECTION provides an INTERCONNECTION-wide response to a frequency deviation (i.e., all BALANCING AREAS will "see" a frequency change and contribute their frequency response in proportion to the frequency change). This governor action arrests the frequency deviation and allows other slower responding control actions to effectively restore system frequency and affected BALANCING AREA's ACE.

2.3 Emergency Preparedness

Emergency preparedness refers to the measures taken to prepare for the rare occasions when all or a major portion of a BULK ELECTRIC SYSTEM or INTERCONNECTION is forced out of service. When this occurs, the capability must exist to restore normal operations as quickly as possible. This is called system restoration. System restoration requires:

- SYSTEM BLACK START CAPABILITY – Generating units that can start themselves without an external electricity source and can then energize transmission lines and restart other generating units;
- Non-black start generating units that can quickly return to service after offsite power has been restored to the station and can then participate in further restoration efforts;
- Transmission system equipment, controls, and communications (including ones that can operate without grid power), and field personnel to monitor and restore the electrical system after a blackout;
- System control equipment and communications (including ones that can operate without grid power); and
- Personnel to plan for and direct the restoration operations after such a blackout.

The IOS Reference Document deals only with the first of these five aspects of system restoration, as it is a critical reliability service that must be provided by generation resources. Other NERC Planning and Operating Standards address other elements of this service. NERC Planning Standard 4A, System Black Start Capability, states that: "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 BLACK START CAPABILITY.

NERC Operating Policy 6 D, Operations Planning – System Restoration, requires: Each OPERATING AUTHORITY and Region shall develop and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of the system. For further reference, see Policy 5 E, Emergency Operations-System Restoration.

Section 3. Sample IOS Standards

3.1 Sample General Requirements

Introduction

Section 3.1 provides a sample of general requirements that may be applicable for all IOS. These sample general requirements establish a framework of responsibilities for:

- Development of IOS specifications and metrics for certification and performance evaluation.
- The provision of IOS, including planning, aggregation, and deployment.
- Monitoring and verification of IOS.

Specific sample standards for each IOS are provided in the remaining parts of Section 3. The sample standards throughout Section 3 are grouped into two main subheadings according to the type of entity to which the standards may apply: OPERATING AUTHORITY or IOS SUPPLIER.

The sample standards in the IOS Reference Document stipulate that the required amounts of each IOS are contingent upon the characteristics of the regional or local BULK ELECTRIC SYSTEMS. Such specific regional or local requirements should be developed through a process that is a) open to and inclusive of all market participants, and b) in accordance with the prevailing regional processes for standards development.

The sample IOS SUPPLIER requirements are intended to apply to all IOS RESOURCES regardless of ownership.

Sample General Requirements – OPERATING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Provision of IOS.** The OPERATING AUTHORITY shall assure sufficient IOS are arranged, provided, and deployed to meet NERC, Regional Reliability Council, and local planning and operating standards.

2. **Specify IOS Requirements.** The OPERATING AUTHORITY shall determine IOS requirements through an open and inclusive process that is consistent with regulatory requirements, is coordinated at a regional level, includes market stakeholders, and allows for dispute resolution. Regional and local IOS requirements include but are not limited to:

2.1. The quantity, response time, duration, location and other criteria for each IOS as necessary to meet NERC, Regional Reliability Council, and local planning and operating standards.

2.2. Written procedures for the arrangement, provision, and deployment of IOS.

2.3. Metering requirements, consistent with established industry practices, for IOS RESOURCES.

2.4. Voice and data communication requirements associated with provision and delivery of IOS.

2.5. Transmission service requirements for delivery of each IOS.

3. **Changing System Conditions.** IOS requirements and procedures shall be adapted as necessary to maintain system reliability in response to current or expected system conditions.

4. **Publication of IOS Requirements.** The OPERATING AUTHORITY shall maintain publicly available documents specifying IOS requirements and procedures.

5. **Performance Verification.** The OPERATING AUTHORITY shall monitor the actual performance of IOS RESOURCES under normal and/or disturbance conditions to verify the IOS RESOURCE meets published performance criteria.

Sample General Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

7. **IOS RESOURCE Capabilities.** An IOS SUPPLIER shall provide IOS RESOURCES which are:

7.1. Able to deliver the stated IOS capabilities to the BULK ELECTRIC SYSTEM.

7.2. Responsive to the instructions and controls of the OPERATING AUTHORITY, as specified for each IOS and consistent with previously agreed upon terms and conditions between the IOS SUPPLIER and OPERATING AUTHORITY.

8. **IOS RESOURCE Certification**. The capabilities of IOS RESOURCES shall be certified according to the defined minimum criteria. (See IOS Reference Document Section 4.3 for certification criteria.)

9. **Metering.** An IOS SUPPLIER shall provide and maintain metering to measure IOS capabilities and performance, as specified by published IOS requirements.

10. **Voice and Data Communications.** An IOS SUPPLIER shall provide and maintain voice and data communications, as specified by published IOS requirements, to enable:

10.1. IOS RESOURCES to respond to the instructions or controls of the OPERATING AUTHORITY.

10.2. OPERATING AUTHORITIES to monitor the capabilities and verify the performance of IOS RESOURCES.

11. **Provision of IOS.** An IOS SUPPLIER shall, as soon as practicable, notify the OPERATING AUTHORITY of any changes in the capability to provide the service or meet stated obligations.

12. **Performance Verification.** Upon request, an IOS SUPPLIER shall provide information to the OPERATING AUTHORITY necessary to verify performance, in accordance with published IOS requirements and procedures. All IOS SUPPLIERS, including OPERATING AUTHORITIES, which are

IOS SUPPLIERS, shall maintain and provide verifiable data for certification purposes.

13. **Concurrent Commitment of IOS RESOURCES.** An IOS SUPPLIER may make concurrent commitments of an IOS RESOURCE's capability to provide IOS (for example providing recallable energy and CONTINGENCY RESERVE – SUPPLEMENTAL), if the following conditions are met:

13.1. The practice is disclosed, in advance, to the OPERATING AUTHORITY(IES) involved; and

13.2. The arrangements do not conflict with meeting the IOS SUPPLIER's obligations, nor the provision requirements of each concurrently committed IOS. For example, the same capacity for CONTINGENCY RESERVE may not be concurrently used for REGULATION.

3.2 Sample REGULATION and LOAD FOLLOWING Requirements

Sample Requirements – BALANCING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The BALANCING AUTHORITY shall determine the IOS requirements for REGULATION and LOAD FOLLOWING in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response capabilities of IOS RESOURCES.

2. **Provision.** The BALANCING AUTHORITY shall assure sufficient REGULATION and LOAD FOLLOWING capabilities are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local planning and operating standards.

3. **Deployment.** The BALANCING AUTHORITY shall direct the current and future loading of the portion of IOS RESOURCES providing REGULATION or LOAD FOLLOWING. Loading refers to the energy delivery of the IOS RESOURCE, within the operating constraints committed by the IOS SUPPLIER.

4. **IOS SUPPLIER Performance Monitoring.** The BALANCING AUTHORITY shall monitor the REGULATION and LOAD FOLLOWING performance of IOS SUPPLIERS. The BALANCING AUTHORITY shall maintain records of IOS SUPPLIER performance and data used to calculate performance.

Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

5. **Declaration of REGULATION Response Capability.** An IOS SUPPLIER that has agreed to provide REGULATION shall declare to the BALANCING AUTHORITY the IOS RESOURCE's:

5.1. Maximum and minimum outputs that define the REGULATION range of the IOS RESOURCE**.**

5.2. MANEUVERABILITY characteristics including ramp up and ramp down limit, minimum time between requests for control changes, and maximum and minimum acceleration.

6. **Declaration of LOAD FOLLOWING Response Capability.** An IOS SUPPLIER providing LOAD FOLLOWING shall declare to the BALANCING AUTHORITY the IOS RESOURCE's:

6.1. Maximum and minimum outputs that define the LOAD FOLLOWING range of the IOS RESOURCE.

6.2. The ramp rate and acceleration of the IOS RESOURCE**.**

6.3. The minimum time period between requests for load changes.

7. **REGULATION Response.** An IOS RESOURCE that is offered to provide REGULATION shall automatically change the real power output in response to the controls supplied by the BALANCING AUTHORITY, subject to the agreed upon REGULATION capabilities of the IOS RESOURCE.

8. **LOAD FOLLOWING Response.** An IOS RESOURCE that is offered to provide LOAD FOLLOWING shall increase or decrease its real power output in response to instructions from the BALANCING AUTHORITY, subject to the agreed upon LOAD FOLLOWING capabilities of the IOS RESOURCE.

9. **Metering and Communication.** An IOS SUPPLIER offering to provide REGULATION or LOAD FOLLOWING shall meet the following minimum metering and communication requirements:

9.1. The IOS RESOURCE shall have a BALANCING AUTHORITY approved data communication service between the IOS RESOURCE control interface and the BALANCING AREA.

9.2. The IOS RESOURCE shall have a BALANCING AUTHORITY approved voice communication service to provide both primary and alternate voice communication between the BALANCING AUTHORITY and the operator controlling the IOS RESOURCE.

9.3. The IOS SUPPLIER shall provide to the BALANCING AUTHORITY real-time telemetry of the real power output of each IOS RESOURCE. The update frequency for REGULATION and LOAD FOLLOWING shall be in accordance with the requirements and guides in Operating Policy 1. The availability and reliability of the telecommunications shall comply with Operating Policy 7.

10. REGULATION and LOAD FOLLOWING IOS RESOURCES Outside of the BALANCING AREA. IOS SUPPLIERS providing REGULATION or LOAD FOLLOWING from IOS RESOURCES located in a BALANCING AREA other than the BALANCING AREA in which the load is physically connected, shall be controlled by a DYNAMIC TRANSFER.

3.3. Sample CONTINGENCY RESERVE Requirements

Sample Requirements – BALANCING Authority

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The BALANCING AUTHORITY shall determine the IOS requirements for CONTINGENCY RESERVE – SPINNING, and CONTINGENCY RESERVE – SUPPLEMENTAL in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response characteristics, allowed overshoot, and the portion of CONTINGENCY RESERVE that must be SPINNING or SUPPLEMENTAL.

2. **Provision.** The BALANCING AUTHORITY shall assure sufficient capabilities for CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local operating requirements.

3. **CONTINGENCY RESERVE Dispersion.** CONTINGENCY RESERVES dispersion shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements.

4. **Deployment of CONTINGENCY RESERVE – SPINNING AND SUPPLEMENTAL.** The BALANCING AUTHORITY shall direct the loading of IOS RESOURCES that provide CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL. The BALANCING AUTHORITY shall ensure deployment capability within the required recovery time from disturbance conditions (T_{DCS}) specified in Operating Policy 1. The BALANCING AUTHORITY shall ensure deployment of CONTINGENCY RESERVE is sustainable for a minimum of 30 minutes following the contingency event.

5. **Verification of Performance.** The BALANCING AUTHORITY shall verify that all IOS RESOURCES requested to provide CONTINGENCY RESERVE – SPINNING, and SUPPLEMENTAL do so according to established performance criteria, including reaching the requested amount of real power output within and for the specified time limits.

6. **Restoration of CONTINGENCY RESERVE.** The BALANCING AUTHORITY shall develop clear operating plans and procedures to assure the timely deployment and restoration of CONTINGENCY RESERVE. These plans and procedures shall specify how CONTINGENCY RESERVE shall be restored, for example, how and when schedules are curtailed, replaced, or initiated.

Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

7. **Declaration of CONTINGENCY RESERVE Capability.** An IOS SUPPLIER that has agreed to provide CONTINGENCY RESERVE shall declare to the BALANCING AUTHORITY the IOS RESOURCE'S capabilities.

8. **IOS RESOURCE Response.** An IOS RESOURCE offered to provide CONTINGENCY RESERVES shall be:

8.1. Responsive to the instructions and/or variable scheduled output supplied by the BALANCING AUTHORITY.

8.2. Continuously synchronized to the system, when providing CONTINGENCY RESERVES – SPINNING SERVICE.

8.3. Available for redeployment after the pre-arranged elapsed time as specified by the IOS SUPPLIER.

9. **Provision of CONTINGENCY RESERVES.** In response to the instructions of the BALANCING AUTHORITY, and subject to the declared capabilities of the IOS RESOURCE, the IOS RESOURCE shall:

9.1. Provide between 100% and the allowed overshoot of the stated amount (MW) of CONTINGENCY RESERVE – SPINNING within (T_{DCS} – X) minutes of a call by the BALANCING AUTHORITY requesting CONTINGENCY RESERVE. X is the number of minutes agreed to in advance by the BALANCING AUTHORITY and IOS SUPPLIER that allows for the BALANCING AUTHORITY to respond to a contingency and call for deployment of CONTINGENCY RESERVE.

9.2. Maintain between 100% and the allowed overshoot of the stated amount (MW) of CONTINGENCY RESERVE – SPINNING for at least 15 minutes subsequent to (T_{DCS} – X).

9.3. Return to the non-contingency scheduled output (or consumption) +/– 10% of the requested amount of CONTINGENCY RESERVE, within ten minutes of instructions from the BALANCING AUTHORITY to do so. Alternatives to the +/- 10% bandwidth and the ten minute period may be established by the BALANCING AUTHORITY through an open process defined in Requirement 2 - Section 3.1 – OPERATING AUTHORITY Requirements.

10. **Maintaining Reserve Capacity.** An IOS SUPPLIER shall maintain the capacity committed to provide CONTINGENCY RESERVE throughout the commitment period.

11. **Metering and Communication.** An IOS SUPPLIER offering to provide CONTINGENCY RESERVE shall meet the following minimum metering and communication requirements:

11.1. The IOS SUPPLIER shall provide to the BALANCING AUTHORITY real-time telemetry of the real power output of each IOS RESOURCE providing CONTINGENCY RESERVE.

11.2. The IOS RESOURCE shall have a BALANCING AUTHORITY approved data communication service between the IOS RESOURCE control interface and the BALANCING AREA.

11.3. The IOS RESOURCE shall have a BALANCING AUTHORITY approved voice communication service to provide both primary and alternate voice communication between the BALANCING AUTHORITY and the operator controlling the IOS RESOURCE.

3.4 Sample REACTIVE POWER SUPPLY FROM GENERATION SOURCES Requirements

Sample Requirements – OPERATING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Voltage Schedule Coordination.** The OPERATING AUTHORITY shall establish, and update as necessary, voltage schedules at points of integration of REACTIVE POWER SUPPLY FROM GENERATION SOURCES, to maintain system voltages within established limits and to avoid burdening neighboring systems. The OPERATING AUTHORITY shall communicate to the IOS SUPPLIER the desired voltage at the point of integration.

IOS RESOURCE here refers only to those resources providing REACTIVE POWER SUPPLY FROM GENERATION SOURCES.

2. **Reactive Reserves.** The OPERATING AUTHORITY shall acquire, deploy, and continuously maintain reactive reserves from IOS RESOURCES, both leading and lagging, adequate to meet contingencies.

3. **Telemetry.** The OPERATING AUTHORITY shall monitor by telemetry the following data:

3.1. Transmission voltages.

3.2. Unit or IOS RESOURCE reactive power output.

3.3. Unit or IOS RESOURCE Automatic Voltage Regulator (AVR) status for units greater than 100 MW (and smaller units where an identified need exists).

4. **NERC Planning Standards.** The OPERATING AUTHORITY shall comply with NERC Planning Standards applicable to reactive power capability. These standards require that generation owners and OPERATING AUTHORITIES plan and test reactive power capability.

Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

5. **Automatic Voltage Regulator.** An IOS RESOURCE shall operate with the unit's AVR in use during the schedule period in which REACTIVE POWER SUPPLY FROM GENERATION SOURCES is provided, unless specifically directed to operate in manual mode by the OPERATING AUTHORITY, or a need to operate in manual mode is identified for emergency reasons by the IOS SUPPLIER. When the IOS SUPPLIER changes the mode, the IOS SUPPLIER shall promptly inform the OPERATING AUTHORITY.

6. **Response to Voltage or Reactive Power Schedule Changes.** IOS RESOURCES shall meet, within established tolerances, and respond to changes in the voltage or reactive power schedule established by the OPERATING AUTHORITY, subject to the stated IOS RESOURCE reactive and real power operating characteristic limits and voltage limits.

7. **Reactive Capacity.** IOS RESOURCES shall maintain stated reactive capacity, both leading and lagging. An IOS RESOURCE's stated lagging reactive capacity shall be supplied without interruption or degradation when subject to sudden and large voltage drops.

8. **Telemetry.** IOS RESOURCES shall provide electronic transfer of real-time information to the OPERATING AUTHORITY:

   8.1. Voltages at the IOS RESOURCE point of delivery to the OPERATING AUTHORITY.

   8.2. IOS RESOURCE reactive power output, and

   8.3. IOS RESOURCE AVR status for units of greater than 100 MW of nameplate capacity (and smaller units where an identified need exists).

3.5 Sample FREQUENCY RESPONSE Requirements

Sample Requirements – BALANCING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Written Requirements.** The BALANCING AUTHORITY shall determine the IOS requirements for FREQUENCY RESPONSE in accordance with Requirement 2 of Section 3.1 – Operating Authority Sample Requirements. These requirements may include the amount, location, and response characteristics.

2. **Provision.** The BALANCING AUTHORITY shall assure sufficient capabilities for FREQUENCY RESPONSE are arranged, provided, and deployed to meet NERC, applicable Regional Reliability Council, and local operating requirements.

3. **Verification of Performance.** The BALANCING AUTHORITY shall verify that all IOS RESOURCES contracted to provide FREQUENCY RESPONSE do so according to established performance criteria, including reaching the requested amount of real power output within and for the specified time limits.

Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

4. **Declaration of FREQUENCY RESPONSE Capability.** Prior to providing FREQUENCY RESPONSE, the IOS SUPPLIER shall declare the FREQUENCY RESPONSE capabilities of the IOS RESOURCES.

5. **Governor.** An IOS RESOURCE providing FREQUENCY RESPONSE capability shall maintain an operable governor system and shall be responsive to system frequency deviations.

6. **Maintaining FREQUENCY RESPONSE Capacity.** An IOS SUPPLIER shall maintain the governor response capability to provide FREQUENCY RESPONSE throughout the commitment period.

7. **Metering and Communication.** An IOS SUPPLIER offering to provide FREQUENCY RESPONSE shall have frequency metering and generation output metering sufficient to determine on an after the fact basis that the generator delivered the response required.

3.6 SYSTEM BLACK START CAPABILITY

Sample Requirements – OPERATING AUTHORITY

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

1. **Restoration Plans.** The OPERATING AUTHORITY shall verify that restoration plans meet NERC, applicable Regional Reliability Council, and local requirements, and provide for adequate SYSTEM BLACK START CAPABILITY.

2. **System Black Start Requirements.** The OPERATING AUTHORITY shall determine the overall required amount and locations of SYSTEM BLACK START CAPABILITY in a system restoration plan for the coordinated re-energization of the transmission network following a total or partial system blackout.

3. **Training and Drills.** The OPERATING AUTHORITY shall include IOS RESOURCES providing SYSTEM BLACK START CAPABILITY in the conduct of system-wide training, and drills, as necessary to prepare a coordinated response to a partial or total system blackout condition.

4. **Provision of SYSTEM BLACK START CAPABILITY.** The OPERATING AUTHORITY shall ensure IOS RESOURCES for SYSTEM BLACK START CAPABILITY are arranged, provided, and deployed as necessary to reenergize the transmission network following a total or partial system blackout.

5. **Testing and Verification**. The OPERATING AUTHORITY shall schedule random testing or simulation, or both, to verify SYSTEM BLACK START CAPABILITY is operable according to the restoration plan. Testing and verification will be in accordance with established certification criteria. These tests and/or simulations shall ensure that the SYSTEM BLACK START CAPABILITY resources and the transmission system are configured such that the SYSTEM BLACK START CAPABILITY resources are able to energize the appropriate portions of the transmission system, and supply restoration power to the generator(s) or load(s), as required by the restoration plan.

The SYSTEM BLACK START CAPABILITY resources must provide frequency and voltage within prescribed limits during line energization and remote load pickup.

6. **Performance Verification.** The OPERATING AUTHORITY shall verify the actual performance of SYSTEM BLACK START CAPABILITY resources in the event actual system blackout conditions occur.

Sample Requirements – IOS SUPPLIER

The statements below are provided for information only and do not infer mandatory requirements or a description of industry practices.

7. **IOS RESOURCE Capabilities.** An IOS SUPPLIER of SYSTEM BLACK START CAPABILITY shall provide the following:

   7.1. Capability to start a self-starting unit within a time specified, from an initial dead station and auxiliary bus condition. Alternately, a SYSTEM BLACK START CAPABILITY resource may be a generating unit that is able to a) safely withstand the sudden and unplanned loss of synchronization with the BULK ELECTRIC SYSTEM and b) maintain generating capacity for a specified period of time.

   7.2. Capability of re-energizing, within a time specified, the plant auxiliaries necessary to start one or more additional units, if the SYSTEM BLACK START CAPABILITY unit is planned as a cranking source for one or more of these additional units.

   7.3. Capability of picking up external load within a specified time.

   7.4. Stated MW capacity of the SYSTEM BLACK START CAPABILITY unit or units.

   7.5. Capability of running the SYSTEM BLACK START CAPABILITY unit at stated MW capacity for a specified time from when the unit is started.

   7.6. Frequency measurement at the SYSTEM BLACK START CAPABILITY unit to support the system restoration plan.

   7.7. Frequency responsive capability to sustain scheduled frequency and remain stable during load pickup coordinated by the OPERATING AUTHORITY in accordance with the restoration plan.

   7.8. Reactive supply and voltage control capability to maintain system voltage within emergency voltage limits over a range from no external load to full external load.

   7.9. Participation in training and restoration drills coordinated by the OPERATING AUTHORITY.

   7.10. Provision of voice and data communications with the OPERATING AUTHORITY, capable of operating without an external AC power supply for a specified time.

Section 4. Methods for IOS Performance Measurement and Certification

4.1 Introduction

This Section offers metrics for measuring the performance of IOS RESOURCES and certifying IOS-related capabilities. The metrics focus on the key parameters needed for reliability and test or measure these characteristics as precisely and efficiently as possible. The metrics described are examples of measures. Other measures may be valid and appropriate to achieve the same reliability objectives.

Performance measures assess the real-time delivery of a service by an IOS SUPPLIER. By design, the extent of the certification tests is inversely related to the ease of measuring real-time performance. For example, the certification test for the REGULATION is quite simple because REGULATION is delivered on a continuous basis. On the other hand, the certification test for the SYSTEM BLACK START CAPABILITY is more extensive because this service is rarely delivered, and, therefore, cannot routinely be measured. IOS that are deployed only occasionally (e.g., CONTINGENCY RESERVE) have a certification test that is more extensive than REGULATION but simpler than that for SYSTEM BLACK START CAPABILITY.

Performance measures can be monitored at the IOS SUPPLIER (i.e., aggregated) level. This allows the IOS SUPPLIER to meet performance requirements in a flexible manner while holding the IOS SUPPLIER accountable for the aggregate performance of its individual IOS RESOURCES. Certification requirements also potentially allow for a group or portfolio of physical assets to be certified in aggregate. However, if the IOS RESOURCES that comprise the portfolio are modified to the extent that the certified capabilities are affected, then re-certification should be necessary.

The performance metrics presented in this IOS Reference Document were developed to meet three criteria:

- Support reliability objectives of the OPERATING AUTHORITY (e.g., meet Policy 1 requirements for CPS and DCS);
- Be technically justified; and
- Operate well in a variety of regulatory frameworks and market structures and conditions.

Each performance metric includes three components. The *measure* (e.g., area control error) identifies the characteristic to be measured (analogous to miles per hour for a highway speed limit). The *criteria* bound the measure (e.g., CPS1 and 2 for area control error or 65 miles per hour for a speed limit). Finally, the metric may include *conditions* under which the measurements apply (e.g., the Policy 1 DCS measure applies only after a major contingency occurs or speed limits differ between rural freeways and urban roads). The criteria numbers are proposed as a starting point, and will likely need to be changed with experience.

4.2 Performance Measurement Methods

REGULATION and LOAD FOLLOWING Sample Performance Measures

IOS RESOURCES providing REGULATION and LOAD FOLLOWING service deliver capacity, MANEUVERABILITY, and energy to the BALANCING AUTHORITY. The measurement methods described below are intended to determine if sufficient capacity, maneuverability, and energy have been delivered

to maintain reliability.

The deviation between the output instructed by the BALANCING AUTHORITY, subject to the declared capabilities of the IOS RESOURCE, and the actual output of the IOS RESOURCE is defined as the SUPPLIER CONTROL ERROR (SCE). Each IOS SCE must be bounded within the SCPS1 and SCPS2 criteria as defined below.

Figure 5 below demonstrates the concept of Supplier Control Error as the deviation between instructed output, subject to declared capabilities, and actual output.

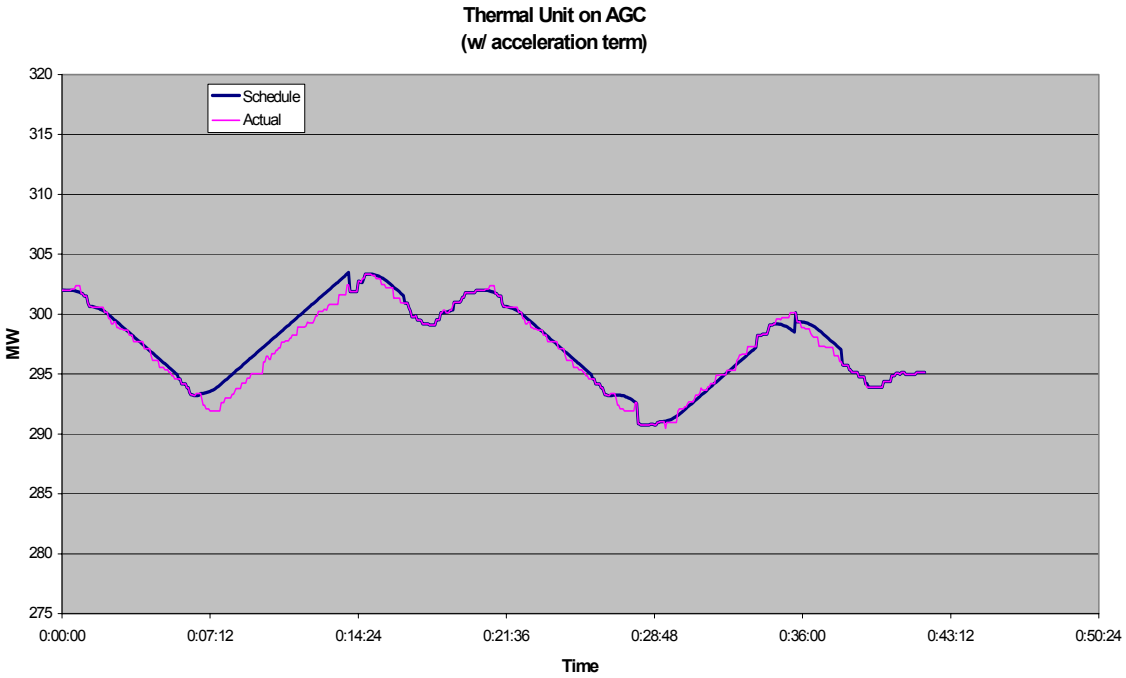

Figure 5 – Supplier Control Error: Deviation between Schedule and Actual Output

Figure 6 demonstrates one method for the determination of the scheduled output of a resource.

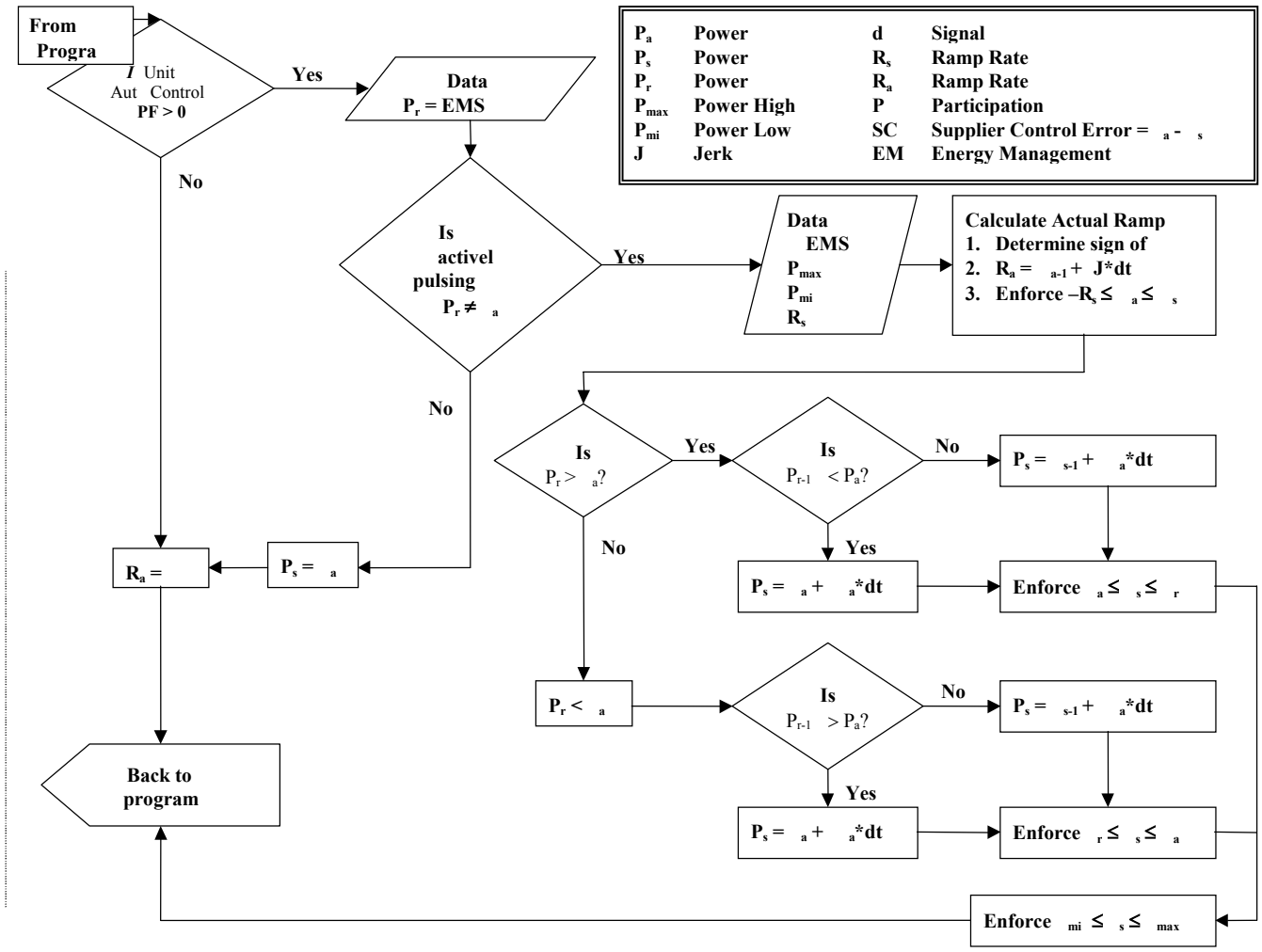

Figure 6 – Determination of IOS RESOURCE Schedule

Figure 7 provides one method for the calculation of SUPPLIER CONTROL ERROR (SCE).

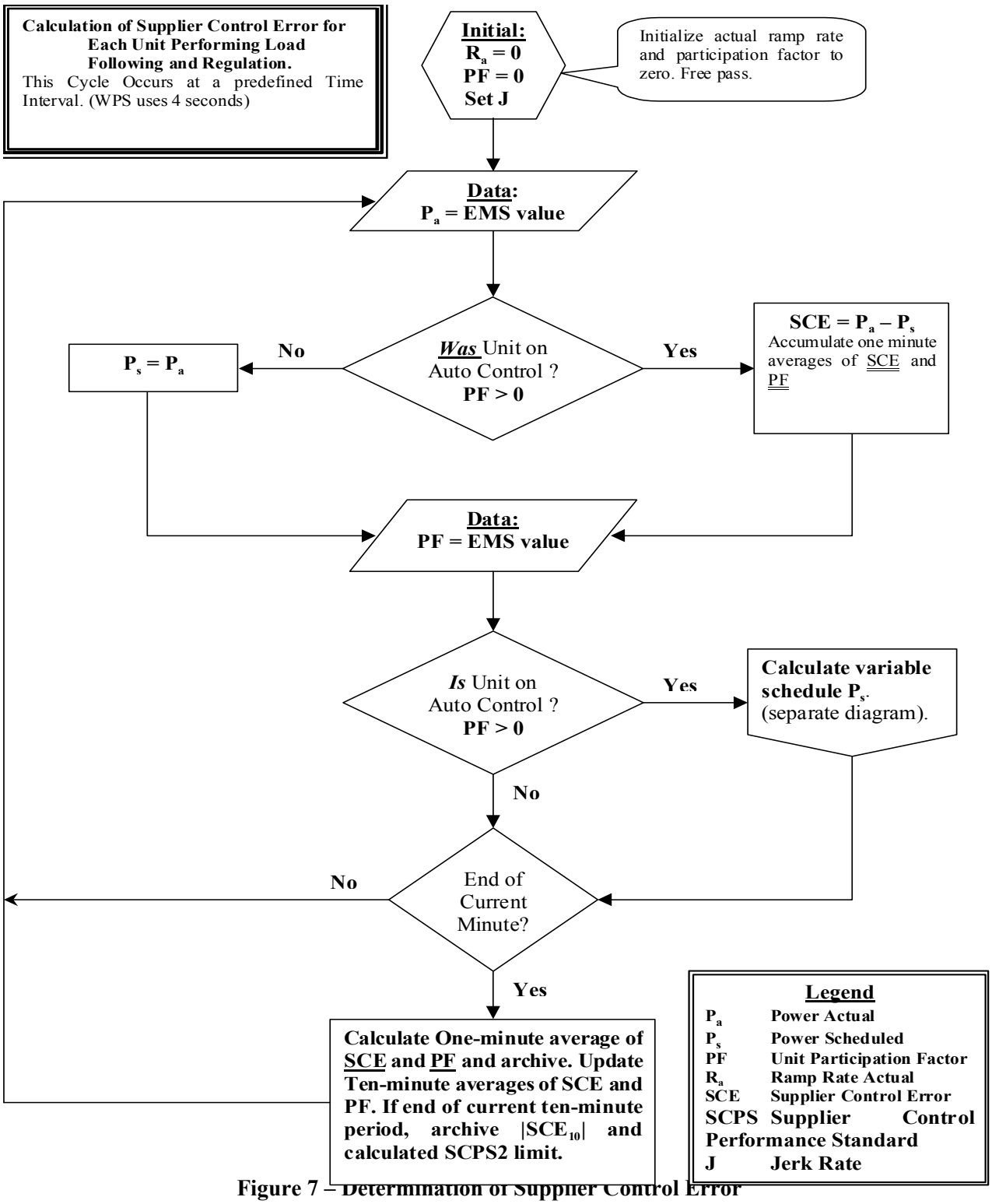

Figure 7 – Determination of Supplier Control Error

Consider that the control signal given to the IOS RESOURCE, subject to the stated capabilities of the IOS RESOURCE, constitute an agreed upon variable schedule. Deviation of actual output from this schedule is the measure of performance (the Supplier Control Error SCE). Compliance is measured with three criteria:

- SCPS1 (an analogy to Policy 1 CPS1)
- Covariance (SCE/pf,ACE)≤ Limit
- Average (SCE) = 0
- SCPS2 (an analogy to Policy 1 CPS2)

Let us consider, in general terms, the SCPS2 criterion. This criterion requires that the IOS RESOURCE match its actual output to its schedule within a predefined bandwidth for 90% of all measurement periods (10-minute average). In equation form this criterion is described as follows:

$$SCPS2 = \left(\frac{NumberofCompliantPeriods}{TotalNumberofPeriods} \right) \geq 0.90$$

$$CompliantPeriod_when_|SCE_{10}| \leq L_{10} * \frac{\sqrt{ParticipationFactor}}{\sum_i \sqrt{ParticipationFactor_i}}$$

where: $|SCE_{10}|$ is the 10-minute average of SCE
Participation Factor = Response Rate/(Sum of all Response Rates)
L_{10} is the control area's CPS2 bound

By requiring the IOS RESOURCE to produce output within a bandwidth around the variable schedule, the SCPS2 criterion measures capacity and maneuverability. Unfortunately, the SCPS2 criterion alone is insufficient. An IOS RESOURCE could consistently produce at the bottom of the bandwidth. This would violate the "energy" attribute of the service. In addition, the IOS RESOURCE could systematically time its errors within the bandwidth to the detriment of reliability: overproducing during times of plenty and under producing during times of shortage. To address these two shortcomings of SCPS2, another criterion is required.

Let us consider, in general terms, the SCPS1 criterion. This criterion requires that the IOS RESOURCE match its actual output to its schedule such that (1) in the long run the scheduled energy equals the actual energy and (2) the timing of the error with respect the control area ACE or the Frequency Error is sufficiently favorable to maintain reliability. In equation form the criteria are described as follows:

$$Avg_{month}(SCE_1) \approx 0$$

And:

$$SCF = AVG(month)\left[\left(\frac{SCE_1}{ParticipationFactor} \right) * \left(\frac{\Delta F_1}{(-10 * Bias) * \varepsilon^2{}_1} \right) \right]$$

or:

$$SCF = AVG(month)\left[\left(\frac{SCE_1}{ParticipationFactor}\right)*\left(\frac{ACE_1}{\gamma_1^2}\right)\right]$$

With:

$$SCPS1 = (2 - SCF)$$

where: SCE_1 is the one minute average Supplier Control Error
Participation Factor = Response Rate/(Sum of all Response Rates)
ΔF_1 is the one-minute average frequency error
Bias is the control area bias
ε_1 is NERC Policy 1 CPS1 limit
ACE_1 is the control area's one-minute average area control error
γ_1 is the IOS SUPPLIER limit determined by NERC. This value uniquely modifies ε_1 for each control area depending on its correlation between ACE and ΔF.
(Note: the specific limit for SCPS1 score is not set forth in this document. Limits between 180% and 200% have been proposed.)

The IOS RESOURCE that is compliant with SCPS1 and SCPS2 operates within a bandwidth, delivers the correct amount of energy, and does not time its errors in a manner detrimental to reliability. This assures that the service attributes of capacity, maneuverability, and energy have been adequately delivered.

Figures 8 and 9 demonstrate the SCPS1 and SCPS2 performance evaluation of 15 units on a sample system.

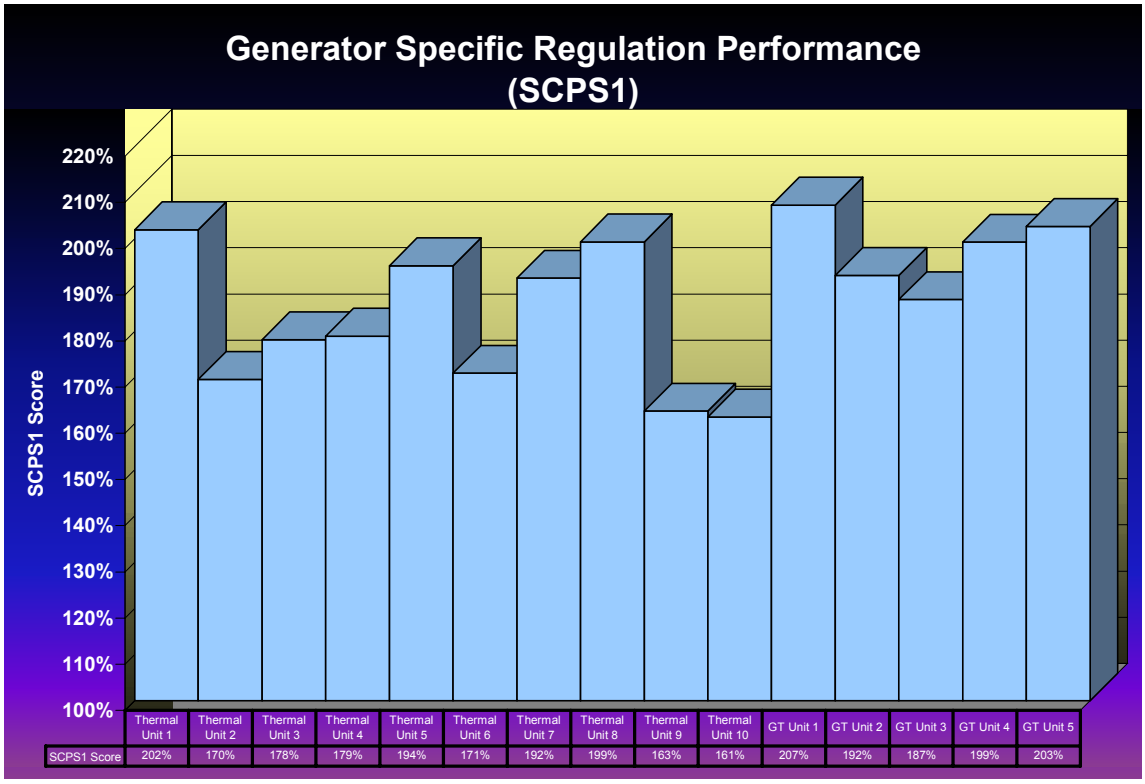

Figure 8 – Sample Regulation SCPS1 Performance Measures for IOS Resources

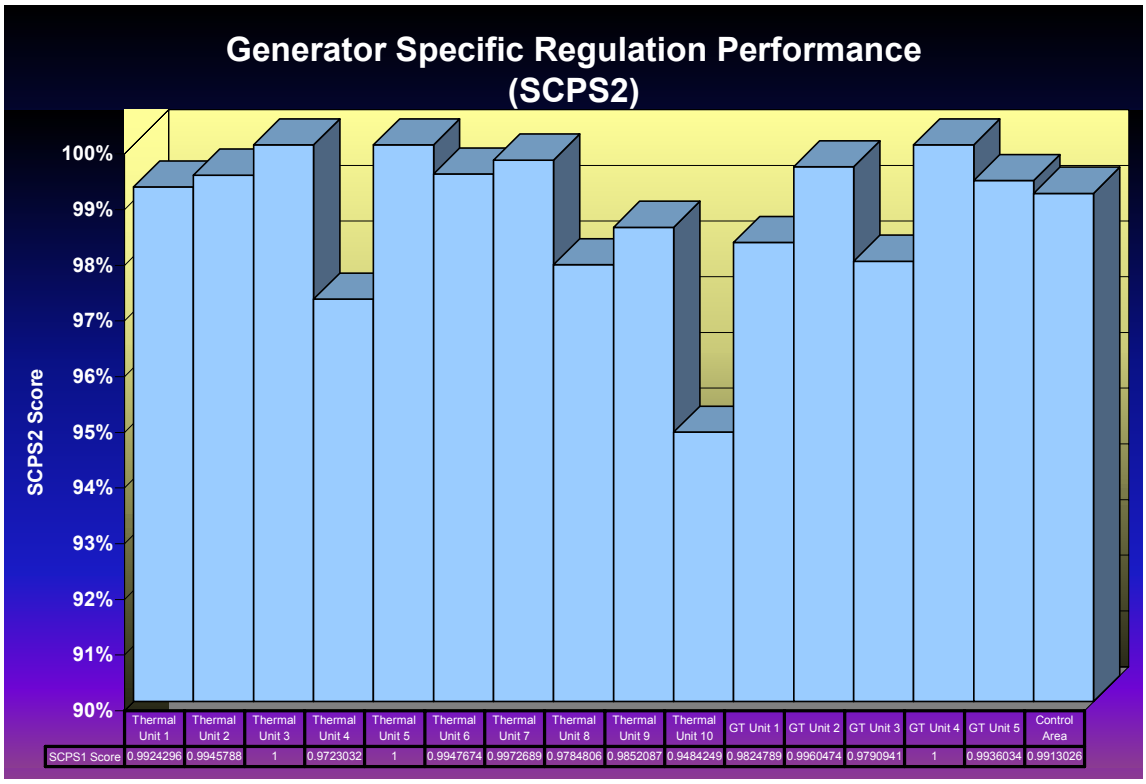

Figure 9 - Sample Regulation SCPS2 Performance Measures for IOS Resources

From this information, one may also determine the Regulation participation of individual IOS Resources, as shown in Figure 10.

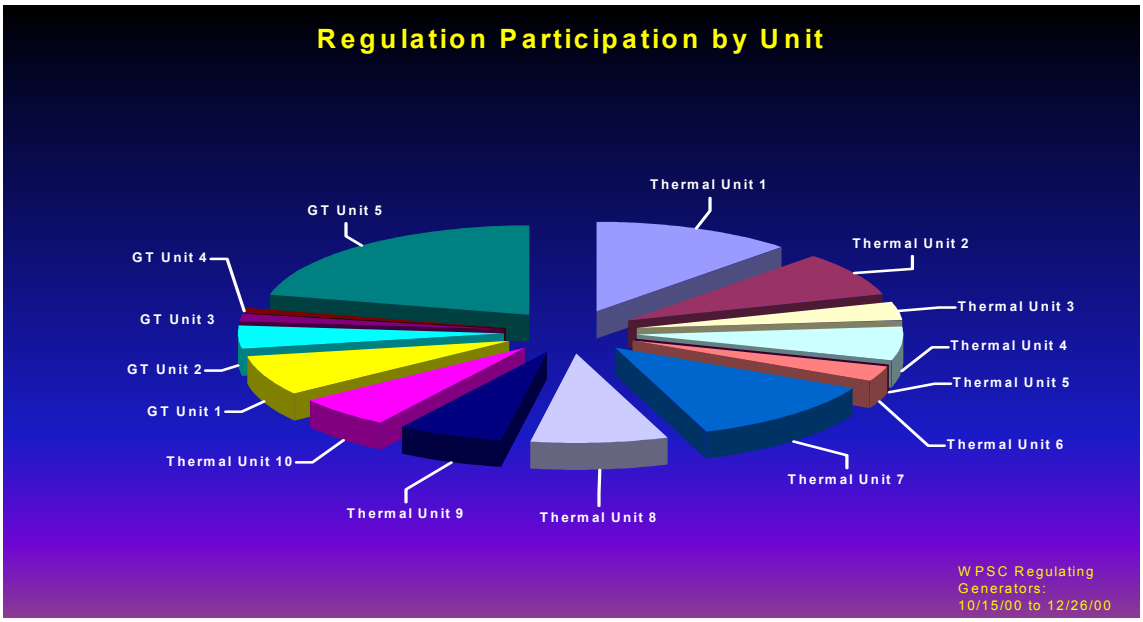

Figure 10 – Sample Determination of Regulation Participation

Additionally, this information allows one to determine the contribution of Supplier performance to the Control Area's CPS1 score, shown in Figure 11.

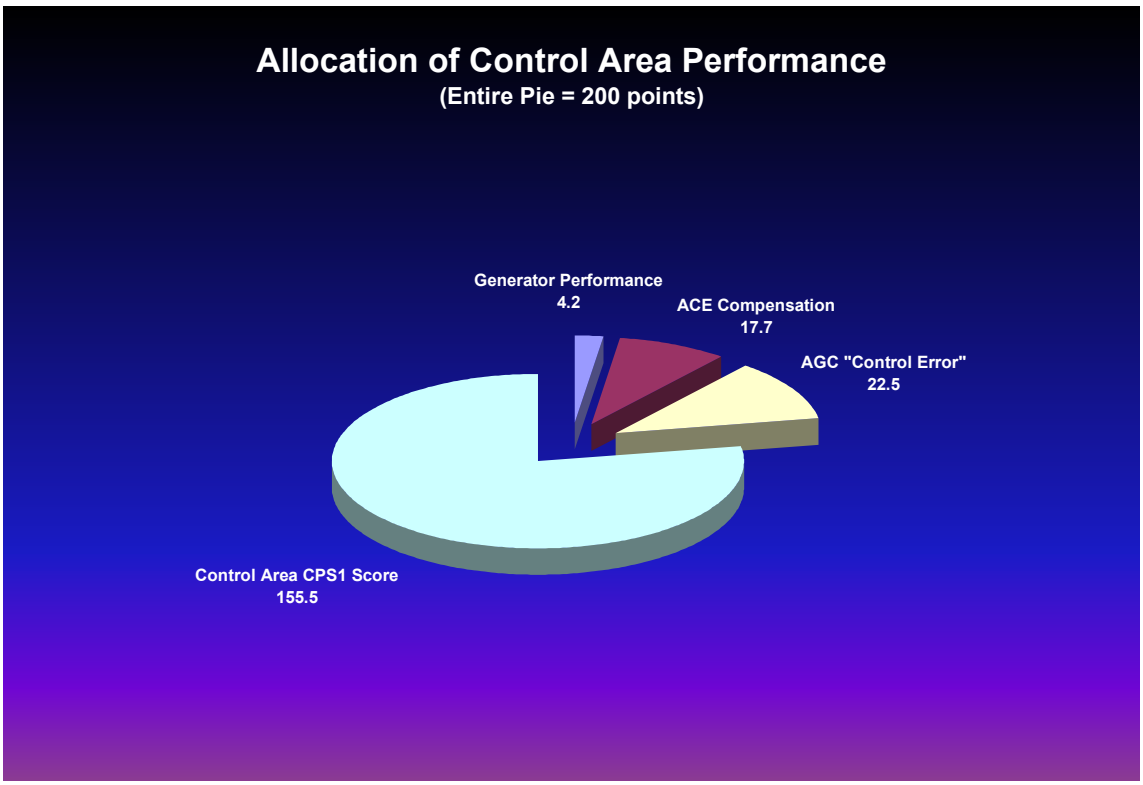

Figure 11 – Sample Determination of Regulation Participation

CONTINGENCY RESERVE Sample Performance Measures

In response to the instructions of the BALANCING AUTHORITY, and subject to the declared capabilities of the IOS RESOURCE, the IOS RESOURCE shall provide at least 100%, and not greater than 120%, of the stated real power (MW) amount within ($T_{DCS} - X$) minutes of the receipt of the instructions. The variable "X" is the OPERATING AUTHORITY notification delay. Furthermore, the IOS RESOURCE shall maintain between 100% and 120% of the stated real power (MW) amount for the 20 minutes (or for the CONTINGENCY RESERVE deployment period) following T_{DCS}. Finally, the IOS RESOURCE shall go to within 90% to 110% of its post-contingency scheduled output, subject to the declared capabilities of the IOS RESOURCE, within 10 minutes following instructions from the OPERATING AUTHORITY.

For each IOS RESOURCE providing CONTINGENCY RESERVES, the BALANCING AUTHORITY shall measure and record for the entire duration of the CONTINGENCY RESERVE deployment the one-minute averages of real power output and the instructed output, subject to the declared capabilities of the IOS RESOURCE.

The expected performance criteria are that the IOS RESOURCE loads, sustains, and unloads the stated CONTINGENCY RESERVE amount in MW, within the allowed band-width of 100% to 120%, in the time periods stated in the standard:

- Loads instructed CONTINGENCY RESERVES within ($T_{DCS} - X$) minutes,
- Sustains instructed CONTINGENCY RESERVES for the 20 minutes following ($T_{DCS} - X$) minute loading window, and
- Unloads instructed CONTINGENCY RESERVES within 10 minutes of instruction to unload and goes to within 90% to 110% of post-contingency scheduled output, subject to stated capabilities of the IOS RESOURCE.

REACTIVE POWER SUPPLY FROM GENERATION SOURCES Sample Performance Measures

IOS RESOURCES shall meet, within established tolerances, and respond to changes in the voltage or reactive power schedule established by the OPERATING AUTHORITY, subject to the stated IOS RESOURCE reactive and real power operating characteristic limits and voltage limits.

An IOS RESOURCE shall operate with the unit's AVR in use during the schedule period in which REACTIVE POWER SUPPLY FROM GENERATION SOURCES is provided, unless specifically directed to operate in manual mode by the OPERATING AUTHORITY, or a need to operate in manual mode is identified for emergency reasons by the IOS SUPPLIER.

IOS RESOURCES shall maintain stated reactive capacity, both leading and lagging. An IOS RESOURCE's stated lagging reactive capacity shall be supplied without interruption or degradation when subject to sudden and large voltage drops.

When an IOS RESOURCE is controlling to a voltage set point under steady state conditions, the IOS RESOURCE Voltage Schedule Error ($V_{ACTUAL} - V_{SCHEDULE}$) shall be measured and reported quarterly by the OPERATING AUTHORITY once per each 10-minute period during all scheduling periods in which the IOS RESOURCE is providing the service. 98% of Voltage Schedule Errors Reported in a quarter are within the Voltage Tolerance ($\pm$ 2% of Scheduled), subject to the stated capabilities of IOS RESOURCE.

When an IOS RESOURCE is controlling to reactive power output under steady state conditions, the IOS RESOURCE Reactive Power Output Error ($VAR_{ACTUAL} - VAR_{SCHEDULE}$) shall be measured and reported quarterly by the OPERATING AUTHORITY once per each 10-minute period during all scheduling periods in

which the IOS RESOURCE is providing the service. 95% of Reactive Power Output Errors Reported in a quarter are within the Reactive Tolerance (± 10% of Scheduled), subject to the stated capabilities of IOS RESOURCE.

The status of the AVR shall be reported quarterly by the IOS SUPPLIER to the OPERATING AUTHORITY for the entirety of all scheduling periods in which the IOS RESOURCE is providing the service. AVR is on and operating automatically at least 98% of the time in which the IOS RESOURCE is providing the service. Percentage is calculated as: (Time AVR is on While Providing IOS) / (Total Time Providing IOS) X 100%.

FREQUENCY RESPONSE Sample Performance Measures

In response to the deviations in system frequency, and subject to the declared capabilities of the IOS RESOURCE such as dead-band and droop, the IOS RESOURCE shall increase or decrease its output according to its stated response characteristic.

For all frequency deviations exceeding the NERC frequency excursion values (Policy 1 epsilon values times an Interconnection-specific factor), the OPERATING AUTHORITY shall measure and record scan rate (e.g. AGC scan rate) values of real power output for the IOS RESOURCE providing FREQUENCY RESPONSE. The OPERATING AUTHORITY shall measure and record the MW data beginning one minute prior to the start of the frequency excursion event until one minute after the start of the frequency excursion event. Compliance is measured by comparing the actual response to the declared frequency response capability.

SYSTEM BLACK START CAPABILITY Sample Performance Measures

The IOS SUPPLIER shall maintain certified SYSTEM BLACK START CAPABILITY IOS RESOURCES, with the declared capacity and capabilities of the IOS RESOURCES, continuously during all periods in which SYSTEM BLACK START CAPABILITY is provided. During a system restoration emergency, the IOS SUPPLIER shall respond to the instructions of the OPERATING AUTHORITY, subject to the declared capacity and capabilities of the SYSTEM BLACK START CAPABILITY IOS RESOURCES.

The following performance measures may be monitored during an emergency: During emergency activation and in response to instructions of the OPERATING AUTHORITY, the IOS RESOURCE:

- Is able to start and synchronize to the power system within the agreed upon time; and
- Is able to provide full declared real and reactive power capabilities.

4.3 Certification Methods

Introduction to Certification Methods

Certification is a means to demonstrate the capability of an IOS Resource to deliver an IOS. Certification increases reliability since it offers assurances to all industry participants that promised capabilities can be deployed and utilized when needed for reliability reasons. In practice, the cost and effort of a certification program needs to be balanced against the reliability impact should the promised capabilities not be delivered when requested, and the probability of delivery shortfalls.

REGULATION and LOAD FOLLOWING may be continuously measured. Therefore no certification requirements are suggested beyond the general certification requirements for all IOS.

This section contains sample certification methods for CONTINGENCY RESERVE, REACTIVE POWER SUPPLY FROM GENERATION SOURCES, FREQUENCY RESPONSE, and SYSTEM BLACK START CAPABILITIES.

OPERATING AUTHORITY Sample IOS Program Certification

The following certification requirements of the OPERATING AUTHORITY should be verified annually through self-assessment and every three years by an entity external to the OPERATING AUTHORITY.

Documentation should be verified to show that the OPERATING AUTHORITY has developed and is maintaining and executing a program to specify and provide IOS in accordance with each OPERATING AUTHORITY requirement in Section 3 of the IOS Reference Document. The following minimum elements should be considered in the review of documentation of the OPERATING AUTHORITY's IOS program:

1. A detailed plan and procedures to assure sufficient IOS are arranged, provided, and deployed to meet NERC, Regional Reliability Council, and local planning and operating standards.

2. Detailed specifications of the OPERATING AUTHORITY's requirements for IOS, which have been determined through an open and inclusive process that is consistent with regulatory requirements, is coordinated at a regional level, includes market stakeholders, and allows for dispute resolution. The specifications shall include, but are not limited to:

    2.1. The quantity, response time, duration, location and other criteria for each IOS.
    2.2. Written procedures for the arrangement, provision, and deployment of IOS.
    2.3. Metering requirements.
    2.4. Voice and data communication requirements associated with provision and deployment of IOS.
    2.5. Specification of the transmission service requirements for delivery of each IOS.

3. Procedures for adapting the IOS requirements to maintain system reliability in response to current or expected system conditions.

4. Publication of IOS requirements in publicly available documents that specify the OPERATING AUTHORITY's IOS requirements and procedures.

5. Procedures for monitoring the actual performance of IOS RESOURCES under normal and/or disturbance conditions to verify the IOS RESOURCE meets published performance criteria.

General Certification – Sample Criteria

The following are sample certification requirements that could apply to all IOS. These requirements would be evaluated by audit or other means of verification.

1. **Metering** – An IOS SUPPLIER shall provide and maintain metering to measure IOS capabilities and performance, as specified by published IOS requirements.

2. **Voice and Data Communications** – An IOS SUPPLIER shall provide and maintain voice and data communications, as specified by published IOS requirements, to enable:

2.1. IOS RESOURCES to respond to the instructions or controls of the OPERATING AUTHORITY.

2.2. OPERATING AUTHORITIES to monitor the capabilities and verify the performance of IOS RESOURCES.

CONTINGENCY RESERVE Certification Method

The following is a sample certification test for CONTINGENCY RESERVE – SPINNING and SUPPLEMENTAL:

1. A test for CONTINGENCY RESERVE – SPINNING or SUPPLEMENTAL shall be performed during a continuous 8-hour window agreed upon by the IOS SUPPLIER and the BALANCING AUTHORITY.

2. The BALANCING AUTHORITY shall confirm the date and time of the test with the IOS RESOURCE using both the primary and alternate voice circuits to validate the voice circuits.

3. At any time during the eight-hour window, selected by the BALANCING AUTHORITY, and not previously disclosed to the IOS SUPPLIER, the BALANCING AUTHORITY shall send a signal to the IOS RESOURCE requesting it to provide its declared amount of CONTINGENCY RESERVE – SPINNING OR SUPPLEMENTAL.

4. The IOS RESOURCE output shall be measured as clock-minute average outputs for a) the clock-minute prior to the instructions being received from the BALANCING AUTHORITY; b) the clock-minute following receipt of instructions from the BALANCING AUTHORITY and continuing for T_{DCS} - X minutes (where T_{DCS} is the number of minutes allowed by the Policy 1 Disturbance Control Standard for recovery from a major outage and X is the previously agreed upon time that the BALANCING AUTHORITY requires to identify the need to deploy the reserves and to notify the IOS RESOURCE); c) and for each of the subsequent 19 clock-minutes. All measurements shall be between 100% to Y% of the declared amount of CONTINGENCY RESERVE, where Y is an INTERCONNECTION-specific factor.

REACTIVE POWER SUPPLY FROM GENERATION SOURCES Certification

The following is a sample certification test for REACTIVE POWER SUPPLY FROM GENERATION SOURCES:

1. The IOS RESOURCE shall perform the unit automatic voltage regulator (AVR) tests, and supply IOS RESOURCE AVR data as required by the NERC Planning Standards "System Modeling Data Requirements, Generation Equipment." Sections 2B, Measurement 4, and 2B, Measurement 6. The AVR tests will be performed upon initial certification, and periodically at an OPERATING AUTHORITY set time interval no more often than once every five years. The AVR tests are run at a time mutually agreed upon in advance by the IOS SUPPLIER and the OPERATING AUTHORITY.

2. The IOS RESOURCE must verify and maintain its stated reactive capacity, as required by the NERC Planning Standards "System Modeling Data Requirements, Generation Equipment." Sections 2.B, Measurement 3. This reactive capacity certification test will verify the IOS RESOURCE reactive capacity. The reactive capacity test will be performed upon initial certification, and periodically at an OPERATING AUTHORITY set time interval no more often than once every five years. The reactive capacity test is run at a time mutually agreed upon in advance by the IOS SUPPLIER and the OPERATING AUTHORITY. The test results, as described in 2.B, Measurement 3, shall be communicated to the OPERATING AUTHORITY.

FREQUENCY RESPONSE Certification

The following is a sample certification test for FREQUENCY RESPONSE:

1. The BALANCING AUTHORITY shall confirm the date and time of the test with the IOS RESOURCE. The FREQUENCY RESPONSE test should be performed at a time that is mutually agreed upon by the IOS SUPPLIER and BALANCING AUTHORITY.

2. Because it is impractical to move INTERCONNECTION frequency for test purposes, it is necessary to use simulated frequency excursions outside the allowed deadband to perform a certification test of the IOS RESOURCE. A test frequency signal will be provided to the IOS RESOURCE and the IOS RESOURCE'S response will be measured. The frequency value of the test signal will be calculated to require the full response amount (MW) being certified, based on the IOS RESOURCE'S deadband and droop characteristic. The pre-contingency output (or consumption) of the IOS RESOURCE shall be calculated as the average power recorded for the clock minute prior to the injection of the test frequency signal. After each frequency test signal is injected, the test measurements shall include the MW output (or consumption) ten seconds after the frequency change and the average for each clock-minute from ten seconds through ten minutes following each frequency change. To pass the test, the measured values must differ from the pre-contingency output (or consumption) within the bounds listed in the FREQUENCY RESPONSE criteria.

3. It may be necessary to construct alternative tests for IOS RESOURCES that cannot produce (or consume) real power while connected to a test frequency source. In this case, output (or consumption) may be calculated based upon measured performance of that portion of the system that can be tested (throttle valve position, for example). Testing requirements should be negotiated between the IOS SUPPLIER and the BALANCING AUTHORITY.

SYSTEM BLACK START CAPABILITY Certification

The following sample SYSTEM BLACK START CAPABILITY certification tests are divided into three parts, depending on the frequency of testing required.

Basic Starting Test – The basic ability of the IOS RESOURCE to start itself, without support from the grid, should be tested at least once every three years. The test is run during a one-week period mutually agreed upon in advance by the IOS SUPPLIER and OPERATING AUTHORITY. The test itself does not require one week, but may be called by the OPERATING AUTHORITY any time during the week.

1. The OPERATING AUTHORITY shall confirm the dates of the test with the IOS SUPPLIER.

2. At a time during the one-week test window, selected by the OPERATING AUTHORITY, and not previously disclosed to the IOS RESOURCE:

    2.1. The IOS RESOURCE, including all auxiliary loads, will be isolated from the power system;

    2.2. Within the agreed upon time of being directed to do so by the OPERATING AUTHORITY, the IOS RESOURCE will start without assistance from the system; and

    2.3. The IOS RESOURCE must remain stable (both frequency and voltage) while supplying only its own auxiliary loads or loads in the immediate area for at least 30 minutes.

Line Energizing Test – The ability of the IOS RESOURCE to energize transmission will be tested when conditions permit (during transmission maintenance, for example) but at least once every three years. Tests will be conducted at a time mutually agreed upon by the IOS SUPPLIER and the OPERATING AUTHORITY. If an actual Line Energizing Test is impractical or presents a condition that may pose an undesired risk of load service interruption, these tests may be conducted by steady state and dynamic computer simulation. It should be noted, however, that impediments to system restoration may occur that are not fully modeled in simulations.

1. Sufficient transmission will be de-energized such that when it is picked up by the IOS RESOURCE it demonstrates the IOS RESOURCE'S ability to energize enough transmission to deliver required output to the generator or load that the restoration plan calls for this IOS RESOURCE to supply. The OPERATING AUTHORITY shall be responsible for transmission connections and operations that are compatible with the capabilities of the IOS RESOURCE.

2. Conduct a **Basic Starting Test**.

3. The CONTROL AREA will direct the IOS RESOURCE to energize the previously de-energized transmission, while monitoring frequency and voltages at both ends of the line. Alternatively, if the OPERATING AUTHORITY agrees, the transmission line can be connected to the IOS RESOURCE before starting, allowing the resource to energize the line as it comes up to speed. This avoids the energizing surge.

4. The IOS RESOURCE must remain stable (both frequency and voltage) while supplying only its own auxiliary loads or external loads and controlling voltage at the remote end of the transmission line for at least 30 minutes.

Load Carrying Test – The ability of the IOS RESOURCE to remain stable and to control voltage and frequency while supplying restoration power to the generator or load that the restoration plan calls for this IOS RESOURCE to supply shall be tested as conditions permit, but at least once every six years. If an actual Load Carrying Test is impractical or presents a condition that may pose an undesired risk of load service interruption, these tests may be conducted by steady state and dynamic computer simulation. It should be noted, however, that impediments to system restoration may occur that are not fully modeled in simulations.

1. Conduct a **Basic Starting Test**.

2. Conduct a **Line Energizing Test**.

3. The OPERATING AUTHORITY will direct picking up sufficient load at the remote end of the isolated transmission system to demonstrate the IOS RESOURCE'S capability to supply the required load identified in the restoration plan, while maintaining voltage and frequency for at least 30 minutes.

Parallel Flow Calculation Procedure Reference Document

Version 1, Draft 1

Approved by OC November 16, 2000.

[See also Appendix 9C1, "NERC TLR Procedure – Eastern Interconnection," Section F., "Transaction Contribution Factor"]

Subsections

A. Introduction
B. Basic Principles
C. Calculation Method
D. Calculation Procedure
E. Sample Calculation

A. Introduction

This Reference Document explains how to calculate the contribution of Network Integration Transmission Service and Native Load on a TRANSMISSION CONSTRAINT under TLR Level 5 (5a or 5b).

The provision of Point-to-Point (PTP) transmission service as well as Network Integration (NI) Transmission Service and service to Native Load (NL) results in parallel flows on the transmission network of other TRANSMISSION PROVIDERS. When a transmission facility becomes constrained, NERC Policy 9C, Appendix 9C1, calls for curtailment of INTERCHANGE TRANSACTIONS to allow INTERCHANGE TRANSACTIONS of higher priority to be scheduled (a process called "Reallocation") or to provide transmission loading relief. An INTERCHANGE TRANSACTION is considered for REALLOCATION or CURTAILMENT if its TRANSFER DISTRIBUTION FACTOR exceeds the TLR CURTAILMENT THRESHOLD, which is typically 5% for MONITORED TRANSMISSION FACILITIES. In compliance with the Pro Forma tariffs filed with FERC by TRANSMISSION PROVIDERS, INTERCHANGE TRANSACTIONS using non-firm Point-to-Point TRANSMISSION SERVICE are curtailed first (TLR Level 3a and 3b), followed by transmission reconfiguration (TLR Level 4), and then the curtailment of INTERCHANGE TRANSACTIONS using Firm Point-to-Point Transmission Service (TLR Level 5a and 5b). The NERC TLR Procedure requires that the curtailment of Firm Point-to-Point Transmission Service be accompanied by the comparable curtailment of Network Integration Transmission Service and service to Native Load to the degree that these three Transmission Services contribute to the CONSTRAINT.

To ensure the comparable curtailment of these three transmission services as part of TLR Level 5a or 5b, the NERC Parallel Flow Task Force (PFTF) has developed a method that allocates appropriate relief amounts to all firm PTP and NI/NL services in a comparable manner. A methodology, called the Per Generator Method Without Counter Flow, or simply the Per Generator Method, has been devised by the PFTF to calculate the portion of parallel flows on any CONSTRAINED FACILITY due to NI/NL service of each CONTROL AREA (CA). The Per Generator Method has been presented to the Reliability Coordinator Working Group (RCWG) and the Market Committee (MC) and both committees have approved the methodology.

The Interchange Distribution Calculator Working Group (IDCWG) has determined that the IDC tool could not be upgraded by the summer 2000 to automatically calculate the parallel flow contributions from NI/NL service. The RCWG then directed the Distribution Factor Task Force (DFTF) to develop an interim procedure to implement the Per Generator Method as an integral part of TLR Level 5 for the summer of Year 2000. A description of this interim procedure is summarized in this reference manual.

B. Basic Principles

The basic principles for curtaining Interchange Transactions using Firm Point-to-Point TRANSMISSION SERVICE curtailment based on NERC Policy 9C, Appendix 9C1, are given below:

1. All firm transmission services, including PTP and NI/NL services, that contribute 5% (the CURTAILMENT THRESHOLD) or more to the flow on any CONSTRAINED FACILITY must be curtailed on a pro rata basis.

2. For Firm PTP transmission services, the 5% is based on TRANSFER DISTRIBUTION FACTORS (TDFs). For NI/NL transmission services, the 5% is based on generator-to-load distribution factors (GLDFs). The GLDF on a specific CONSTRAINED FACILITY for a given generator within a CONTROL AREA is defined as the generator's contribution to the flow on that flowgate when supplying the load of that CONTROL AREA.

3. The Per Generator Method assigns the amount of CONSTRAINED FACILITY relief that must be achieved by each CONTROL AREA NI/NL service. It does not specify how the reduction will be achieved.

4. The Per Generator Method places an obligation on all CONTROL AREAS in the Eastern Interconnection to achieve the amount of CONSTRAINED FACILITY relief assigned to them.

5. The implementation of the Per Generator Method must be based on transmission and generation information that is readily available.

C. Calculation Method

The calculation method is based on the Generation Shift Factors (GSFs) of an area's assigned generation and the Load Shift Factors (LSFs) of its native load, relative to the system swing bus. The GSFs are calculated from a single bus location in the base case. The LSFs are defined as a general scaling of the native load within each control area. The Generator to Load Distribution Factor (GLDF) is calculated as the GSF minus the LSF. Using the present NERC CURTAILMENT THRESHOLD of 5%, the reporting method looks for generation assigned to native load for which the Generation to Load Distribution Factor (GLDF) is greater than 5%. In cases where the Flowgate is considered limiting in the To → From direction, the sign of the GLDF is reversed.

Generators are included where the sum of the generator PMAXs for a bus is greater than 20 MW, including off-line units (e.g., three 9MW generators add up to greater than 20 MW on a bus). Smaller generators that do not meet this criterion are not included. In the calculation process, all tested generators are listed as in-service and their MVA base is set to the PMAX value. SDX information is then applied for generator outages and deratings as applicable. This process may adjust the output of generators that are not intended to participate for an area. In such cases, the generation MVA base value should be adjusted (Percent = 0%) so that those units do not participate. All participation adjustments should be justifiable upon inquiry.

The original MVA base from the seasonal IDC case is not used because it is zero for many non-participating generators, such as nuclear units. The unit output in the case (PGEN) is not used because it may be turned on to a default 1 MW in some instances. The PGEN is not considered a good indicator of the unit's capability. The unit maximum capability (PMAX) is considered a good indicator of the unit ability to contribute.

A set of generation ownership data matches the generators to their Native Load areas. By default, the generator ownership data lists each unit as being 100% contributing to the Native Load calculations of the

control area in which it is contained. There may be situations where the ownership would be less than 100%. Examples include: 1) a merchant generator who has tagged TRANSACTIONS; 2) a generator included multiple times for case modeling situations; or 3) a jointly owned unit. Jointly owned units may have multiple ownership listings to account for the multiple assigned areas. The joint ownership should be less than or equal to 100%.

Unit ownership can go beyond CONTROL AREA bus ownership. Units assigned to serve native load do not need to reside in the native load control area. However, units outside the native load control area should not be assigned when it is expected that those units will have tags associated with their transfers. Although the Native Load calculation has the ability to handle these ownership situations, the CONTROL AREAS and RELIABILITY COORDINATORS must supply the data or the default ownership will apply.

For each generator assigned to a CONTROL AREA'S Native Load, the amount of energy flowing on the CONSTRAINED FACILITY is calculated for the generator-to-Native Load transfer. The reporting is limited to those units that have a GLDF greater than or equal to 5%. The amount of transfer is based on the unit's maximum capability as listed in the base case (PMAX), and a comparison of Native Load level and the available generation assigned to the CONTROL AREA. The available assigned generation does not include small units that do not meet the 20 MW cut off. When the available generation exceeds the load level, it is assumed that not all the generation is participating, and therefore, the PMAX values are scaled down by the load to generation ratio. If available, excess generation that is sold is expected to be tagged. If available assigned generation is less than the native load level, it is assumed that the area may be importing, and therefore the affected units are not scaled (scaling=1.00). Imports are assumed to be tagged.

Summary

If Available Assigned Generation > Native Load, Then Scale Down Pmax

If Available Assigned Generation < Native Load, Then Do not Scale Down Pmax

The amount of Energy on the Flowgate (EOF) that the native load area is responsible for is given as:

$$EOF_{area} = \sum EOF_{gen\ assigned\ to\ area}$$

The Energy on the Flowgate (EOF) for a specific assigned generator with a GLDF > 5% is given as:

$$EOF_{assigned\ gen} = (GLDF)(PMAX_{adjusted\ for\ SDX})(Percent_{Assigned}/100)(Scaling_{Area})$$

D. Calculation Procedure

SDX data requirements

The factor calculation process uses available SDX data to update the current IDC seasonal case. Daily SDX data for transmission outages, generation outages and de-ratings, and daily load levels are applied to the calculation process. The SDX case updates are validated against tables to verify they match the seasonal case branch and generator lists. This is done to avoid process errors and to prevent the accidental insertion on new case data.

Transmission outages are applied by increasing the impedance to "9999" for out-of-service branches. The impedance adjustment is considered equivalent to the branch outage method, and it is preferred since it does not create islanding. Open transmission branches can also be placed back in-service based on SDX data.

Generator outages and de-ratings reported in SDX data are also applied to the case. The IDC seasonal case is initially adjusted such that the MVA base for all tested units is set to the PMAX value. By further adjusting the MVA base value, SDX generation data is then applied to the case to outage or de-rate units.

Daily SDX load levels are applied to the case. This information is used to update each control area's scaling factor. When daily load levels are not available through SDX, the seasonal value will be used as the default. The seasonal value is usually larger than the daily value.

The seasonal case is considered a solvable case. The applied daily SDX data makes the prepared daily case unsolvable. However, for factor calculation, a solved case is not required. Only a valid transmission topology is required.

Phase shifters are modeled as fixed angle. This is judged to be adequate for the present. However, in the relatively near future (when the MECS-IMO PARs are placed in service), ability to handle fixed MW operation will be needed.

Posting of Contribution Factors

The factors will be calculated by MAIN on a daily basis. The factors will be calculated some time after 1300 CST (or CDT) and will be posted before 1400 PM CST. This time was chosen because SDX data updates are required daily by 1300. The SDX data will be captured for those transmission and generation listings, which cross 1401 CST.

A morning calculation may be performed to show the preliminary daily results. This run may be performed about 0800 CST. Specific midday re-runs may be requested by contacting MAIN. A message will be sent to the NERC DFTF after any new report postings. All reports will have a time stamp indicating when they were created. The reports will be posted on the MAIN web site at http://www.maininc.org/firmcurt/index.htm. This site is password protected for transmission use only. RELIABILITY COORDINATORS are expected to be given access to the reports via the RCIS system. Contact MAIN staff if access to the reports is needed. Reports are listed for each reliability flowgate. There is also a summary for each CONTROL AREA. Depending upon browser settings, the page may need to be reloaded/refreshed to view updated reports.

E. Sample Calculation

An example of calculating firm transaction curtailments is provided in this section, assuming that the constrained flowgate is #3006 (Eau Claire-Arpin 345 kV circuit). The GLDFs for this flowgate are presented in Attachment 1. In this example, a total Firm PTP contribution of 708.85 MW is assumed to be given by the IDC.

From Attachment 1, the NI/NL contributions of all CONTROL AREAS that impact the CONSTRAINED FACILITY are listed below:

ALTE = 27.0 MW

ALTW = 41.1 MW

NSP = 33.1 MW

WPS = 26.2 MW

Total NL & NI contribution = 127.4 MW

Total Firm (PTP & NI/NL) contribution = 127.4 MW + 708.85 MW = 836.25 MW

NL & NI portion of total Firm contribution = 127.4/836.25 = 15.2%

PTP portion of total Firm contribution = 708.85/836.25 = 84.47%

Allocation of relief of the CONSTRAINED FACILITY to each CONTROL AREA with impactive NI/NL contribution is given below:

ALTE = 27.0 /127.4 x 0.152 = 3.2%

ALTW = 41.1 /127.4 x 0.152 = 4.9%

NSP = 33.1 /127.4 x 0.152 = 3.9%

WPS = 26.2 /127.4 x 0.152 = 3.1%

Assume that 50 MW of relief is needed. Then those CONTROL AREAS that impact NI/NL contribution and Firm PTP service are responsible for the providing the following amounts of flowgate relief:

Relief provided by removing Firm PTP = 0.845 x 50 = 42.25 MW

Relief provided by removing NL & NS contributions ALTE = 0.032 x 50 = 1.60 MW

Relief provided by removing NL & NS contributions ALTW = 0.049 x 50 = 2.45 MW

Relief provided by removing NL & NS contributions NSP = 0.039 x 50 = 1.95 MW

Relief provided by removing NL & NS contributions WPS = 0.031 x 50 = 1.55 MW

Attachment 1

Native Load Responsibilities

Flowgate #: 3006 **Flowgate Name: EAU CLAIRE-ARPIN 345 KV**

Common Name	Generator Reference System	Generator Shift Factor (GSF)	Percent Assigned	GLDF Gen to Load Factor	Pmax (MW)	Energy on Flowgate
ALTE #364	Avail Assigned Gen: 1,514 Load Level: 1,796 Scaling: 1.000	ALTE_LD Load Shift Factor: -0.097	.	.	.	.
NED G1 13.8--1 CA=ALTE	39000_NED_G1	0.022	100	.1195	113.0	13.5
NED G2 13.8--2 CA=ALTE	39001_NED_G2	0.022	100	.1195	113.0	13.5
Summary	.	.	.	.	.	**27.0**
WPS #366	Avail Assigned Gen: 1,691 Load Level: 1,910 Scaling: 1.000	WPS_LD Load Shift Factor: -0.193	.	.	.	.
COL G1 22.0--1 CA=ALTE	39152_COL_G1	-0.094	32	.0993	525.0	16.6
COL G2 22.0--2 CA=ALTE	39153_COL_G2	-0.094	32	.0993	525.0	16.6
EDG G4 22.0--4 CA=ALTE	39207_EDG_G4	-0.118	32	.0752	331.0	7.9
Summary	.	.	.	.	.	**41.1**
NSP #623	Avail Assigned Gen: 8,492 Load Level: 8,484 Scaling: 0.999	NSP_LD Load Shift Factor: 0.206	.	.	.	.
WHEATON5 161--1 CA=NSP	61870_WHEATO	0.298	100	.0919	55.0	5.0
WHEATON5 161--2 CA=NSP	61870_WHEATO	0.298	100	.0919	63.0	5.8
WHEATON5 161--3 CA=NSP	61870_WHEATO	0.298	100	.0919	55.0	5.0
WHEATON5 161--4 CA=NSP	61870_WHEATO	0.298	100	.0919	55.0	5.0
WHEATON5 161--5 CA=NSP	61871_WHEATO	0.293	100	.0874	57.0	5.0
WHEATON5 161--6 CA=NSP	61871_WHEATO	0.293	100	.0874	57.0	5.0
WISSOTAG69.0--1 CA=NSP	69168_WISSOT	0.266	100	.0601	37.0	2.2
Summary	.	.	.	.	.	**33.1**
ALTW #631	Avail Assigned Gen: 2,337 Load Level: 3,640 Scaling: 1.000	ALTW_LD Load Shift Factor: 0.065	.	.	.	.
FOXLK53G13.8--3 CA=ALTW	62016_FOXLK5	0.147	100	.0819	88.5	7.3
LANS5 4G22.0--4 CA=ALTW	62057_LANS5_	0.116	100	.0506	277.0	14.0
LANS5 3G22.0--3 CA=ALTW	62058_LANS5_	0.116	100	.0505	35.8	1.8
FAIRMONT69.0--3 CA=ALTW	65816_FAIRMO	0.151	100	.0857	5.0	0.4
FAIRMONT69.0--4 CA=ALTW	65816_FAIRMO	0.151	100	.0857	6.0	0.5
FAIRMONT69.0--5 CA=ALTW	65816_FAIRMO	0.151	100	.0857	12.0	1.0
FAIRMONT69.0--6 CA=ALTW	65816_FAIRMO	0.151	100	.0857	7.0	0.6
FAIRMONT69.0--7 CA=ALTW	65816_FAIRMO	0.151	100	.0857	6.5	0.6
Summary	.	.	.	.	.	**26.2**
.	.	.	.	.	.	.
TOTAL Summary	.	.	.	.	.	**127.4**

Reliability Coordinator Reference Document

Approved by the Operating Committee.

March 15, 2006

Subsections

A. System Data Exchange (SDX) — Eastern Interconnection Only
B. TLR Level 6 Declarations

A. System Data Exchange (SDX) — Eastern Interconnection Only

The SDX is the NERC-approved method for submitting operational planning horizon data that is required in NERC reliability standard IRO-004-0, "Reliability Coordination — Operations Planning," Requirement 4. This data is shared throughout the Interconnection(s) for use in available transfer capability (ATC) calculations, the NERC transmission loading relief (TLR) application, which is the Interchange Distribution Calculator (IDC), and power system studies.

In addition, the reliability coordinators in the Eastern Interconnection have agreed that the data is required to be submitted hourly for each balancing authority and transmission operator and received by the SDX system by 20 minutes prior to the reporting hour, in accordance with reliability standard TOP-005-0 (Operational Reliability Information, Requirement 3). Updates to these data may be submitted more frequently. Additional data submittals are required per the guidelines below. It is the intent of the SDX to provide the most current power system data to NERC and reliability power system applications that rely on the data for accurate calculations.

Data Considerations

The information type and format that must be adhered to in an SDX submittal is defined in the NERC SDX Data Specification contained within the NERC SDX User Manual. It is required that the following criteria also be followed when issuing an SDX data submittal.

1. All generation status changes for generation summing to 20 MW or higher on a bus must be reported for each balancing authority.

1.1. Generation elements must be submitted in the PSS/E bus name format and be contained in the most recent IDC application model. The most recent IDC model can be found at the NERC Distribution Factor Working Group (DFWG) Web site.

1.2. This data improves the accuracy of the calculations in the IDC and ATC applications with special emphasis given to the network integration (NI) transmission service and service to native load (NL) responsibility calculation in the IDC.

1.3. Additional generation data may be submitted at the reliability coordinator's desire. The SDX format and application will not prohibit the submittal of generation at all levels contained in the IDC model.

2. All transmission status changes 100 kV or higher must be reported for each transmission operator.

2.1. Transmission elements must be submitted in the PSSE bus name format of the most recent IDC application model. The most recent model can be found at the NERC Distribution Factor Working Group (DFWG) Web site.

2.2. This requirement improves the accuracy of the calculations in the IDC and ATC applications.

2.3. Additional transmission data may be submitted at the reliability coordinator's desire. The SDX format and application will not prohibit the submittal of transmission at all kV levels contained in the IDC model.

3. The daily, hourly, weekly, and monthly loads along with the generation and transmission status changes must be updated as a minimum for each balancing authority and transmission operator as indicated below.

3.1. The daily table, which will be updated daily, will contain seven days of daily peak data beginning with current day. The peak hour of the day will also be specified. This data is required by all reliability coordinators to promote coordination in the Interconnection.

3.2. The data for the hourly table, which will be updated hourly, will be provided for each hour from current hour until midnight tomorrow (i.e., 25–48 hours). But the hourly data set can contain more than 25–48 hours if the reliability coordinator so desires.

3.3. The weekly table, which will be updated weekly, will contain four weeks of peak data beginning with the current week. The data should be submitted using the Monday of each week as the weekly identifier.

3.4. The monthly table, which will be updated monthly, will contain twelve months of peak data beginning with the current month. The data should be submitted using day one of the month as the monthly identifier.

3.5. Generation and transmission status changes, as indicated in the preceding sections, will be updated hourly.

This requirement improves the accuracy of the calculations in the IDC and ATC applications and reliability studies in the Interconnection.

4. The phase shifter tap setting data category will be used to allow those entities with phase shifters to communicate the current tap settings. This information will be used by the NERC IDC to more accurately model phase shifters and their impact on the power system.

4.1. This **data category** is optional to those entities that do not have phase shifter devices and/or are not utilizing the IDC phase angle regulator (PAR) modeling capability.

4.2. When tap positions are communicated to the SDX, they should be communicated in or as close to real time as possible.

4.3. An alternative method would be a direct connection through the ICCP (ISN) to the IDC application.

5. The transformer data category is used to communicate SDX information for transformers.

5.1. If the transformer is modeled using the three winding transformer capability of PSS/E Version 28 or higher, the specific data associated with the three-winding transformer must be provided.

5.2. If using the CSV format, two-winding transformer data is provided using the transmission section of the file, while three-winding transformer data is provided using the three-winding transformer section of the file.

5.3. If using the XML format, two-winding and three-winding transformer data are provided using the same data category, where the appropriate data is provided for each type of transformer.

6. The element group data category is used to communicate SDX information about multiple power system elements using one name or identifier.

6.1. The element groups must be set up in the NERC SDX application database prior to using this data category in outage reporting. The SDX application will recognize the element group and communicate the appropriate element information to the NERC IDC.

6.2. Element groups are typically used to help the SDX user outage several power system elements at one time (i.e., bus outages, transformer/generation combinations, etc.).

6.3. Refer to the NERC SDX application at http://sdx.nerc.mcgware.com/ for element group set up.

7. The SDX uses several status codes to represent the state of a power system element. These status codes are inserted into the SDX data file in the status field for each power system element section. If the status field does not contain one of the following status codes it will create an error for the entry.

7.1. Each SDX user is required to select one of the four following status indicators for each power system SDX entry:

Note: An SDX element will automatically be placed back to the base case status when the element entry is removed from the file submittal or the entry expires.

7.1.1. "O" — Out Of Service for the time stated.

- The NERC IDC application will take the element out of service for the time stated.

7.1.2. "I" — In service for the time stated.

- The NERC IDC application will place the element in service for the time stated.
- It is not necessary to use this status each time an element is put back in service from an outage state. The status is meant to indicate a change in normal status for an element (i.e., normally off line transmission or generation that is put in service for a specified time).

7.1.3. "P" — Partially limited and derated to a level less than its maximum.

- The NERC IDC application will not recognize partially limited units for its calculations.

- This data is very crucial to other power system studies and the MW entry should indicate the available MW output of the unit.

7.1.4. "F" — Forced out of service for the time stated.

- This will cause the NERC IDC to take the element out of service for calculations.

- When this status is selected, the outage is also communicated and posted to the NERC Reliability Coordinator Information System (RCIS) based on the following criteria:
  a. Transmission elements 230 kV and above
  b. Generators 300 MW capacity and above
  c. These forced outages will be posted to the RCIS within one hour of the status change.

7.2. The following additional status indications are available for the SDX user to further clarify the type of SDX entry that is being submitted. These status indicators are recommended to be used when appropriate in place of the required statuses above.

7.2.1. "SS" — Off line but can be brought on-line in three or more hours standby slow.

- This will cause the NERC IDC application to take the element out of service for calculations.

7.2.2. "SF" — Off line but can be brought on-line in one to three hours standby fast.

- This will cause the NERC IDC application to take the element out of service for calculations.

7.2.3. "PS" — The element is pumping and is acting like a load rather than a generator for the time stated.

- This will cause no action in the NERC IDC until a later date and can be used by SDX users for other power system studies.

7.2.4. "SVC" — The element is out of service for the time stated and is a static var compensator.

- This will cause the NERC IDC application to take the generator out of service for calculations.

7.2.5. "HT" — Hot line work — Indicates that there is work that is taking place on the element while it is in service.

- This will have no action taken by the NERC IDC application for their calculations.

8. Direct entry of outages into the IDC application will no longer be supported with the exception of NNL generation status during a TLR Level 5 event. There is a link provided to the NERC SDX system to accommodate outage entry.

9. The most recent version of the NERC SDX Data Specification.

9.1. The most recent version of the data specification can be found in the SDX user manual at ftp://www.nerc.com/pub/sys/all_updl/oc/sdx/SDX_User_Manual.pdf.

9.2. This requirement ensures that all applications depending on this data will be able to recognize the format it is submitted in for use in their reliability calculations.

Transferring the SDX File

In order to ensure all balancing authorities, transmission operators, and reliability coordinators have a means to submit the required SDX data, NERC will provide a tool that will adhere to the most recent SDX data specification for submittal. This is a Web-based tool that requires a NERC-assigned username and password and is only available to signatures of the NERC Data Confidentiality Agreement. Along with the ftp of the comma separated file the http and xml data submittals will be accommodated through the use of defined templates. The most up to date information on the NERC SDX tool is available in the NERC SDX User Manual at ftp://www.nerc.com/pub/sys/all_updl/oc/sdx/SDX_User_Manual.pdf.

Information and guidelines on transferring the SDX file will also be provided at the NERC SDX site for entities that wish to submit the SDX file via another means.

By exception, some entities may have to work through alternative means to exchange data. This must be agreeable to all parties involved.

B. TLR Level 6 Declarations

Introduction

NERC reliability standard IRO-006-0, "Reliability Coordination — Transmission Loading Relief," Attachment 1, "Transmission Loading Relief Procedure — Eastern Interconnection" Requirement 2.8 states:

Requirement 2.8 — TLR Level 6 — Emergency Procedures
2.8.1. The reliability coordinator shall use following circumstances to establish the need for entering TLR Level 6**:**

- One or more transmission facilities are above their system operating limit (SOL) or interconnection reliability operating limit (IROL).
- One or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.

2.8.2. Implementing emergency procedures. If the reliability coordinator deems that transmission loading is critical to bulk electric system reliability, the reliability coordinator shall immediately direct the balancing authorities and transmission operators in its reliability area to redispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until interchange transactions can be reduced utilizing the TLR Procedures or other procedures to return the system to a secure state. All balancing authorities and transmission operators shall comply with all requests from their reliability coordinator.

Purpose

In order for all reliability coordinators to understand how the Interchange Distribution Calculator (IDC) handles the issuance of a TLR Level 6, this document describes the functionality that currently exists and options that the reliability coordinator has when declaring TLR Level 6. This will help ensure the correct action is taken for the given event.

IDC Treatment of TLR Level 6

When a reliability coordinator issues a TLR Level 6 on a flowgate in the IDC the application will search the non-firm and firm e-tags that are in the IDC database for those that affect the flowgate greater than or equal to 5%. It will create two sets of e-tags from this list for the reliability coordinator to curtail:

1. If the e-tag has an active MW amount in the current hour it will be curtailed to zero MW.

2. If the e-tag is planned to start the next hour it will not be allowed to start and will be curtailed to zero for the next hour.

Once this report is created and displayed as the congestion management report, the reliability coordinator will then have three options to move forward with the TLR Level 6:

1. Confirm the curtailment list that contains the non-firm and firm complete curtailments for the current and next hour.

1.1. This will alert the other reliability coordinators that a TLR Level 6 has been declared and that there are curtailments that need to be acknowledged for implementation.

1.2. Once the sinking reliability coordinators acknowledge the curtailments, the IDC will send a reliability cap of zero MW to the balancing authorities on the e-tags for curtailment implementation.

2. Exclude some or all of the e-tag curtailments from the IDC congestion management report before declaring a TLR Level 6.

2.1. This can be done by the issuing reliability coordinator using the "Re-issue/Exclude" option in the congestion management report.

2.2. This will give the issuing reliability coordinator the option of selecting those transactions they wish to exclude from the TLR issuance.

2.3. Once the appropriate e-tags are selected the reliability coordinator will re-issue the TLR and the list of excluded e-tags will appear on the congestion management report but will not be in the curtailed state. The reliability coordinator will then have to confirm the TLR to send the TLR Level 6 notification to the other reliability coordinators.

2.4. Any e-tags that were not chosen for exclusion will be sent out to the other reliability coordinators for acknowledgement and curtailment.

2.5. This option allows the reliability coordinator to declare a TLR Level 6 without implementing e-tag curtailments.

3. Disregard some or all of the e-tag curtailments from the congestion management report while acknowledging the curtailments of a TLR Level 6.

3.1. The sinking reliability coordinator can only do this for each e-tag curtailment after they receive a TLR Level 6 congestion management report from the issuing reliability coordinator.

3.2. The sinking reliability coordinator will select the "Disregard" option for the e-tags they wish not to curtail. This is done in the IDC Acknowledgement screen.

3.3. When the "Disregard" option is chosen and the "Acknowledgement" button selected the IDC will update the congestion management report to identify to all reliability coordinators that the sinking reliability coordinator has disregarded the curtailment and does not plan on implementing it.

3.4. This will prompt the issuing reliability coordinator to initiate a conversation with the sinking reliability coordinator for further clarification on why the suggested curtailment will not take place.

Available Transfer Capability Definitions and Determination

The document titled "*Available Transfer Capability Definitions and Determination - A Framework for determining Available Transfer Capabilities of the Interconnected Transmission Networks for a Commercially Viable Electricity Market*," dated June 1996 is available at http://www.nerc.com/docs/docs/pubs/atcfinal.pdf.

New Section VII approved by Operating Committee

July 16 – 17, 2003

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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Electric System Restoration Reference Document

by the

North American Electric Reliability Council

April 1993

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Foreword

On November 9, 1965, a cascading failure of the electrical system left 30 million people in the dark and caused economic losses estimated at over $100,000,000. Major portions of the northeastern United States and Canada were without electricity. Hundreds of thousands of people were inconvenienced for days. The Federal Power Commission investigated the blackout and recommended ways to ensure that it would not likely happen again. Instead of a mandatory federal program to coordinate electric power, electric utility representatives from 12 regional and area organizations signed an agreement creating the North American Electric Reliability Council (NERC) on June 1, 1968.

The NERC organizational structure provides the mechanism by which electric utilities work together to prevent blackouts. A strength of this structure lies in NERC's ability to call on unmatched expertise and experience from member utilities to serve on its various committees. These people work together to critique the past, monitor the present, and assess the future. NERC establishes and updates Criteria and Guides for reliably operating the bulk electric system. Reliability is NERC's sole mission, and these criteria are based on coordination, cooperation, communication, and commitment.

The NERC and Regional Criteria and Guides present characteristics of a well-planned and operated electric network and describe adequacy and security tests necessary to evaluate its performance. The interconnected electric network is designed and operated such that uncontrolled, widespread interruptions are unlikely. However, building and operating an electric system, which provides 100% reliability is impossible.

I. Introduction

This document provides general guidelines to be followed in the event of a partial or complete collapse of any of the interconnected electric systems in the North American continent. Quick implementation of each control area's restoration plan, compiled in accordance with the suggestions and recommendations contained in this document, will facilitate coordination between member control areas and ensure the earliest possible restoration of the electric system.

It is impossible to predict all the possible combinations of problems, which may occur after a major electric system failure. It is, therefore, the responsibility of system operators to restore the electric system BY applying the general guidelines outlined in this document and in their respective detailed system restoration plans. Mutual assistance between member control areas is highly encouraged.

A. Principles

Each control area should have a readily accessible and sufficiently detailed current system restoration plan to guide in an orderly recovery. System restoration will be aided by communicating to neighboring control areas, and to Regional offices, an accurate assessment of system conditions throughout the restoration process. Communication must be established with power plants, critical substations, and neighboring operation centers. Mutual assistance and cooperation are essential and beneficial to prompt system restoration and to avoid the recurrence of a partial or complete electric system collapse.

In the event of an electric system collapse, each control area should use the following as guiding principles for the restoration process:

1. Take immediate steps to initiate internal system restoration plans.
2. Restore a high percentage of internal load in as little time as possible.
3. Provide assistance to any and all control areas as system conditions allow.
4. Supply neighboring control areas and Regional offices with information on electric system status.
5. Coordinate with neighbors the reconnection of control areas and/or islands.

B. Plan Elements

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 the strategies is seldom practical. Simulation testing of plan elements, major plan sections, or the overall plan are essential preparations toward readiness for implementation on short notice.

Control area restoration plans include the following elements:

1. Philosophies and strategies for control area restoration
2. Selection of critical alarms from the alarm information available
3. Identification of the relationships and responsibilities of the personnel necessary to the restoration
4. Identification of blackstart resources including:
    a. generating unit resources
    b. sufficient fuel resources
    c. transmission resources
    d. communication resources and power supplies
    e. mutual assistance arrangements

5. Contingency plans for failed resources
6. Identification of critical load requirements
7. Provisions for training of personnel
8. Provisions for simulating and, where practical, actual testing and verification of the resources and procedures
9. General instructions and guidelines for:
   a. system operators
   b. plant operators
   c. communications personnel
   d. transmission and distribution personnel
10. Provisions for public information

The body of this document contains more details on items to be considered in the restoration process, which may be used in the development or review of individual control area system restoration plans.

C. Priorities

Establishing priorities can be subjective and even change from one incident to another or one area to another. Starting units with blackstart capability and providing auxiliary power to units that have just been shut down is clearly a very high priority.

The following actions for system restoration should be considered by each control area and assigned proper sequence and priority:

1. Stabilization of generating units
2. Restoration and maintenance of intra- and inter-system communication facilities and networks
3. Assessment of control area condition and bulk electric system conditions
4. Contact local police and fire departments concerning the extent of the problem
5. Contact with public information agencies to request the broadcasting of pre-distributed appeals and instructions
6. Restoration of units with blackstart capability
7. Providing service to critical electric system facilities
8. Restoration of the control area's transmission system
9. Connection of islands taking care to avoid recurrence of a partial or complete system collapse and equipment damage
10. Restoration of service to critical customer loads
11. Restoration of service to remaining customers

If it becomes apparent that the emergency is a Regional one, the focus of restoration action should shift from individual control area priorities to bulk electric network priorities. Giving priority to a neighboring system's generation and/or load may be necessary in order to benefit the rapid restoration of the bulk electric system. As generation and transmission facilities become available, systematic restoration of network load should proceed using established priorities.

D. Responsibilities

Each control area should train associated personnel (system operators, power plant operators, etc.) in the implementation of its detailed internal system restoration plan. Non-control area electric utilities should prepare a plan, in cooperation with their responsible control area, designed to assist and coordinate with the control area's plan. This applies to cogeneration facilities and independent power producers. Where appropriate, a copy of these plans should be on file at the

Regional offices. System restoration plans should be verified by as much simulation testing as possible, although actual physical testing is highly encouraged where feasible. Simulation also can help determine the feasibility of parallel activities, sequential activities, and avoidance of unnecessary loss of equipment life. Control areas should report significant testing activities of system restoration plans to their Regional Reliability organization and summarized Regional activity should be presented to the NERC Operating Committee.

II. Conditions That May Result in Major Area Blackouts

A. Definitions

A blackout is a condition where a major portion or all of an electrical network is de-energized with much of the system tied together through closed breakers. Any area whose tie lines to the high voltage grid cannot support reasonable contingencies is a candidate for a blackout. The area will become electrically isolated if a *critical contingency* should occur. The identification of these areas, as indicated in Figure 1, should be a high priority for minimizing blackouts.

Separation of an island from the grid will take place under two general scenarios:

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

System separations 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.

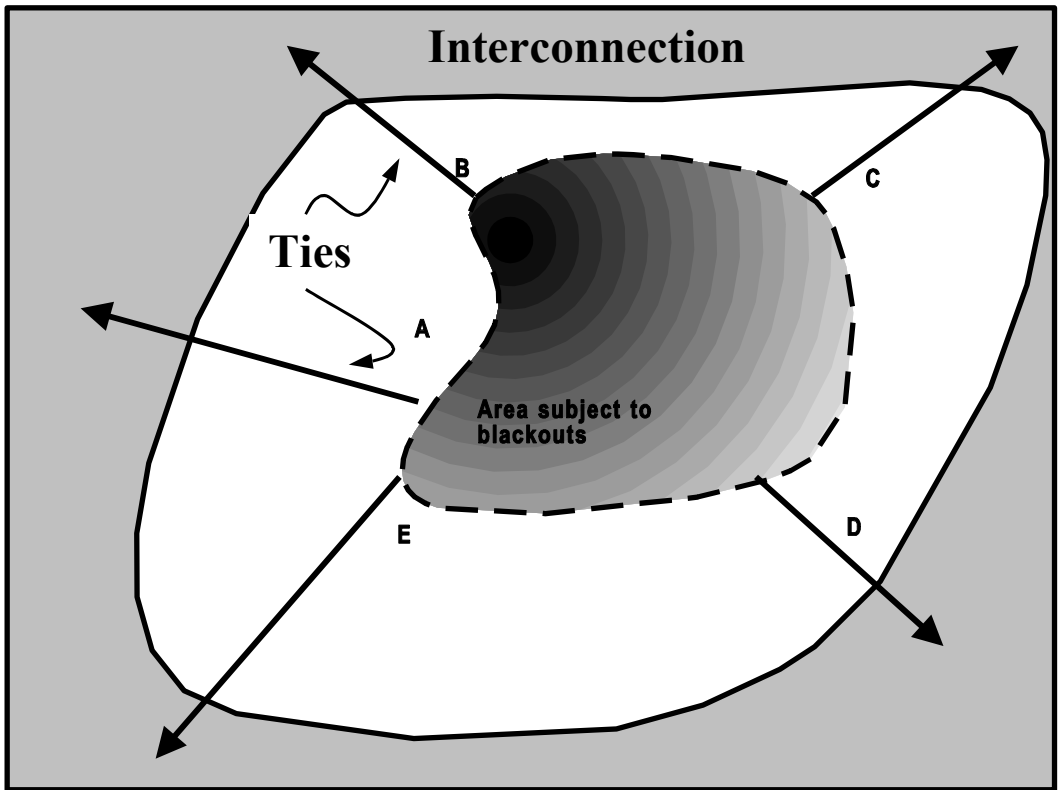
B. Separation Due to Dynamic Instability

The transmission system should be able to sustain any single contingency without loss of load. If the steady-state response to a single contingency does not drive loadings beyond facility capabilities, it should be expected that the dynamic response to the single contingency will be stable. The damping of the system should be adequate. Except in very special cases, the steady-state response will be more constraining than the dynamic response to a single contingency. For this reason, separations due to dynamic instability are typically initiated by multiple contingencies such as loss of corridors, several transmission circuits, several generating units, or delayed fault clearing. These contingencies were referred to before as a *critical contingency*.

Following the *critical contingency*, a tie line of Figure 1 will approach an out-of-step condition. Cascading of the other ties will isolate the area from the grid. There will be no time for operator intervention. If possible, isolated areas should be automatically established with good generation to load ratios. Early detection of unstable conditions may be possible in some parts of the system. In these cases, selective use of transfer trip relaying can isolate an area with a favorable generation to load ratio. In general, there may be no clearly defined area that will separate. In such cases, the extent of the affected area will only be known after-the-fact.

If the isolated area is generation deficient, underfrequency relays should shed the necessary load to match load and generation in the island, and the operation should become stable at or near 60 Hz. If not, load should be shed to restore stable operation near 60 Hz. If the isolated area has excess generation, the total area generation must be reduced immediately to approximate the area load for 60 Hz operation. When possible, schemes for islanding as well as frequency correction programs should limit the consequences of stability contingencies. Controlled islanding action is preferred to blackouts.

Figure 1 – Area isolated from the Interconnection



C. *Collapse Due to Steady-State Overloads and/or Voltage Collapse*

The system just prior to a blackout may not be dynamically unstable but in an overloaded condition. At such loadings, the collapse may come about due to damage to thermally overloaded facilities, or circuits contacting underlying facilities or vegetation. When an overloaded facility trips, other facilities will increase their loadings and may approach their thermal capabilities or relay trip settings. There may be some time to readjust system conditions (generation shifts, load shedding, transfers, etc.). If not, the overload will lead to electrical isolation.

Voltage collapse, as currently defined by the IEEE Working Group on Voltage Stability, is the process by which voltage instability leads to the loss of voltage in a significant part of the system. This condition results from reactive losses significantly exceeding the reactive resources available to supply them. Circuits loaded above surge impedance loadings and reduced output of shunt capacitors as voltages decline can lead to accelerating voltage drops. It is possible that impending voltage collapse can be detected by slowing dropping voltages in an area of concern. However, heavy use of shunt capacitors or reactors can maintain near normal voltage up to the point that voltage support resources run out. Thus, voltage collapse can look like both a steady-state problem with time to react and a problem where no effective operator intervention is possible. The NERC *Survey of the Voltage Collapse Phenomenon* provides more insight into this problem.

It is very hard to predict the area that will be affected or electrically isolated from the grid. Adequate models of load variation with voltage are not available, and there is an undeterminable variety of sequential circuit operations that can lead to wide area collapses.

The characteristics of a steady-state voltage collapse are different from those of a separation due to dynamic instability:

1. The *critical contingency* may be a single contingency if a heavily loaded circuit exceeds its capability or gets close enough to material objects to flash over.
2. The process of voltage collapse is usually slow enough to permit operator intervention to reverse the process if adequate information and resources are available.

The prevention of the voltage collapse is usually accomplished by shedding load or by rapid generator response to quickly relieve the overloads. These remedial actions do not form an electrical island as may be attempted for dynamic stability problems.

D. Blackout Causes

Blackouts originate from power system disturbances resulting in loss of service to all loads within an area. System disturbances are reported when they turn into large service interruptions.

The DOE criteria for reporting major bulk power system disturbances for systems with peak load greater than 3,000 MW is:

1. Loss of 300 MW load for greater than 15 minutes
2. Loss of service to over 50,000 customers for more than three hours

In addition, CIGRE Study Committee 39, Group 05 AOperational Performance of Power Systems≅ has performed a worldwide survey on power system disturbances. The severity of the disturbances was measured in terms of System Minutes:

Degree 1 X From 1 to 9 System Minutes
Degree 2 X From 10 to 99 System Minutes
Degree 3 X From 100 to 999 System Minutes
(One System Minute is equivalent to an interruption of the total load of a system for one minute.)

The CIGRE study committee only reported the main cause of disturbances. For instance, a system disturbance resulting from a circuit fault and a subsequent failure of a breaker to clear would be reported as caused by breaker failure if the system should have been able to withstand the original fault. The main causes are listed as follows:

Faulty conventional protection and control equipment
Faulty special protection (i.e., generation rejection scheme)
Lightning
Weather other than lightning
Solar magnetic disturbances
Faulty high-voltage equipment
Personnel error
Other causes
Unknown

There were 295 disturbances reported for the period 1982 to 1989. Of these, there were 271 disturbances with an identified main cause. Over 22% of the disturbances were caused by lightning, other weather and solar magnetic disturbances, over 47% were caused by faulty equipment, and 7% were the result of personnel errors.

Since power system disturbances appear to occur at random, remedial schemes should be considered when possible and appropriate. These schemes will detect the disturbance early enough to avoid the total outage of an area.

III. Determine Blackout Extent and System Status

A. *Communication*

A functional communication system is critical for the assessment of the extent of a blackout and determining the status of generation and transmission facilities. Utilities should review their communication systems, regardless of whether it is a private carrier (telephone company) or electric utility owned. The assessment is essentially the same for a private carrier or electric utility owned. It should be determined that there is an adequate power source to the communication equipment in order to handle the duration of the blackout conditions. Battery capacity, standby generation availability, enough fuel, or adequate refueling plans also need to be studied. For utilities sharing communications equipment and networks with their neighboring utilities, both users should assess the impact of equipment failure.

B. *Customer Calls*

In the early stages of system restoration, utility dispatch centers will be bombarded with phone calls from employees and customers. From the utilities perspective, continual calls inquiring into the status of service serves no useful purpose. In fact, continual customer calls may be a detriment by degrading the public telephone system to a point that it is not functional for the utility. Some of the ways of mitigating problems are:

1. Automatic dialing system to notify employees of the status
2. Immediate notification of customer service representatives
3. Public appeal to limit phone system use
4. Priority call system for utility dispatchers' phone systems

Dispatch centers that do not handle customer calls should consider establishing a center or desk for communicating with governmental and public agencies. Dispatchers will then be able to focus directly on operations.

C. *RTU Operation Without AC Power*

In order to be functional in a blackout, RTUs should not be dependent on ac power. RTUs, in general, are designed to be powered by dc from the station battery. The RTU interface equipment with the telephone system, such as amplifiers and equalizers, also should not use ac-powered equipment. Telephone companies generally try to use ac-powered equipment throughout their system, but utilities have a special need. Utilities should include periodic monitoring of RTU communication equipment as part of their routine inspections to ensure that it is not dependent on ac power.

D. *Units Available for Service*

The system restoration sequence and timing will be directly impacted by the various sizes, types, and state of operation of the system generating units prior to the blackout. The operating fossil, hydro, and combustion turbine units prior to the disturbance will likely be the most desirable units for the restart effort with the non-operating blackstartable units included among this group. The system operators will need to know throughout the restoration process the status and

availability of the system generating units. They also need to be alert to the influences of the weather and temperature and understand their potential to alter the availability of these units as well as their fuel supplies.
Determining the proper sequence for returning generating units to service also requires the gathering of known facts about the specific units beforehand. Having a tabulation of the individual unit characteristics and capabilities will be beneficial when selecting the order and fit of the units for the restoration sequence. This data will need to be compared to the actual serviceability of these units soon after the disturbance has occurred, with special emphasis placed on defining any changes to ramp rates, restart times, minimum or maximum load and var generation, or damage that occurred which might constrain unit operation. As many units as possible should be startable in parallel, although some will have to be done sequentially. Connected loads at plants and along circuits between plants also must be taken into consideration.

Auxiliary power should be restored to the generating sites as soon as possible to improve their availability. Relatively short delays in restoring auxiliary power can result in delays of several hours (or even days) in restoring the affected units. Station emergency generators and backup batteries may provide power for only the most essential safety systems but cannot be counted on as a source for a unit start-up.

E. Units Operating With Local Load

Units that have become isolated or islanded will not have the stability they would have if the system were normal. Units that have separated from the system, supplying their own auxiliary load or local area loads, will be at greatest risk of having frequency control problems if the actual unit load is less than the minimum load for the unit. Adding more station or distribution load or substituting fuels may increase the stability of the unit. However, any load added should be in small increments to prevent the unit from tripping and to better control the voltage and frequency fluctuations.

In some cases, the system operator may not be able to identify units that have separated from the system but are continuing to supply some load either to their own station auxiliaries or local areas. These units may appear to have tripped off-line based on observations of system control center generation stripcharts, frequency meters, load meters, and the like. Knowledge of the size and locations of these islands needs to be communicated to the system operators to enable them to choose the best strategy for the restoration effort and unit stabilization. When islanded areas can be identified, they should become the basis for connecting with adjacent islands as they become available.

F. Units With Blackstart Capability

The sources of start-up or cranking power, regardless of their type, need to be of adequate capacity to provide for the largest anticipated load plus any line charging requirements. For a remote combustion turbine or hydro site providing blackstart capability to another unit, line voltage between the source and load should be monitored and controlled close to the normal operating values. Adding shunt reactors may be necessary for var control if the reactive limits are exceeded on the generator(s) providing the cranking power.

At blackstart sites having multiple sources with which to provide remote cranking power, parallel unit operation will be required if the load is more than the output of one unit. Controlling these multiple units at no-load and then combining them into a single synchronized source will be necessary. As the cranking power path leaves the blackstart site, possibly entering substations or switchyard, breaker configuration will need to be examined to prevent unwanted loads from using power intended for units to be started or causing a trip-out of the blackstart sources.

G. Scrubbers Availability After a Period Without Power

The waste stream, thickening and transport sections of a "wet" flue gas scrubbing system, will be susceptible to rapid sludge thickening and solids set-up upon loss of power. For system equipment such as tanks, piping, rake drives, and pumps installed in unheated or outdoor locations, particular attention should be given to their sensitivity to low temperatures and freezing if not kept heated or drained of liquids. Spray lines and spray pumps would be recommended for draining and flushing as well. Creation of a solids settling time-line and a time-temperature curve might well serve as guidance to develop procedures.
Am "dry" scrubbing system will typically have residual fluids and solids in its treatment/sorbent slurry, the atomizing system and recycle lines. A flushing and draining of these sections would be recommended even if installations are in heated areas. The ash transport lines for the associated bag house should be purged as well.

The power requirements to operate a unit's scrubber system can demand a significant portion of the total station auxiliary power even under normal conditions. At some power stations, scrubbers can consume as much as 30 MW. During a system restoration, especially in the early stages, the power to operate a scrubber may better be directed to serving customer or other system needs. Operating temporarily without some portion of environmental controls also may be in the public's best interest. An examination of the specific effects and risks of shifting these power uses to the customer should be considered.

H. Nuclear Plant Status

When a nuclear unit trips off-line and simultaneously the auxiliary power from the outside sources is lost, their site emergency generators are designed to start and supply the emergency or safeguard busses with power. Off-site power should be restored as soon as possible even though the unit start-up will be delayed. Upon the availability of off-site power to the non-safeguard busses, and assuming no equipment damage has taken place nor any radioactive leakage has occurred, a restart of the unit is possible.

Nuclear units require special treatment. NRC start-up checklists generally do not permit hot restarts and their diesels would not be permitted to supply auxiliary power to other stations. Nuclear units that are taken off line on a controlled shutdown can be restored to service in about 24 hours; more likely 48 hours after a scram. While restoring off-site power to nuclear units requires attention, restoring power to service area load will normally need to be without the help of nuclear units.

I. Neighboring Systems

In today's operation of generation and transmission systems, few utilities are autonomous. Knowledge of the neighboring utilities' status can enhance restoration through pooling restart sources, sharing reserves, and interconnecting transmission. Utilities should have functional communications to gain timely knowledge of the overall system status. Data links for system conditions in neighboring systems will aid in limiting the amount of verbal communications required. Special coordinating efforts will be necessary for facilities that are jointly owned or operated between two or more utilities.

J. Personnel Availability

System restoration requires utility personnel to complete an enormous amount of tasks in a relatively short time (less than 24 hours). It is essential for utilities to promptly get appropriate

off duty personnel notified to report to duty. Automatic notification systems can provide system and plant operators necessary relief of this burden. For effective use of extra personnel, utilities should consider defining responsibilities in advance of the event. Standing instructions for personnel expected to be involved should be to report to a designated site under blackout situations on their own initiative. Consideration must also be given for rotating personnel to keep fresh system and plant operators. Lists of contractors and the location of special tools and equipment should be available.

K. Transmission Breaker Status and Connectivity

After a system has blacked out, the system operators should perform a quick survey of the system status. Circuit breaker positions will not provide a reliable indication of faulted versus non-faulted equipment. Breakers will be found open from:

1. Permanent faults (storm related or equipment degradation), which may have initiated the system shutdown
2. Out-of-step conditions: As the system collapses, power flow on some lines may swing through the impedance characteristics of the line relays and trip the line. These lines will be usable in the restoration plans.
3. Temporary faults: As the system cascades into shutdown, some lines may overload, allowing the conductor to sag into underbuild or other right-of-way obstructions. After the fault is cleared and the conductor has cooled, the conductor will regain adequate clearance and will be serviceable.

Breakers can be found in the closed position, but the associated transmission facility is faulted. If the system blackout is storm-initiated, this condition is quite possible. The storm can continue to damage equipment after the system is de-energized.

Utilities operating in cold weather should be concerned about breakers= serviceability. In cold weather, breakers with leaks tend to leak more. After prolonged periods without ac power to compressors and heaters, enough pressure may not be available for circuit breaker operation. SF6 gas may condense into a liquid causing the breaker to lock out until heaters and compressors are restored. Clearly, station service should be restored as soon as possible.

L. Transmission Facilities Unavailable for Service

Because breaker positions cannot be relied on as an indicator of facility availability for service, the system operator should rely on field verified data (such as oscillographs) to determine whether or not equipment is faulted. Also, equipment with neutral connections, such as reactors, transformers, and capacitors, may be locked out from the neutral overcurrent conditions during system shutdown. These facilities may be in perfectly serviceable condition.

M. Station Battery Effective Availability

The station battery is one of the most critical pieces of equipment in the restoration process. Most utilities have standards for specifying the battery size. A common battery standard is to have enough battery capacity to handle an 8 to 12 hour outage of ac power to the battery chargers and still be able to serve all of the following:

1. All normal dc loads
2. The largest credible substation event at the beginning of the 8 to 12 hour period
3. One open-close-open operation on each substation device during the 8 to 12 hour period with some margin

The main concern with this specification is whether a blackout event will result in a greater initial dc load than the largest substation event. Also, will more than one operation be needed on each device before ac is restored to the substation?

Utilities may periodically test station batteries based on a substation theoretical load profile in a system blackout, not based on design criteria or manufacturer specifications. Testing based on design criteria of manufacturer specifications can mislead utilities as to their actual battery performance. Also, proper, routine battery maintenance is essential to battery performance in emergencies.

Utilities should periodically review the station battery loads to check for added loads, such as dc lights or dc heaters, that the battery was not designed to handle without an ac power source.

N. Expected Relay System Reliability

Most relay systems will remain reliable and secure during restoration, provided there is adequate fault current available to activate the relaying. The most questionable relay reliability issues come from reclosing relays. Utilities should review their restoration plans for impacts of inadvertent reclosure of breakers during energization. Restoration plans also should be reviewed for reclosing schemes that allow reclosing in a manner that is only suited for normal operation. Some examples are:

1. Station hot bus-dead line reclosing requires the main bus to be hot before a transmission line is reclosed. In a blackout, this scheme may prohibit energizing from a blackstart generator into a transmission station.
2. Peaking plants that tap a transmission line may require a hot line before allowing closure to the line. If this is a blackstart generator, energizing of the line may be prohibited until the relay is bypassed.
3. Motor operated air-break switches that may inhibit circuit restoration.

O. Underfrequency Relaying Load Status

Utilities should make the status and control of underfrequency relays available for the system operator through SCADA. The underfrequency relay operation indication should be identified and segregated by trip frequency so that the system operators know what underfrequency protection has activated and what is remaining.

Any block restoration of underfrequency load shed by underfrequency relays should be sequenced so that the entire block of load is not restored simultaneously, resulting in re-activating underfrequency, or in the worst case, causing the system to shut down again. Distribution circuits with capacitors and/or underfrequency relaying may want to be energized later in the restoration process to avoid voltage problems or automatic trips.

During much of the early stages of system restoration, customer service may be rotated, giving more customers an opportunity for some amount of service. The SCADA system load shed program should be designed to allow previously restored underfrequency load to be shed, and shed load restored.

P. Generators Tripped by Underfrequency

A unit separated from the system due to an underfrequency trip may have islanded and continue to generate power for its station auxiliary load. With no system load on the generators, the station

auxiliary demand will be quite small, and the steam generators output may be difficult to control. Immediate load addition may be required to keep the steam generator from tripping or having the steam turbine trip out on overspeed. Other units may be able to operate indefinitely on their auxiliary load.

For the units tripped and unable to maintain generation for their own auxiliary load, a complete restart would be necessary. Restart could commence with the return of station auxiliary power from an external source.

IV. Restoration of Auxiliary Power to Operable Generation

A. *Evaluate Transmission System Status*

A system blackout will generally cause much initial confusion and create a large number of SCADA alarms and reports. Efforts should be made to ensure that only essential alarms are given to operators under these and other emergency situations. Before generating units can be restarted, an accurate picture of the transmission and generation system should be developed. The first step of the restoration process should be an evaluation of the transmission system. Energy Management System (EMS) SCADA indications should be confirmed by dispatching field personnel or verify equipment status from other sources as required. This EMS SCADA data will be used during the restoration process and must be accurate if the process is to be successful. All known and/or suspected transmission damage should be identified. Work can then be initiated on damaged transmission facilities that are involved in the blackstart process, to either isolate or repair the damaged facilities, or to use alternate paths.

B. *Evaluate Generation Resources*

Generation resources in any system are constantly changing. This will be especially true following a partial or complete system blackout. The units that were on line during the event are now off line and in an unknown condition. Plant personnel should begin an immediate assessment and, as soon as possible, communicate unit status to the control center. This must be complete before the full restoration process can be initiated. This information will be used to develop a blackstart process based on actual unit availability. Enough units must be provided with auxiliary power to assure capacity to serve all customer load.

C. *Fuel Supply Considerations*

In a blackout event, especially a wide spread event, natural gas transmission facilities should be considered for priority power restoration if they are required as a fuel source for generation. Most, if not all, of those facilities do not have on-site emergency power. Transmission paths supplying start-up power for generating units also should support fuel delivery to those units.

D. *Blackstart Process*

Each system should have a blackstart plan including specific transmission and generation procedures to implement that plan. In an actual system blackout, the generation and transmission resources could be significantly different than anticipated. The primary focus of a restoration process is to connect available generation to a start-up power source. The information accumulated during the transmission system and generation resources evaluation should be used to develop a blackstart process utilizing actual available resources. The process should include the following:

1. Establish off-site power for nuclear units, both those that had been operating and those already off line. This is required without regard to using these units for restoring load.
2. Units with blackstart capability should begin the restart process for use in supplying start-up power to other units.
3. Priority access to start-up power should be given to hot units that can be returned to service immediately.
4. Priority access to start-up power also should be given to other units that can be started within a few hours.

5. Consideration should be given to connecting shunt reactor devices to help stabilize generating units being brought on line.
6. Transmission corridors for supplying start-up power should be identified and switching procedures determined, taking extra care to isolate damaged facilities.
7. Units without blackstart capability should be prepared to begin the start-up process when start-up power becomes available.
8. Transmission system corridors to support the start-up process should be established but not energized until needed.
9. As units with blackstart capability come on line, *energize* appropriate transmission system corridors supplying start-up power for units that are ready to return to service.

E. Procedure Testing

For blackstart units to achieve their maximum benefit, they should be tested periodically under realistic conditions. In addition to demonstrating that the units can in fact be started using designated facilities, this also provides training for the people involved with the process. Similar testing and training also is needed for units with load rejection capability. Isolating these units from the system when conditions permit and using the actual sources to start them is a worthwhile and revealing exercise. Problems that could seriously impact an actual restoration can be revealed under controlled conditions and corrected before they can impact an emergency. Similar testing and training also is needed for units with load rejection capability.

V. Preparation for the Transmission System Restoration

A. Restoration Switching Strategies

After determining the extent of the blackout and assessing the status of system equipment, the switching operations necessary for system reintegration represent a significant portion of the restoration process. Depending on the specific utility's requirements, there are two general switching strategies, which may be used to sectionalize the transmission system for restoration. The first is the "all open" approach where all circuit breakers at affected (blacked out) substations are opened. The second strategy is the "controlled operation" where only those breakers necessary to allow system restoration to proceed are opened.

The "all open" strategy can be effectively accomplished by local station operators or by automated EMS supervisory control. This approach has the advantage to the system operator of presenting a simpler and safer configuration to re-energize. Only breakers involved in the restoration process will need to be closed. System collapse or voltage deviations due to inadvertent load pickup or circuit energizing are less likely to occur. Drawbacks of the "all open" approach are that restoration time may be longer and more stored energy is required for the greater number of breaker operations. Stored energy in the form of compressed air or gas, springs, or station batteries is used to operate the breaker mechanism. Unless this energy is lost due to leakage or discharge due to operations during the blackout event, circuit breakers should be capable of one open-close-open operation without ac station service.

The Acontrolled operation≅ switching strategy imposes less (stored) energy requirements since breakers not involved in the initial sectionalization and restoration remains closed. However, the system operator must be continually aware of the isolation between the restored and de-energized systems. Studies should be conducted to examine steady state and transient voltage response if multiple transmission circuits are to be energized by the "controlled operation" strategy. Either strategy requires an extensive amount of switching operations, except that "controlled operation" will hopefully postpone some breaker operations until after station service is re-established.

B. Cold Weather Switching Concerns

In addition to the limited number of breaker operations during a blackout, switching operations can be further compromised following an interruption in cold weather. The proper operation of many transmission breakers (particularly air-blast and SF6) depends on maintaining the proper temperature and pressure within the breaker. This is normally accomplished by heating elements and compressors supplied by ac station service. A cold weather interruption reduces the time window for normal breaker conditions (as short as thirty minutes), after which operation may be blocked by electrical interlocks monitoring the breaker pressure. Although most breakers can be operated manually, this method normally requires the breaker to be de-energized for safety and restricts switching operations. If manual operation is required for energized breakers, breaker misoperation or damage may occur.

C. System Sectionalizing

Regardless of restoration switching strategy, system sectionalizing to disconnect load and capacitors from the transmission system is generally desirable. Unless load pickup is required when energizing transmission circuits for voltage control, loads should be disconnected and restored in small blocks for system frequency control. Opening of station and controlled distribution capacitors may help prevent high voltage and generator underexcitation conditions aggravated by charging current of unloaded transmission circuits. Shunt reactors are ideal

candidates for controlling high system voltage if studies show their use acceptable under weak system conditions. Transformer tap positions, especially load tap changers under automatic control, should be reviewed and moved if substantially off nominal. Generator voltage regulators should be in service to limit voltage deviations prior to load pickup or circuit energizing. Restoration of several subsystems in parallel and then tying them together may shorten the restoration process if manpower and facilities are available.

D. System Assessment

In preparation for an actual restoration, the effort to ascertain faulted system equipment will detract from the restoration process. Many transmission circuits may trip due to out-of-step relaying or temporarily sag and trip during the system collapse. These circuits may be serviceable for restoration, however, system operators should exercise care to avoid closing into a fault when energizing the transmission system. If possible, field personnel should check relay flags of tripped transmission circuits before energizing. Any verifiable failures must be factored into the restoration.

A utility restoration plan incorporating either the “all open” or “controlled operation” switching strategy must consider the impact of substation equipment availability following a blackout. Inoperable or failed equipment at key substations will require additional switching operations and may significantly delay the restoration effort. Utilities that rely on automatic restoration equipment at unattended stations not controlled by supervisory control must take operation of this equipment into account in developing restoration plans.

VI. Restoration of the Transmission System and System Loads

A. *Transmission Restoration*

1. Voltage Limitations

During restoration, the bulk power system should be operated so that reasonable voltage profiles (within the range 90% to 110% of nominal) can be maintained. Where possible, voltages should be maintained at the minimum possible levels to reduce charging currents.

When energizing transmission lines, care must be taken to make sure that nearby generators are on automatic excitation control and that enough Mvar reserve (or margin) is available at the generator to absorb the line charging. If the generator's underexcited capability is exceeded following the line energization, a voltage runaway situation may arise.

Once a line has been energized successfully, it is best to energize some local load to reduce the voltages. Successive energization of a line followed by that of a load will be a good strategy to control the voltages to within acceptable ranges. The system operators should attempt to balance the reactive requirements using line charging, and loading of shunt capacitors, reactors, and unit Mvar reserve capabilities. Transmission shunt capacitor banks should be removed from service to prevent high voltage until sufficient load has been re-energized. Shunt reactors should be placed in service when initially restoring the system to help reduce system voltages. Static var compensators and condensers under automatic control should be placed in service as soon as practical. Voltages need to be continuously monitored on all the transmission circuits, particularly those that provide inter-area ties.

2. Synchrocheck Interconnection Relay Schemes

Automatic reclosing relays should initially be disabled in order to prevent premature, uncontrolled, automatic reclosure of individual interconnections. Isolated areas should be synchronized using the highest voltage line available. This procedure is desirable because of the lower impedance and higher relay load ability of the higher voltage lines. However, possible overvoltages or special considerations could prompt the use of lower voltage lines.

Control areas, which share common transmission or generation facilities, must develop prearranged plans for the priority operation of these facilities during restoration. Interconnection should only be attempted at a generating plant or at a station with a synchroscope. Substations, which have the capability of synchronizing two systems, which are isolated, should be identified and included in each system restoration plan.

Where possible, field personnel should be used to verify breaker positions. When synchronizing, both phase angle across the breaker and the voltage on each side of the breaker should be measured. If possible, the phase rotation should be stopped and the phase angle reduced to ten degrees or less before interconnection is made.

3. Transmission Stability

Circuit energizations should be performed in a deliberate manner, checking the status of all associated facilities before and after energization. The system operator should aim low on voltage when energizing circuits to reduce charging currents. The energized

transmission must be monitored to control facility loadings and voltage conditions. Minimize the number of switching operations because: (1) excessive switching increased restoration time, and (2) until station service is restored to a substation, the breakers at that station can be operated only a relatively few times before they become inoperative due to loss of stored energy. Only energize transmission lines that will carry significant load. Energizing extra lines will generate unwanted Mvars.

Prior to energizing a line section, the system operator should attempt to keep the voltage on the source bus below its nominal value. Open shunt capacitors and close shunt reactors before re-energizing transmission lines. If minimum source requirements have been established for a transmission line, the system operator must ensure that those requirements have been met before energizing the EHV line. Minimum source requirements address the concerns associated with:

a. Steady-state overvoltage caused by excessive var supply from the capacitive rise of EHV lines and aggravated by harmonics from transformer saturation.
b. Transient overvoltage caused by traveling wave phenomena.
c. Dynamic overvoltage caused by transformer magnetizing inrush and aggravated by harmonics from transformer saturation.
d. Reduction in proper relaying protection reliability due to insufficient fault current and overvoltage failure of EHV equipment.

Where possible, ac load flow analysis should be used to examine steady-state voltage levels, and switching surge studies should be used to identify transient problems. These must be representative off-line studies prior to the incident until practical real-time analysis is developed.

If an EHV line is to be energized by closing the breaker on the low side of the transformer, consideration should be given to adjusting the tap changer to its studied position or in the absence of a specified setting to its lowest EHV tap setting. On an open-ended EHV transformer that will be energized with an EHV line, adjust the tap changer to the studied tap position, to its normal or midpoint position, or to match the energized line voltage. Ferroresonance may occur upon energizing a line or while picking up a transformer from an unloaded line.

4. Fault Availability for Proper Relay Operation

Low available short circuit current can hinder the performance of protective relaying. Because of a higher likelihood of overvoltage, and thus system faults during restoration, proper relay protection is imperative to prevent recollapse of a weak system. Primary and backup EHV relaying should be in service on all lines being returned to service. The system operator should assure that adequate underlying transmission capability is electrically connected at the interconnection point to provide adequate fault current (relay protection). Impedance relays that do not have out-of-step blocking may trip lines due to power swings during restoration.

5. Transient Problems in Energizing Transmission

Various factors affect the transient stability of a system, such as the strength of the transmission network within the system and of the tie lines to adjacent areas (if any), the characteristics of the generating units, including the inertia of the rotation parts, and the electrical properties such as transient reactance and magnetic saturation characteristics of the stator and rotor iron. The stronger (i.e., lower source impedance) and the more numerous the lines on a bus, the less severe the energizing transients become. In

addition, connecting shunt reactors to the line especially at the remote end of the terminal to be switched, will lower the energizing voltages.

Severe overvoltages resulting from switching surges may cause flashover and serious damage to equipment. Switching transients are fast transients that occur in the process of energizing transmission line and bus load capacitances right after a power source is connected to the network. The transient voltages or switching surges are caused by energizing large segments of the transmission system or by switching capacitive elements. The switching transients, which are usually highly damped and of short duration, in conjunction with sustained overvoltages, may result in arrestor failures.

Transient overvoltages are not usually a significant factor at transmission voltages below 100 kV. At higher transmission voltages, overvoltages caused by switching may become significant because arrestor operating voltages limits are relatively close to normal system voltage and lines are usually long so that energy stored on the lines may be large. In most cases, without sustained traveling wave transients, surge arrestors have sufficient energy absorbing capability to damp harmful overvoltages to safe levels without permanent damage. Also, circuit breaker closing resistors will provide enough damping of switching surges for closing long lines.

B. Generation

1. Unit Stability

As system restoration progresses and more generating units return to service, the more stable the system becomes. More units mean stronger sources in terms of synchronized inertia and control of frequency and voltage. Stronger sources will afford more circuit energizations, unit start-ups, spinning reserve, and load pickups. However, caution needs to be observed during this period. There should be sufficient time between switching operations to allow the generating units to stabilize from sudden increases in load.

Automatic governor controls on generators should be placed in the automatic position to ensure instantaneous governor response to changes in frequency. Generating units should be loaded as soon as possible to a load level above their minimum loading point to achieve reliable and stable unit operation.

2. Load/Frequency Control in Area Islands

Generation and load should be adjusted in small increments to minimize the impact on the frequency. Loads should be added in block sizes that do not exceed 5% of the total synchronized generating capability. Frequency should be maintained between 59.75 Hz and 61.00 Hz with an attempt made to regulate toward 60.00 Hz. Manual load shedding may need to be used to keep the frequency above 59.50 Hz. As a guide, shed approximately six to ten percent of the load to restore the frequency 1 Hz. Large segments of load should only be restored if the frequency can be maintained above 59.90 Hz, and it is certain that such action will not jeopardize the transmission system of other paralleled areas. It may be helpful to increase the frequency to slightly above 60.00 Hz before each load block addition in the early restoration stages.

Even with the advantages of load with underfrequency relays enabled, it is advisable to resist picking up this type of load unless normal load pickup has been demonstrated to not cause frequency decay below the applicable underfrequency trip level. When load with underfrequency relays enabled is being picked up, it may be advisable to restore the load by alternating load pickup at each of the various underfrequency steps.

When interconnecting with another system, the frequency should be matched and maintained above 59.75 Hz and below 61.00 Hz. Anytime two or more isolated systems are operating in parallel, only one system should control frequency with the other system(s), controlling tie schedules unless load frequency control (LFC) is available. The best regulating units on the system should be used to regulate area or island frequency. The best units should be determined based on both the amount and quality of regulation provided. If the frequency regulation burden becomes too large for one unit, the frequency regulation should be shared by two or more units, preferably in the same plant control room for better coordination. If more than one area controls frequency, there would be a hunting effect without LFC. As a general guide, the regulation requirement to maintain frequency during system restoration should be about twice the normal requirement for the area load being carried at that time. Units not assigned to regulate frequency should be constantly redispatched to keep each regulating unit's energy at the middle of its regulating range.

3. Spinning Reserve

During system restoration, each control area should carry enough operating reserve to cover its largest generator contingency in each isolated area. This reserve can either be on-line generation that can produce additional power within ten minutes or customer load that can be shed manually within ten minutes. Operating reserve is required to enable the control area to restore its area (or subsystems) to a pre-contingency state (both tie lines and frequency) within ten minutes of a contingency. The smaller the area, the more of this reserve should be spinning. Connecting two or more systems together may result in a lower combined operating reserve requirement. However, caution needs to be used to ensure that load is not added too fast and the system collapses again.

C. Load Pickup

1. Cold Load Pickup

Restoring customer load to service, which has been disconnected for some time, presents new challenges. The disconnected load will probably be much higher than its value at the time of interruption. The simultaneous starting of motors, compressors, etc., will cause high peak demands for power. These higher than usual load requirements are commonly referred to as cold load pickup. Cold load pickup can involve inrush currents of ten or more times the normal load current depending on the nature of the load being picked up. This will generally decay to about two times normal load current in two to four seconds and remain at a level of 150% to 200% of pre-shutdown levels for as long as 30 minutes. When restoring load, sufficient time must be allowed between switching operations to permit stabilizing the generation.

2. Priority Customers

Each control area should develop a priority restoration scheme for its customer load. These load restoration schemes need to address the control area's requirements as well as those of the community. Providing station service to nuclear power plants and providing service to facilities necessary to restore the electric utility system should be the highest priority.

As conditions permit, the system operator should consider providing service to critical loads such as generating plant fuel supply depots, military facilities, law enforcement organizations, facilities affecting public health, and public communication facilities.

3. Automatic load Restoration Schemes

The system operators need to control and remain in control of all aspects of the system restoration. Automatic devices, which protect the system (relays, voltage regulators, etc.) should be in service as quickly as possible. Other automatic devices such as automatic load restoration schemes should not be enabled until a sufficient portion of the system generation and load have been restored unless the possibility of automatic restoration is factored into the portion of the system being energized.

Section VII approved by Operating Committee July 16 – 17, 2003

VII. Reliability Coordinator Responsibilities During Restoration

A. *Early Restoration Stages*

1. Communications

The Reliability Coordinator's primary role in the early stages of power system restoration is to coordinate the exchange of information among the systems under the Reliability Coordinator's purview (the Reliability Coordinators' "members"), other Reliability Coordinators, NERC, and the Regions. The Reliability Coordinator should initially endeavor to establish lines of communication with its members via normal systems or, lacking those, through any available means. As soon as practical, the RC should establish communications with other Reliability Coordinators and NERC via the NERC hotline and Reliability Coordinator Information System or, lacking those, through any available means. Communications with the Regions should be on an as-needed basis. Information to be gathered from members and exchanged with other Reliability Coordinators and NERC would typically include:

- The extent of the required restoration effort in the Reliability Area (transmission and generation facilities not available for service).
- High-level summaries of the members' initial plans to begin restoration.
- The progress being made to restore generation capacity (for example, key generating facilities restored, milestones achieved associated with generation, etc.).
- The progress being made in restoring transmission facilities (for example, a list of bulk power substations re-energized, milestones achieved associated with transmission, etc.).

2. Information Sharing

Information from other Reliability Coordinators or NERC to be shared with members would typically include:

- Status of power system restoration progress in adjacent Reliability Coordinator areas.
- Information regarding the cause of the system collapse.

B. *Later Restoration Stages*

As the power system restoration process progresses, the responsibilities of the Reliability Coordinator increase. The Reliability Coordinator should:

- Work with the Control Area Operators to review the power system data to facilitate the RC's real-time data acquisition in order to determine the overall state of the power system.
- Work with the Control Area Operators in order to ensure that sub-regional switching is coordinated as the system is restored.
- Work with the Control Area Operators and neighboring Reliability Coordinators to determine when interconnections in adjacent Reliability Coordinator areas can take place.

Throughout the restoration process, the RC should assess its ability to perform the RC functions required by NERC Policy 9. As system conditions and data availability permit, the RC should verify that it has successfully restored its ability to perform each function.

C. Reliability Coordinator Training

Reliability Coordinators should have knowledge of the restoration plans and procedures within their defined area of responsibility. Restoration drills plus other training as needed should take place on an annual basis.

VIII. Training and Testing

The development of training and testing for electric system restoration requires careful consideration and is specific to each utility. From a global perspective, however, the utilities within a control area should share common objectives. In order to enable each utility to develop an effective training plan, this section will focus on presenting a training schematic. Employee input and involvement are the prime catalysts in all aspects of training.

A. Goals

The area utilities should first develop training goals by listing the objectives specific to each utility. The goals should encompass conditions, concerns, contingencies, post-outage generation resource forecast, automatic circuit breaker operations, training needs of personnel, and procedures specific to the area.

Typical area goals might be expressed as follows:

1. "Provide electric system restoration training for system operations personnel in order to build confidence, optimize effectiveness, and nurture teamwork."
2. Provide a basis for better communications concerning electric system restoration between utilities and groups within utilities.≅

B. Decision Making and Priority Setting

Training priorities should be set in order to make tough decisions regarding the depth and focus of training. The backgrounds and needs of utilities vary, so the training program of each also may vary from that of a neighboring system.

Training tasks should be identified which will help attain the goals. The training tasks identify the nature of training, but do not say how to do it. Priorities must be established for the training tasks. The tasks and priorities should be developed and scrutinized by employees closest to the daily operations.

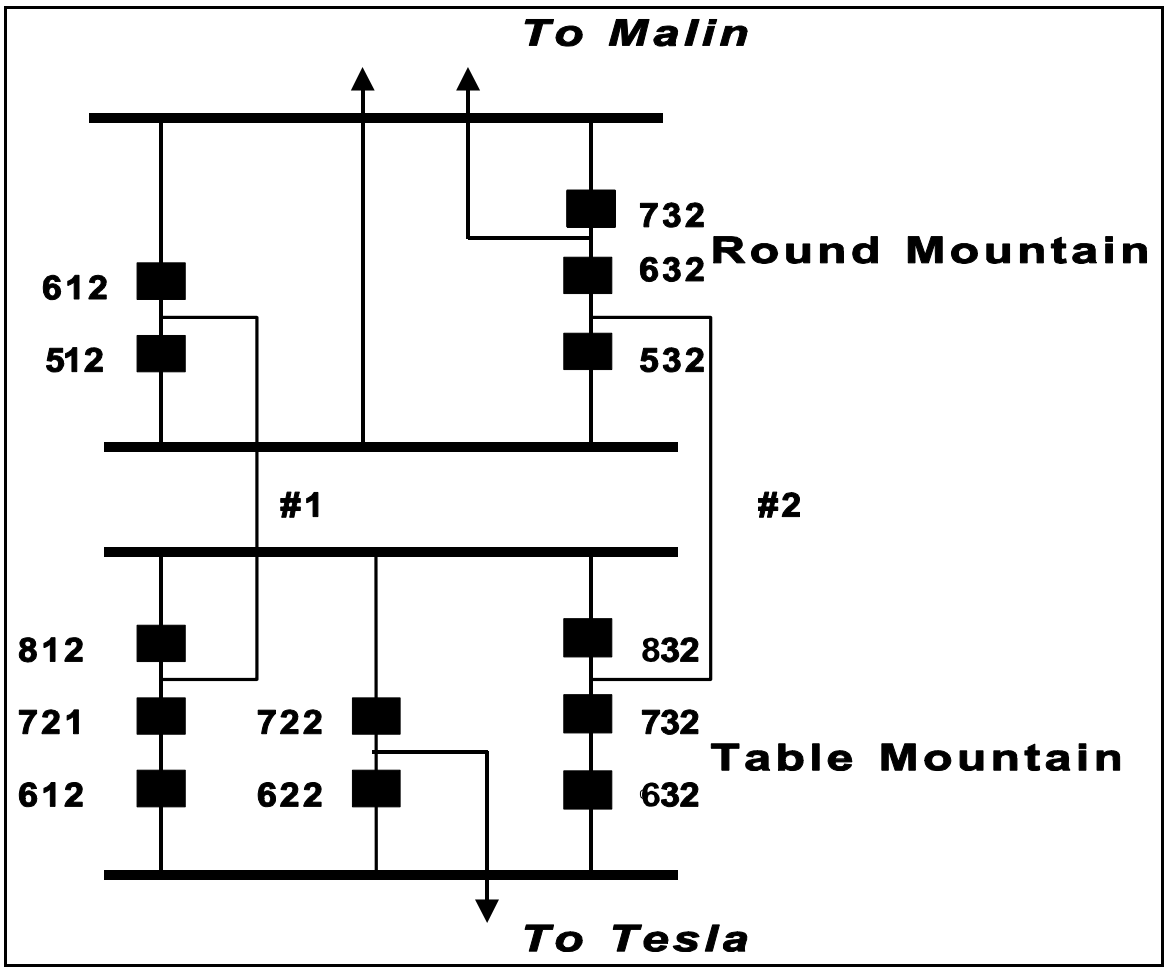
Typical restoration training priorities include the following:

1. Enhance understanding of anticipated post-collapse system conditions and alarms.
2. Review existing dispatching instructions and procedures.
3. Develop and be prepared to use a functional restoration diagram for tracking system restoration down to and including major 115 kV, such as the example shown in Figure 2.
4. Refine and update system restoration procedures using simulation if available.
5. Study and project response to restoration procedures regarding generation sources, interconnections, AGC control mode, frequencies, governor bandwidth, voltage rise, relaying parameters of potential impact, backup control center, and voltage change anticipated from reactive changes at substations with little or no power flow.
6. Promote increased awareness of problems arising from picking up load with isolated generation, including frequency deviation anticipated, potential distribution underfrequency relay action, potential generation overspeed trips in response to distribution load trips, frequency control methods, reactive control, maintaining unit stability, increasing frequency by 0.5 to 1.2 Hz before incremental load pickup, and control of electrical system load being restored.
7. Knowledge of problems associated with attempting to pick up portions of the system while avoiding restoration of uncontrolled loads by automatic controls or field personnel actions when necessary.

8. Familiarization with specific devices for use in controlling line voltages: EHV line shunt reactors, tertiary shunt reactors, unloaded banks, banks with controlled amounts of load, synchronous condensers, static var compensators, bypassing series capacitors, and the anticipated magnitude of the voltage change to be realized from each action.
9. Encourage teamwork within each control center and between control centers.
10. Promote coordinated response and understanding across corporate cultural lines of plants, divisions, regions, and business units or other organizational boundaries.

C. *Methodology*

Each utility should construct a plan for implementing restoration training, outlining how the training will be done. The methods developed should be focused upon providing the training tasks, which serve to accomplish training goals. In addition, the methods proposed should be subjected to a review to ensure the methods can be supported. Suggested prerequisites to consider for checking to ensure that training can be supported include practicality, human resources required to accomplish, support by involved parties, and budget allocation.



Some training methods might include the following:

1. Classroom review of critical technical information and reference to procedures, including automatic generation control (AGC) modes, frequency sources for AGC, coordination, power pool or coordinating council notification procedures, loading or stability

constraints, detailed procedures for specific plants or portions of the system, and equipment voltage limits.

2. Simulator demonstrations involving isolated system response.
3. Simulator demonstration of voltage changes by various voltage control methods.
4. Guest speakers for classroom PC slide show presentations on remedial action, special protection schemes, contingency studies, and protective relaying impact on restoration.
5. Simulator or classroom work group assignments to respond to total system blackout and take actions up to and including total system restoration. Suggested scenarios should include both with and without outside sources of generation or supply.
6. Simulator restoration or work group assignments may be combined into contiguous segments:
   a. System analysis
   b. Assignment of responsibilities
   c. Determination of plan(s) to implement linking resources with critical needs, such as nuclear plants and control centers
   d. Restoration and express routes for linking first resources with power plants
   e. Bulk load restoration
   f. Subsequent day's load reduction measures or rotating outage implementation if resources are insufficient at peak.

D. Testing Equipment and Procedures

In addition to training, possible simulation, and operations preparedness, the communication links and procedures within and between utilities should be Atested≅ by means of periodic use and, if possible, training drills or exercises.

E. Measuring Effectiveness

It is recommended that measurements be established to determine the effectiveness of restoration training. The measurements may be suited to individual needs, but may include:

1. Training results critique to be completed by the people being trained
2. Annual system restoration knowledge level questionnaire
3. On-the-job evaluation of restoration knowledge

Any demonstrated application in restoring smaller parts of the system also can be included. The desirability of measuring training effectiveness is now perceived by many as a preferred strategy rather than that of testing individuals. It is most difficult to test an individual's operating ability without simultaneously lessening the focus upon learning. Each utility must determine the best strategy in view of specific needs, goals, and resources.

All aspects of restoration are extremely important. However, the mere presence of procedures does not ensure optimum response. Training is an important element, which can bridge the gap between what we want to happen and what will really happen with respect to restoration. The NERC Operating Guides and associated appendices are excellent resources for training assessment and development.

NERC BACKUP CONTROL CENTER

A Reference Document

EPRI Project RP2473-68

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Appendixes

Appendix A — Bibliography
Appendix B — Utility Questionnaire

1. Introduction

This reference document is intended to aid control center managers in scoping, justifying, and planning a backup control center (BUCC). Since control centers differ in their functions and responsibilities, each utility must decide which functions are critical and need to be performed when operating from an alternate location. To aid a utility in justifying and designing its BUCC, key issues to be considered in planning a BUCC are provided. Common issues, such as control center threats and their resultant impacts, are discussed in general terms. Alternative BUCC solutions that are related to a utility's specific responsibilities within its control area are discussed using prototype situations to further guide a utility based on its own operating requirements.

The information contained in this reference document was obtained both from a search of current literature on backup control centers and from a survey of utility personnel with expertise in the planning and use of backup control centers. Appendix A contains a bibliography of current literature used as reference material. Appendix B contains a copy of the questionnaire used in the utility survey.

Individuals from the following utilities were contacted during the survey process and they provided the bulk of the information included in this document.

American Electric Power Corporation
Baltimore Gas & Electric
Bonneville Power Administration
Boston Edison Company
Delmarva Power & Light Company
Detroit Edison Company
Entergy Services, Inc.
Florida Power & Light Company
General Public Utilities
Michigan Electric Power Coordination Center
New England Power Exchange
New York Power Pool
Ontario Hydro
Orange & Rockland Utilities, Inc.
Pacific Gas & Electric Company
PJM Interconnection Association
Pennsylvania Power & Light Company
Public Service Electric & Gas Company
Southern California Edison Company
Tucson Electric Power Company
Union Electric Company

2. Criteria for Critical BUCC Functional Capabilities

NERC Guide III, G. Recommendation 5 states that the standards of Guide I should be considered when developing the plan to continue operation. The standards of Guide I address the functions of generation control, voltage control, time and frequency control, interchange scheduling, and inadvertent interchange management. In addition, utilities require either manual or automated control of critical substation devices; logging of significant power system events; and, as appropriate, hourly interchange accounting. These functions to the extent they are operating responsibilities of the primary control center provide the minimum set of recommended functional capabilities for a BUCC.

In addition, a BUCC may also be required to support other corporate or power pool responsibilities that are normally performed by the primary control center. For example, power pool accounting or corporate-wide access to historical data may be required.

3. Threat Assessment for the Primary Control Center

Most utilities that have already implemented BUCCs did not perform a quantitative threat assessment. These utilities considered the consequences of a control center loss and the resultant concern for power system security as sufficient justification for implementing a BUCC. This type of qualitative justification is most prevalent among utilities that are located in areas prone to natural disasters.

The objective of performing a threat assessment is to determine the range of control center outages that need to be considered when planning for a BUCC. Brief outages (less than two hours) are not normally considered in a threat assessment, since their incremental impact to operations is small. A quantitative methodology for threat assessment and for BUCC cost justification involves the following steps:

(a) Determine the likelihood of losing a control center
(b) Quantify the consequences for different disaster scenarios
(c) Prepare a risk analysis using probabilities and cost consequences

3.1 Control Center Threats

When performing a threat assessment, the following types of events that could disable a control center should be considered:

(a) Natural disasters, such as hurricanes, earthquakes, tornados, floods, and other weather caused conditions. The frequency and severity of these natural disasters can be forecasted by using historical data.
(b) Accidents, such as fire, internal environmental problems, flooding, chemical spills, plane crash, explosion, loss of communications, and other catastrophic events. The frequency of accidental events may be obtained from insurance carriers or other industry experts.
(c) Sabotage, such as bomb threats, software viruses, and other malicious actions. The frequency of these events can be grossly estimated from the use of historical data and from information from other studies.

The overall annual frequency of control center loss is the total of the individual frequency for each of the above three classifications. Based on a utility's location, the frequency of occurrence for each of these classifications could differ by a few orders of magnitude.

3.2 Impact on Control Center Operation

The above threats can result in various impacts to control center operation. The severity of these impacts can range from a forced evacuation of a few minutes up to the complete rebuilding of the control center facility. A comprehensive plan for justifying a BUCC should consider a full range of potential disaster durations, the following ranges of outage durations are appropriate:

(a) Short term — up to 48 hours
(b) Intermediate term — up to two weeks
(c) Long term — over two weeks

Please note, the number of classifications and the outage durations for the classifications can be tailored to the actual circumstances of a particular utility.

The following types of impacts to control center operations should be considered during the threat assessment process:

(a) Impacts that normally result in short-term outages:
  (1) required evacuation of the control center
  (2) loss of communications
  (3) loss of EMS/SCADA system
  (4) loss of critical data
  (5) loss of control center support facilities, such as air conditioning, power, and water
(b) Impacts that may result in intermediate-term outages:
  (1) damage to private microwave system
  (2) severe damage to EMS/SCADA system
  (3) damage to the control center facility
(c) Widespread damage to the control center facility could result in a long-term outage lasting many months

The cost consequences of these outages both with and without a BUCC can then be used in justifying the need for a BUCC.

3.3 Worst-Case Scenario

The cost consequences of a control center outage depend upon the state of the power system at the time the disaster occurs. A worst-case scenario would be a disaster that not only caused the loss of the control center facility, but also caused widespread outages in the electrical network. This would result in not only increasing the recovery time for the power system disturbance, but would most likely result in extended hours and deteriorating working conditions for both operating staff and field crews. This could lead to accidents, inaccurate records, and potentially unstable operating conditions. Because the costs associated with this type of worst case scenario would be almost impossible to determine, this document considers only the loss of the control center under normal power system conditions.

4. Justification for a Backup Control Center

As stated before, a utility can take one of two approaches for justifying a BUCC: a qualitative justification that discusses the costs of a control center loss and benefits of a BUCC in general terms, and a quantitative risk analysis that develops a complete cost justification for a BUCC. While gathering information for this document, it became apparent that most utilities with a BUCC performed a qualitative analysis to justify a "bare bones" backup facility.

4.1 Qualitative Justification

A qualitative justification is usually based on an opportunistic occurrence where the incremental cost to add a BUCC is small, such as the procurement of an EMS or the installation of a SCADA system at a remote regional control center. Where the threat of natural disasters and/or sabotage are significantly greater, a more sophisticated BUCC facility is more readily justified because of management's concern for power system security or by other outside pressures.

Qualitative justifications should be based on NERC Guide III.G. criterion that control centers have plans and backup capability to avoid placing burdens on neighboring control areas. The cost of implementing these plans, including any cost to transfer control to an adjacent control area, purchase regulating service, or to operate the system in a conservative manner to assure system security, should be compared to the cost of implementing a BUCC.

4.2 Quantitative Risk Analysis

When performing a quantitative risk analysis, the following issues need to be considered:

(a) The change in average daily production cost with and without a BUCC
(b) Loss of revenue from potential interchange transactions
(c) Cost of additional staffing to support manual operations from critical locations for an extended period of time
(d) Effects on power system security based on potential loss of equipment due to lack of network security software
(e) Costs for training operators to work under emergency conditions from a backup facility for an extended period of time

The cost for each of the above items will be affected by the functional capabilities implemented in the BUCC. Different risk scenarios can then be used to evaluate the appropriate level of BUCC functionality. In disaster planning, the amount of resources worth investing in emergency facilities is evaluated using risk analysis. In this content:

$$\text{Risk} = \text{Consequences} \times \text{Frequency}$$

In justifying a BUCC, the consequence is the cost difference between operating with and without a BUCC. This cost difference must take into account the different yearly probabilities and estimated outage durations. The frequency is the expected frequency of loss of the primary control center as discussed in Section 3.1. Risk can then be quantified as an Expected Annual Cost (EAC). The expected useful life of the BUCC must be used with the EAC in calculating the present worth of the BUCC. The

dollar amount worth spending on a BUCC is equal to its present worth. Clearly, this is not a precise analysis method.

4.3 Scope of the BUCC

The cost justification of expensive disaster recovery facilities is made difficult by the extremely low historical frequency of control center disasters. The low probability of an individual utility experiencing a disaster tends to justify only low budgets for a BUCC. This has led utilities to use manned backup facilities with only radio and telephone communications to monitor and control the power system during a control center disaster or outage. This method provided an initial low cost solution; but, in the long term, it was expensive to develop and maintain an adequate set of manual operating procedures. An increasing risk associated with a BUCC that relies on manual operating procedures is the inability of system operators to manage the complexities of a power system over an extended period of time without automated tools. For this reason, a manual control-oriented BUCC should only be considered as an adequate backup for short-term outages (up to 48 hours), and should not be used for protection against disasters that render the primary control center unusable for several days or more.

5. Alternative Solutions for Backup Control Centers

This section discusses alternative BUCC solutions in terms of control center prototypes that are used to represent a range of utility operating responsibilities in a control area. These prototypes are then used to discuss the metering and communications requirements that are necessary to support the critical BUCC functions as described in Section 1. Later sections discuss alternative BUCC solutions based on these prototypes.

Prototype	Control Area Responsibilities	Control Center (CC) Configuration
1	Primary control center performs complete control area dispatch	Single primary control center
2	Primary control center performs complete control area dispatch	Primary control center with subordinate control centers
3	Primary control center performs AGC but does not directly control generating units	Primary control center with subordinate control centers
4	Control center does not perform AGC but sends control signals to generating units	Single control center
5	Control center does not perform AGC but sends control signals to generating units	Control center with subordinate controls centers
6	Control center has no involvement in AGC	May or may not have subordinate control centers

5.1 BUCC Metering and Communication Requirements

Regardless of the level of sophistication of the BUCC, the most important considerations when implementing a BUCC is the availability of both voice and data communication facilities. Providing adequate communicatatis is the major portion of the cost for a BUCC. It is essential for system operators at the BUCC to have voice communications with operating personnel that they normally communicate with from the primary control center. If the BUCC is to include data monitoring and supervisory control, the communications facilities must also include data channels to remote terminal units located at key substations. Data channels may also be required to send control signals to generating plants or subordinate control centers as appropriate. The following table provides the metering and communications requirements for each of the BUCC prototypes.

BUCC Metering & Communicataon Requirements	Prototypes					
	1	2	3	4	5	6
1. Instantaneous tie-line MW and Mvar telemetry	✓	✓	✓	–	–	–
2. Instantaneous generating unit MW telemetry	✓	✓	✓	✓	✓	–
3. MWh accumulator readings for all tie lines and generating units	✓	✓	✓	–	–	–
4. SCADA for generating units	✓	✓	–	✓	✓	–
5. SCADA for unmanned, critical substations	✓	✓	–	✓	✓	✓
6. System frequency and time error measurements	✓	✓	✓	–	–	–
7. Data links to send generation control signals to subordinate centers	–	–	✓	–	–	–
8. Voice communications to manned power plants	✓	✓	–	✓	✓	–
9. Voice communications to manned, critical substations	✓	✓	–	✓	✓	✓
10. Voice Communications to subordinate control centers	–	✓	✓	–	✓	✓
11. Voice communications to higher-level control center	–	–	–	✓	✓	✓
12. Voice communications to neighboring control centers	✓	✓	✓	✓	✓	✓

5.2 BUCC Alternative Solutions

The BUCC alternatives available to an electric utility range from a basic "war room" equipped with system maps, diagrams, telephones, radios, and manual procedure documents to a full-function replica of the primary control center complete with most, if not all, application software used for control of the power system. As the level of sophistication of the BUCC facility increases, so in general, does its initial implementation cost. However, the ongoing support cost of a BUCC is normally inversely proportional to its degree of sophistication due to the costs associated with developing, maintaining, and teaching the skills and procedures required to support the manual operation of the power system. The following sections list the configuration alternatives for implementing a BUCC at utilities with and without subordinate control centers.

5.2.1 Utilities Without Subordinate Control Centers (Prototypes 1, 4 and possibly 6)

These utilities are at a disadvantage in that there is no obvious location, such as a divisional control center, to assume the backup control functions if the primary control center is disabled. The solution is to select an existing facility, such as a previous control center site or an office facility, that has access to the communications facilities and thus can be provided with the data necessary to perform the required BUCC functions. The selected facility should be sufficiently removed from the primary control center in order to isolate it from the same threats that may render the primary control center inoperable.

The following types of alternative configurations can be deployed at the BUCC depending upon the level of functionality required:

(a) A remote facility with a complete backup EMS/SCADA system (either a single or dual processor). This configuration provides full functionality at the BUCC, but also requires a large amount of telemetry and data to support it. The use of a retired EMS or SCADA system to perform as the BUCC is a way to reduce the initial implementation cost; however, the long-term maintenance costs are usually high due to a lack of spare parts, inadequate documentation, and cumbersome software/database maintenance tools.

If the BUCC is an exact duplicate or a subset of the primary control center, then the BUCC could also be used as a remote maintenance site for troubleshooting hardware, as an additional source for critical spare parts, and as a remote test site for newly developed or modified software.

(b) A remote facility with reduced functionality using one or more workstations and/or personal computers. This configuration provides the most functional flexibility and ease of expansion. Advancements in networking and distributed systems/database technologies have allowed utilities to implement a basic set of SCADA/AGC functions on microprocessor-based platforms that can be easily expanded in the future via third-party software products that run under standard operating systems, such as UNIX and DOS. Custom operating procedures and software/database maintenance tools must be developed to support this type of BUCC configuration.

(c) A remote facility with minimum requirements that is used for manual dispatch. A utility must determine if adequate system regulation can be maintained using manual

generation control. As mentioned above, manual operation from a BUCC should only be considered as a backup strategy for short-term emergencies. Specific plans and procedures should be in place for establishing an adequate backup facility if a longer-term outage occurs at the primary control center. This may be accomplished either by an agreement with a neighboring utility to provide backup control area capability or by acquiring backup equipment and communications at the BUCC under emergency conditions. If a neighboring utility is to provide adequate system regulation, then tie line MW telemetry must be made available to it.

5.2.2 Utilities with Subordinate Control Centers (Prototypes 2, 3, 5 & possibly 6)

These utilities may use any of the BUCC configurations described in the previous section and also have access to the facilities of the subordinate control centers. Once again, the communications system is key to the functionality of the BUCC. If one or more of the subordinate control centers has access to all of the data available to the primary control center, it is possible to duplicate the functionality of the primary control center by locating the BUCC at the subordinate control center. Otherwise, the functionality of the BUCC will be limited to the data available at the subordinate control center site.

In addition to the configurations described in Section 5.2.1, the BUCC control system at a subordinate control center may also take the following forms:

(a) A stand-alone system (either single or dual processor) that utilizes the subordinate control center's communication facilities. This configuration minimizes the impact of any BUCC activities on the existing computer system.

(b) Use of the redundant portion of the existing subordinate control center computer system to perform the BUCC functions. In this configuration, special backup software that is normally deactivated can be initialized on the redundant processor of the existing system whenever there is a need for the BUCC. If there is an extended outage of the primary control center, this configuration can provide an interim solution that will allow sufficient time to procure additional hardware to implement the BUCC functions on a separate system and, if necessary, expand the overall functionality of the BUCC.

5.2.3 Other Alternatives

Many utilities, regardless of their prototype categories, include a development system or a stand-alone operator training simulator in their EMS/SCADA system configuration. Each of these systems can be a potential BUCC if located at a remote site. The only resources they lack are sufficient communication interfaces to remote facilities for performing the required monitoring and control actions. For an incremental investment either of these systems can be expanded to include the necessary communications interface equipment.

Another alternative is the use of a high performance workstation that is normally used as a remote console. Under emergency conditions, the workstation can be reconfigured and enhanced with SCADA and AGC capabilities to perform a minimum set of BUCC functions, assuming sufficient data and voice communication access to critical remote facilities is available.

6. Training and Maintenance Costs

In addition to any leased communication costs, there are two main elements to the recurring cost of a backup control center; training and maintenance.

6.1 Training Costs

Training will consist of classroom training in the procedures to evacuate the primary control center, activate and occupy the BUCC, operate from the BUCC, and validate and reactivate the primary control center once the emergency condition has cleared. The amount of required training will increase in proportion to the degree the tools and procedures used in the BUCC are different than those used in the primary control center.

In general, if time is already allocated for an ongoing operator training program, the BUCC training should have a relatively small incremental cost associated with it. Otherwise, it will be necessary to bring operators in for training at special times and may involve overtime costs, as well as the cost for developing the training materials.

In addition to classroom training, there is the need for periodic drills to practice transfer procedures from the primary to the backup control center. Since most utilities staff both the primary and backup control centers during drills, the cost will be the overtime costs for a second shift of operators. These drills are normally conducted at a periodicity that ranges from quarterly to yearly. The duration of the drills normally range from an hour to a maximum of 24 hours.

6.2 Maintenance Costs

Three aspects of BUCC maintenance are hardware, software, and database/display updates. The degree of difficulty of all three areas is related to the configuration of the BUCC compared with that of the primary control center.

Even if the BUCC is based on entirely manual operations, (i.e., does not have any computers or other control equipment), there will still be some maintenance cost. This cost will be to maintain adequate communication circuits, written evacuation and startup procedures, log sheets, system diagrams, substation diagrams, relaying diagrams, operating procedures, and other textual material normally stored in a computer system.

If the BUCC is an exact duplicate or a subset of the primary control center, the incremental maintenance costs associated with the BUCC should be relatively small. Depending on whether the utility performs self-maintenance or contracts out hardware maintenance, the incremental hardware maintenance cost will either be negligible or a function of the additional hardware to be maintained. The software, database, and display maintenance can be accomplished as part of the primary control center maintenance and simply involves transporting the changes to the BUCC site and loading them into the BUCC. This can also be accomplished via a data link if the two centers are interconnected.

If the BUCC is the functional equivalent of the primary control center, but uses different hardware and software, such as the system previously used at the primary control center, all three elements of the maintenance costs will escalate and may approach those of the primary control center. The hardware maintenance will require unique training, test equipment, and spare parts. All software

changes and database and display edits performed at the primary control center will have to be repeated at the BUCC.

In addition to the above cases, there are various configuration alternatives that impact the maintenance costs. For example, the use of a BUCC with reduced functionality that is configured with PCs and workstations rather than minicomputers will reduce both hardware and overall system maintenance costs. Maintenance also depends on whether the BUCC has any other functions when the primary control center is operational. If the BUCC is normally used for other purposes, the incremental maintenance cost for its use as a BUCC will be very small. Similarly, if the BUCC is co-located with an existing control system that requires an on-site maintenance staff, the cost of BUCC maintenance will be reduced significantly.

In addition to the BUCC maintenance costs, a utility should also consider an annual budget for software upgrades both to enhance economic operation and overall power system security and to maintain a level of "open system" standards that are compatible with those implemented on the primary control system. This level of compatibility will allow both systems to evolve together as the responsibilities and interface requirements for the control center change over time.

7. Conclusion

The following conclusions regarding the planning of a backup facility were drawn from the survey of utilities with existing BUCCs:

(1) The most critical issue, based on both initial and recurring costs, in implementing a backup control center is its access to both voice and data communication facilities. It is for this reason that the majority of backup control centers are currently located at regional control centers or other utility locations that have access to a company-wide communications network. Installing the BUCC at a regional control center also has the advantage of an on-site maintenance staff and already existing support facilities for an on-line control system. For those utilities without regional control centers, a remote facility that houses an operator training simulator, a software development system, or a high-performance workstation may be a good candidate for a BUCC if sufficient communication facilities are available.

(2) Most backup control systems are implemented as an opportunistic addition to a larger procurement, such as a replacement EMS or a regional SCADA system. However, utilities that do not have a BUCC can use advances in communications networking and control system platforms to reduce its cost for implementing a BUCC. Microprocessor-based technologies, the industry-wide migration to de facto software standards (e.g., UNIX, TCP/IP, SQL) and high-level languages, and the ability to network diverse computer systems have driven down both the hardware and software costs for implementing a backup control system while improving the available processing power for a reduced function backup facility.

(3) The scope of the BUCC should not only satisfy the minimum requirements as described in Section 2, but should also have sufficient functionality to cover most long-term disasters. On average, backup control systems have been designed to support emergency operations for up to a six-month period. For severe control center outages that extend beyond the six-month period, the six months will allow sufficient time to enhance the backup control system into a redundant, fully functional primary control system.

Appendix A

Bibliography

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Appendix B

Utility Questionnaire

Introduction

This survey is being conducted by Macro Corporation under the sponsorship of the NERC Operating Reliability Subcommittee and EPRI within the framework of EPRI Project RP2473-68. The survey responses will be used in the study collectively and no reference will be made to the name of the organization nor the source of specific information. However, a list of the organizations responding to the questionnaire will be included in the study report. If you do not wish the name of your organization to appear in the list, please check the box below.

☐ Do not use the organization name in the report.

Objectives

The objective of the study is to prepare a reference document for utility use in scoping, justifying, and planning a backup control center.

The objective of this survey is to obtain sufficient information about current knowledge of and experience with backup control center planning and implementation. This information will be used to define general control center prototypes based on operational responsibility and specific planning elements to be incorporated into the reference document.

Method Of Response

After you have had time to review the survey you will be contacted by Macro to arrange a telephone interview during which we will receive your responses verbally. If you prefer, you may respond in writing and we will call you only if we require further clarification of your answer.

1. Organization Data

1.1 Organization Name

1.2 Discuss Your Operating Responsibilities

a. Involved in generation control
b. Calculates ACE
c. Receives generation control signals from higher level control center
d. Sends signals to units
e. Sends signals to lower level control center

1.3 Control Center Location

2. Control System Data

2.1 SCADA or EMS
2.2 Manufacturer and Installation Date
2.3 Functions
Consider the following:
a. SCADA — RTUs (#)
— Data Links (#)
b. Automatic Dispatching System (AGC, ED, ITS, RM, and PC)
c. Generation Scheduling (LF, UC, and ITE)
d. Power System Analysis (SE, BLDF, SSSA, PF, VS, SCD, and SENH)
e. Information Storage and Retrieval (PDSR, Energy ACC, and DDC)
f. Other-Specify

2.4 User Interface

a. Consoles — Local
— Remote
b. Mapboard
c. Trend Recorders
d. Other — Specify

3. Backup Control Center

3.1 Do you have a plan to continue operation in the event the control center becomes inoperable?
YES — Go to 3.4 NO — Continue

3.2 Explain the lack of a plan. Was it a conscious decision or default? Is there a plan to reconsider?

3.3 If it was a conscious decision, explain the basis for the decision.

3.4 Do you have a Backup Control Center (BUCC)?
YES — Go to 3.7 NO — Continue

3.5 Have you ever considered implementing a BUCC? Please explain why you have not considered one or why you decided against one.

3.6 Have you ever been in a situation where you would have used a BUCC if you had one? Please elaborate.

3.7 Did you perform a requirements or justification study before implementing the BUCC? If yes, please summarize the study and its results.

3.8 Discuss the types of emergencies that would force you to use a BUCC. What are the minimum and maximum durations you would expect to occupy the BUCC due to any single emergency or disaster? Discuss the range of backup plans you may have based on the severity of the incident.

3.9 What was the justification for the BUCC? Consider economic, political, emotional, results of a management audit, or other.

3.10 Were the costs and benefits quantified? If so, please discuss the methods used to quantify both.

3.11 What range of outage durations of the main control center was the BUCC designed to support? Consider:

a. Short Term — Up to 48 hours
b. Intermediate Term — Up to two weeks
c. Long Term — Over two weeks

What plans do you have if the outage exceeds the planned duration?

3.12 Where is the BUCC located with respect to the main control center? Are the BUCC site and facilities used for any other purpose when the BUCC is not in use? If yes, please elaborate.

3.13 What facilities are provided at the BUCC? Consider the following:

a. Computers — Host Minicomputers, workstation(s), PC(s), calculators, and analog equipment
b. Consoles — Local and/or remote
c. Mapboard, trend recorders, etc.
d. Local meters
e. Maps, one-line diagrams, log sheets, operating instructions, system documentation, and the like

3.14 What communications are available at the BUCC? Consider the following:

a. Data from RTUs? Data links? Other?
b. Dedicated voice channels to power plants, other control centers, other company facilities, and other places.
c. Dial-up voice channels
d. Radio channels

3.15 What functions are available at the BUCC? For each function performed at the main control center, estimate the percent that is available at the BUCC? (For example x% of the RTU data available at the main control center is available at the BUCC.)

3.16 For those functions not available at the BUCC, how are they performed when the main control center is down? For example, the transmission coordination and monitoring functions that are normally performed at the main control center are parceled out to the divisional control centers when the main control center is down.

3.17 Discuss the method used to procure the BUCC. Was it implemented as a standalone project or as part of another project? Provide an estimate of the cost of the BUCC including procurement cost, project staffing, communications, training, facilities, and all other related costs.

3.18 Do you have written procedures for the following events?

a. Evacuation of the main control center
b. Occupation and activation of the BUCC
c. Functional verification and reactivation of the main control center

3.19 Do you perform system drills periodically where the BUCC is activated and used to control the electric power system? What is the frequency and duration of these drills?

3.20 Have you ever activated and used the BUCC because of a real problem at the main control center? If yes, please elaborate.

3.21 Discuss the impact of the BUCC on the following:

a. Staffing
b. Training
c. Documentation
d. Hardware Maintenance
e. Database and Software upgrades
f. Operation and Maintenance Budget

3.22 Discuss future plans for a BUCC or upgrading the existing BUCC.

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Time Monitoring Reference Document

Introduction

This procedure outlines responsibilities of reliability coordinators serving as time monitors in the North American interconnections. Changes to this reference document will be at the direction of the NERC Operating Committee (OC) with the participation of the NERC Resources Subcommittee (RS) and the Operating Reliability Subcommittee (ORS).

This document applies to current and future frequency or time related procedural responsibilities assigned to the time monitor in NERC standards or NAESB business practices.

Designation of Time Monitor

There will be one time monitor within each interconnection. NERC ORS will nominate a time monitor for each interconnection. The ORS will present the nomination to the NERC OC for acceptance. The NERC OC will forward the nomination to the NERC Board of Trustees for approval.

The term of each time monitor shall be one (1) year. With the exception of the Eastern Interconnection, the time monitor term shall be automatically renewed unless requested otherwise by providing a minimum of six (6) months notice to the NERC ORS. The Eastern Interconnection Time Monitor will rotate on an annual basis as outlined below. Should an existing or future time monitor no longer be willing or able to fulfill its responsibilities, the NERC Operating Committee will direct the NERC ORS to nominate a replacement and communicate the transition plan.

If a time monitor fails to fulfill its responsibilities, the NERC ORS will work with the time monitor to resolve the problem. The NERC ORS will submit a report to the NERC OC either identifying corrective measures taken or provide a recommendation for a new time monitor.

The NERC RS will report to the NERC OC and ORS any frequency or time error issues that may have been caused or aggravated by the time monitor or time error correction (TEC) practices.

Responsibilities of the Time Monitor

The time monitor will start and stop time error corrections as outlined in NERC standards and NAESB business practices.

The time monitor will terminate any TEC believed to be negatively impacting reliability. Requests for termination may come from any transmission operator or balancing authority operator to its respective reliability coordinator, who will notify the respective Interconnection's time monitor.

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The time monitor will provide accumulated time error following each TEC or at least monthly to the balancing authorities within its interconnection.

References

Links to each time monitor's local procedures to meet this procedure will be posted at the NERC RS Web site (http://www.nerc.com/filez/rs.html).

Interconnection Time Monitors

Each interconnection has identified the following reliability coordinator as its time monitor:

1. ERCOT Interconnection – ERCOT reliability coordinator
2. Québec Interconnection – Hydro-Québec TransÉnergie reliability coordinator
3. Eastern Interconnection – The reliability coordinators in the Eastern Interconnection will rotate the time monitor responsibilities on an annual basis as follows:
    a. IESO (Ontario) – February 1, 2011 through January 31, 2012
    b. NBSO (New Brunswick System Operator) – February 1, 2012 through January 31, 2013
    c. VACAR-South – February 1, 2013 through January 31, 2014
    d. SPP – February 1, 2014 through January 31, 2015
    e. NYISO – February 1, 2015 through January 31, 2016
    f. PJM – February 1, 2016 through January 31, 2017
    g. FRCC – February 1, 2017 through January 31, 2018
    h. ICTE – February 1, 2018 through January 31, 2019
    i. ISO-NE – February 1, 2019 through January 31, 2020
    j. SaskPower – February 1, 2020 through January 31, 2021
    k. Southeastern – February 1, 2021 through January 31, 2022
    l. TVA – February 1, 2022 through January 31, 2023
    m. Midwest ISO – February 1, 2023 through January 31, 2024
4. WECC Interconnection – WECC reliability coordinator