NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Coordinate Interchange Standard Drafting Team Meeting

Wednesday, September 8, 2004 — 8 am–5 pm
Thursday, September 9, 2004 — 8 am–noon

Hyatt Regency O'Hare
9300 W. Bryn Mawr Ave
Chicago, Il 60018
Phone: 847-696-1234

Agenda

1. **Administrative** **10 minutes**
   a. Welcome and Introductions — Chairman
   b. Arrangements — Secretary
   c. Antitrust Guidelines — Chairman **(Attachment 1)**
   d. Approval of Agenda — Chairman

2. **Relationship of Version 0 Draft 2 to CI Version 1 — Mike Oatts** **20 minutes**
   a. Implications of Version 0 Draft 2 on CI Version 1
   b. Moving forward with CI Version 1 (**Attachment 2**)

3. **Interchange Authority Function Task Force — John Simonelli** **1 hour**
   a. Update on Interchange Authority Function white paper
   b. Version 1.4, Draft 2 — Interchange Authority Function white paper **(Attachment 3)**

4. **Version 0 Standards — Roman Carter** **2 hours**
   a. Update on Version 0 Drafting Team actions (**Attachment 4**)
      i) RC and RA in Version 0 **(Attachment 5)**
      ii) Resolution of NAESB/NERC Buckets (**Attachment 6**)
         (1) Policy 3 Appendixes
         (2) Overview of NAESB Posting of CI Version 0 Draft 2 **(Attachment 7)**
   b. Discuss Templates 010–013 related to Interchange (**Attachments 8a** and **8b)**
   c. Review responses to posting of Version 0 Draft 1 Standards
      i) Interchange Subcommittee draft responses (**Attachment 9**)
         (1) Note comments on compliance requirements
      ii) Version 0 DT responses **(Attachment 10)**

5. Next Version of the CI Standard — Mike Oatts — Remainder of Meeting

a. Complete responses to first posting of CI Version 1 **(Attachment 11)**
b. Revise CI Standard Reference Document **(Attachment 12)**
c. Prepare CI Standard for second public posting **(Attachment 13)**
    i) Revise compliance requirements — Joe Willson
    ii) Finalize timing requirements — Peter Harris

6. Future Meetings — Secretary — 10 minutes

a. Calendar for 2004

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NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

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It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

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- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees
June 14, 2002

III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Organization Standards Process Manual
- Transitional Process for Revising Existing NERC Operating Policies and Planning Standards
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

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- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

NERC Home

Reliability Standards Home

Standards Authorization Committee (SAC)

Joint Interface Committee (JIC)

Registered Ballot Body

Contact Us

August 2004

Industry Comments on Draft 1 of "Version 0" Standards

Approximately 100 entities submitted written comments in response to the posting of Draft 1 of the "Version 0" Reliability Standards that ended on August 9. The Version 0 Drafting Team will be carefully considering those comments as they prepare a second draft of the Version 0 reliability standards for posting by September 3.

During September and October, several regional workshops will be held to hear comments and answer questions about the Version 0 reliability standards and the registration of reliability functions. NERC will work closely with the reliability regions and industry associations to schedule these workshops to optimize the opportunity for industry participation. Look for the workshop announcements soon.

The Version 0 standards will be considered for approval by the NERC standing committees in November and go to the ballot pool for vote in December 2004. The plan is to vote the entire set of Version 0 reliability standards as a block. Interested parties who have not enrolled in the ballot pool for the Version 0 standards should do so by going to the Ballot Pools page on the NERC web site.

Once the NERC Board of Trustees adopts the Version 0 reliability standards on February 8, 2005, the standards would immediately go into effect and all existing NERC operating policies, planning standards and compliance templates would be retired.

Adopting the Version 0 reliability standards is an important step toward completing the recommendations of the U.S.-Canada Power System Outage Task Force and NERC's own recommendations stemming from the August 14, 2003, blackout. An immediate benefit of the Version 0 reliability standards will be increased clarity in accountability for following NERC standards, achieved by adopting the functional model and by stating all requirements in active voice. The Version 0 standards will also provide a foundation for continued development of NERC standards using NERC's open, ANSI-accredited process.

NERC and NAESB Agree on the Scope of Version 0

Business Practices

One of the tasks of the Version 0 standards project was to identify potential business practices in the existing NERC operating policies and planning standards that could be assigned for development as NAESB business practice standards. The NERC Version 0 drafting team identified three areas of potential business practices: time error correction procedure, inadvertent payback procedure, and interchange scheduling. The NAESB Business Practices Subcommittee identified several additional areas of potential business practices, including: special cases of the ACE equation and the TLR procedure.

At its July 16 meeting, the Joint Interface Committee assigned development of Version 0 reliability standards to NERC and requested NERC and NAESB to form a task group of committee leaders to work out agreement on the scope of business practices in Version 0. That task group met on August 2-3 and reached a tentative agreement, subject to review of industry comments submitted to NERC and NAESB. The group is meeting again on August 13 to review the industry comments and make a final recommendation. The JIC will meet on August 16 in Houston to consider the final recommendation on Version 0 business practice standards.

The JIC was formed through a memorandum of understanding among NERC, NAESB, and the ISO/RTO Council. Its representation is divided equally among the three parties to the MOU. The group meets periodically to review standards requests and assign development of standards to NERC or NAESB.

NERC Board Approves Extension of Urgent Action Cyber Security Standard (1200)

In a ballot completed on July 14, the ballot pool approved renewing the Urgent Action Cyber Security Standard (1200) for one year by a weighted average of 96.4%. The renewal was adopted by the NERC Board effective August 13, 2004 to be in effect for one year. The drafting team for a permanent Cyber Security Standard (1300) is nearing completion of its first draft of the standard for posting.

Vegetation Management Standard Drafting Team Formed

The Standards Authorization Committee considered an extraordinary group of nominees to work on a vegetation management standard and assigned a drafting team to begin working immediately on the standard. Development of this standard is in response to a recommendation of the U.S. Canada Power System Outage Task Force and the NERC Board.

Reliability Standards Under Development

The status of other SARs and proposed standards are summarized below.

Gerry Cauley , Director – Standards

Reliability Standards Under Development

000	**Version O Reliability Standards** **Purpose:** There are several important reasons for accelerating the transition from existing operating policies and planning standards to a single set of reliability standards under the ANSI-accredited process: 1. The August 14 blackout has challenged NERC and the industry to demonstrate that its reliability standards are unambiguous and measurable – now. 2. The U.S./Canada Power System Outage Task Force final report of April 5, 2004 states in Recommendation 25: "NERC should reevaluate its existing reliability standards development process and accelerate the adoption of enforceable standards." 3. An April 14, 2004 order of the Federal Energy Regulatory Commission (FERC) states a policy objective addressing "the need to expeditiously modify [NERC] reliability standards in order to make these standards clear and enforceable." 4. The continued use of multiple formats, processes and forums for developing and maintaining reliability rules is an inefficient dilution of industry and staff resources. 5. The transition to new standards and retiring of existing operating policies and planning standards will be too complex for industry implementation if taken one standard at a time over several years. **Status:** The comment period for the first draft of Version 0 Reliability Standards closed on August 9. The drafting team is considering comments and plans to post a second draft by September 3.
100	**Coordinate Operations**

	Purpose: To ensure that the operations of each reliability authority (RA) function are coordinated such that they will not have an adverse impact on the reliability of other RAs and to preserve the reliability benefits of interconnected operations. **Status:** The drafting team reviewed the comments from the second posting of the draft standard.
200	**Operate Within Interconnection Reliability Operating Limits** **Purpose:** The purpose of this standard is to prevent instability, uncontrolled separation or cascading outages that adversely impact the reliability of the bulk transmission system. **Status:** The IROL drafting team identified a potential conflict with the Determine Facility Ratings Standard – and is exploring options available to move the standard forward. Either the definition of an IROL must be revised, or the requirements for establishing System Operating Limits (contained in Requirement 603 of the Determine Facility Ratings Standard) must be modified. The drafting team is working with the Determine Facility Ratings Team and the Operating Limits Definition Task Force to resolve this issue.
300	**Balance Resources and Demand** **Purpose:** To maintain Interconnection scheduled frequency within a predefined frequency profile under all conditions (i.e., normal and abnormal), to prevent unwarranted load shedding and to prevent frequency related cascading collapse of the interconnected grid. **Status:** Comments from the second posting of the draft standard are under review. Testing of several proposed measures is in progress.
400	**Coordinate Interchange** **Purpose:** To ensure that the implementation of transactions between sink and source balancing authorities are coordinated by the interchange authority such that the following reliability objectives are met: ▪ Each interchange schedule is checked for reliability before it is implemented. ▪ The balancing authorities implement the Interchange Schedule exactly as agreed upon in

		the interchange confirmation process. ■ Interchange schedule information is available for reliability assessments. **Status:** Comments from the first posting of the draft standard are under review.
	500	**Assess Transmission Future Needs and Develop Transmission Plans** **Purpose:** To establish a standard for assessing and planning transmission systems in North America. The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers. **Status:** Comments from the second posting of the SAR are under review.
	600	**Determine Facility Ratings, Operating Limits, and Transfer Capabilities** **Purpose:** Determine facility ratings, system operating limits and transfer capabilities necessary to plan and operate the bulk electric system within predefined facility and operating limits such that cascading outages, uncontrolled system separation and voltage and transient instability are avoided. **Status:** The SAC asked the drafting team to clarify some ratings requirements identified by FERC as possible gaps in the list of NERC reliability standards. The gaps address minimum criteria and peer reviews of ratings of lines and equipment. The drafting team plans to re-post their standard for comment in October.
	700	**Define (Physical) Connection Requirements** **Purpose:** To establish a standard for the proper physical connection of generation substations, transmission facilities, and load substations to the transmission systems to maintain reliability. **Status:** SAR approved for development. Not started yet.
	800	**Design, Install and Coordinate Control and Protection Systems** **Purpose:** To establish a standard for designing,

	coordinating and installing and maintaining automatic control and protection systems to provide for system performance within pre-defined limits. (For the purpose of this standard, automatic control devices include such facilities as Power System Stabilizers, Static Var Compensators, HVDC Modulation, Out of Step Relaying, etc.) **Status:** SAR approved for development. Not started yet.
900	**Monitor and Analyze Disturbances, Events and Conditions** **Purpose:** To establish a standard for evaluation and reporting of disturbances, events and conditions on the bulk electric system to determine how the power system responded to the events. The analysis is needed to make adjustments and/or modifications to the power system, procedures or standards to reduce the likelihood of an impact of future similar disturbances. **Status:** SAR approved for development. Not started yet.
1000	**Prepare for and Respond to Abnormal or Emergency Conditions** **Purpose:** To establish a consistent, uniformly applied standard for the development, coordination, implementation and maintenance of emergency plans. To require that an executable plan be in place to provide guidance for appropriate operation following conditions that have disrupted normal system operation. **Status:** SAR approved for development. Not started yet.
1100	**Prepare for and Respond to Blackout or Island Conditions** **Purpose:** To establish a consistent, uniformly applied standard for the development, coordination, implementation and maintenance of restoration plans. To require that an executable plan be in place to provide guidance for restoration of normal system operation following a blackout or island condition. **Status:** SAR approved for development. Not started yet.

1200	**Cyber Security (Urgent Action)** **Purpose:** To reduce risks to the reliability of the bulk electric systems from any compromise of critical cyber assets. **Status:** NERC Board of Trustees approved one-year extension, effective August 13, 2004.
1300	**Cyber Security (Permanent)** **Purpose:** To reduce risks to the reliability of the bulk electric systems from any compromise of critical cyber assets (computers, software and communication networks) that support those systems. **Note:** This standard is intended as a permanent replacement of the urgent action standard addressing the same issue. **Status:** The drafting team is working on the first draft of the standard.
1400	**Certification of the Balancing Authority Function** **Purpose:** To ensure that each entity that wants to be recognized as a balancing authority has the capability of performing the responsibilities assigned to the balancing authority function. **Status:** Comments from the first posting of the draft standard have been reviewed and the drafting team is preparing to post a second draft.
1500	**Certification of the Interchange Authority Function** **Purpose:** To ensure that each entity that wants to be recognized as an interchange authority has the capability of performing the responsibilities assigned to the interchange authority function. **Status:** Standard drafting underway.
1600	**Certification of the Reliability Authority Function** **Purpose:** To ensure that each entity that wants to be recognized as a reliability authority has the capability of performing the responsibilities assigned to the reliability authority function.

	Status: Standard drafting underway.
1700	**Certification of the Transmission Operator Function** **Purpose:** To ensure that each entity that wants to be recognized as a transmission operator has the capability of performing the responsibilities assigned to the transmission operator function. **Status:** Standard drafting underway.
1900	**Transmission System Vegetation Management** **Purpose:** This standard shall apply to 100 kV or higher voltage transmission lines (and lower voltage transmission lines determined to be critical to reliability by the Regional Reliability Councils) over which NERC has oversight. This standard is intended to improve the reliability of the electric transmission systems by eliminating transmission outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining safe clearances between transmission lines and vegetation on and along transmission rights-of-way, and establishing a system for reporting vegetation-related outages of the transmission systems (+200 kV) to the respective Regional Reliability Councils and NERC. The August 14, 2003 blackout is the most recent demonstration that ineffective vegetation management may have serious adverse impacts on the reliability of the electric transmission systems. This standard will assist in reducing vegetation-related transmission outages by requiring each transmission owner to have a documented vegetation management program in place, including documentation of its implementation. Each program is to be designed for the geographical area and specific design configurations of the transmission owner's system. This standard will also provide for uniform reporting of vegetation-related outages to the Regions and to NERC so that Planning Authorities and Reliability Authorities may measure the impact of vegetation-related outages on the reliability of the interconnected electric transmission systems. **Status:** The standard drafting team has been formed.
☐	**Amend Standards Process Manual**

Purpose: The purpose of this SAR is to amend the NERC Reliability Standards Process Manual to remove the requirement that all modifications to the process manual be accomplished through the standards process (i.e. initiate SAR, collect industry comment, ballot etc). The SAC believes that certain parts of the process manual, (those dealing with process or procedures) should be changed by SAC, with approval by the Board of Trustees, and other parts (those dealing with fundamental tenets of the process) should only be changed with stakeholder recommendation and approval by the Board of Trustees. This SAR will allow needed changes to be made with less burden on the industry and without confusing process manual changes with standards development.

Status: The drafting team is considering comments from a posting of the proposed revision to the manual. A decision whether to ballot the revision or post a second draft is expected in August.

This bulletin is intended to provide recipients with the latest news concerning the development of NERC reliability standards. If you have any questions, comments, or suggestions on how we can improve our bulletin, please contact Gerry Cauley at Gerry.Cauley@nerc.net.

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Attachment 3

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

Interchange Authority Function White Paper

September 3, 2004

Version 1.4, Draft 2.0

NERC Interchange Authority Function Task Force

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Introduction

The Operating Committee charged the Interchange Subcommittee with operationally defining the Interchange Authority (IA) function. The Interchange Authority Function Task Force (IAFTF)[1] was formed to compile and address the outstanding issues surrounding the IA function, and define how the IA function would operate with the adoption of standards related to the NERC Reliability Functional Model (FM). This white paper:

- Defines how the tasks of an Interchange Authority will be performed operationally.
- Provides a common vision of the Interchange Authority.
- Describes how the Interchange Authority function interrelates with other functions – both market and reliability.
- Discusses the debatable issues, options, and concerns surrounding the Interchange Authority function.

Executive Summary

Today, Interchange Authority functions are performed by entities within the control area paradigm. The IA function as described in the FM is a concept — a listing of tasks — that requires detail before the industry places the IA into operation. The purpose of this paper to implement the concept of an IA into an industry that "operates" within the Functional Model. The paper defines the task force's vision of how the IA will operate, and how the IA will communicate and interrelate with the other FM functions.

The white paper discusses, and attempts to resolve, the debatable issues surrounding the IA function. These debatable issues are summarized in **Appendix D**, and have also been identified during the public postings of the FM, meetings of the Coordinate Interchange groups,[2] and various industry forums.

The IAFTF summarized its vision of the IA and includes a recommendation to apply the IA function for Version 1 Standards. The majority of the group believes that the recommendation represents the most logical and efficient way to fulfill the functions of the IA. The paper describes other options for a future IA that were considered as part of the discussions (**Appendix B**).

[1] The IAFTF roster is **Appendix A**.

[2] The Coordinate Interchange groups are NERC's Interchange Subcommittee and Coordinate Interchange Standards Drafting Team and NAESB's Coordinate Interchange Business Practice Task Force. This white paper was discussed at the Coordinate Interchange Standard DT meeting on September 8–9, 2004 (members of the NAESB Coordinate Interchange BP TF attended the meeting) and the discussion resulted in revisions to the paper. No action to "approve" the paper was taken at the meeting.

Interchange Authority Vision

Interchange Authority Purpose

The IA function serves as a gateway to translate the Purchase-Selling Entity's (PSE) or Market Assembler's (MA) Requests for Interchange (RFI) into physically implemented schedules between the Balancing Authorities (BA). The standards for the business and commercial aspects of the RFI are covered under the NASEB Coordinate Interchange Business Practice Standard, Version 1. The reliability entity responsibilities for facilitating the physical movement of energy will be covered under the NERC Coordinate Interchange Standard, Version 1.

Interchange Authority Functions

At a high level, the IA functions will:

1. Validate market-approved RFIs.
2. Distribute and obtaining confirmation of the RFIs from the reliability entities.
3. Authorize implementation of physical interchange transactions by the BAs.
4. Enter physical interchange transactions into any appropriate reliability assessment systems.
5. Maintain auditable records of physical interchange transactions.

A detailed description for each of these functions is contained in **Appendix C**.[3]

Interchange Authority Interactions and Communications

The diagram in Figure 1 (**Appendix F**) illustrates how the IA will interact and communicate to facilitate interchange. This diagram is based on Version 1 of the NAESB Coordinate Interchange Business Practices Standards and the NERC Coordinate Interchange Standard:

- The PSE or MA assembles all energy purchases, sales, and transmission service arrangements prior to communicating with the IA (NAESB RFI Standard 2.1).
- The PSE or MA verifies all energy purchase, sale, and transmission service market arrangements prior to communicating with the IA (NAESB RFI Standard 2.1).
- Upon receipt of all necessary market verifications, the PSE or MA submits a balanced RFI to the IA (NAESB RFI Standard 2.0).
- The IA will submit the balanced RFI to the reliability entities (RA, BA, TSP) for validation (NERC CI Standard 402).

[3] Information on the development of the Coordinate Interchange Standard may be found on the NERC website at: and NAESB Version 1 Business Practice Standards for Coordinate Interchange (RFI) may be found on the NAESB website at:

- The reliability entities will confirm the RFI for the IA (NERC CI Standard 403).
- After all necessary reliability confirmations, the IA will send the confirmed net interchange to the affected BAs for implementation (NERC CI Standard 401).
- After confirmation, the IA tool will also send the confirmed net interchange to the appropriate reliability assessment systems as identified by the reliability entities (NERC CI Standard – TBD).

Recommended Option for Fulfilling the Interchange Authority Function

Successful completion of IA tasks is critical to moving energy between BAs. Accurate and timely coordination of Interchange by the IA is also crucial to system reliability. The IA must be able to accept the market's RFI from the PSE or MA, distribute the RFI to affected reliability entities i.e., BA, TSP, RA, receive approvals from the reliability entities, and receive modifications to the RFI from market and reliability entities. IA communication on the status of Interchange to both market and reliability entities is of paramount concern to NERC because of its potential to affect system reliability.

The IAFTF believes the sheer volume, complexity, and multiple combinations of communication required to perform the tasks of the IA presents a coordination risk to the industry. The IAFTF believes the most efficient way to meet the reliability needs and expeditiously communicate the necessary data to all parties involved in physically moving energy between BAs for a Version 1 implementation is through today's E-Tag system, and for a future implementation the creation of single Interconnection-wide IA tools.

When considering industry efficiency, the IAFTF looked at the relevant experiences in implementing OASIS and E-Tag. One of the biggest problems encountered during these implementations was interoperability of systems due to variations in interpreting system functionality and technical specifications. The IAFTF believes the best way to eliminate interoperability problems is to develop a single Interconnection-wide IA tool. The IAFTF's recommends:

> *For Version 1, the IAFTF recommends that the IA be developed as an interconnection-wide medium for communications with the reliability entities. (See Interchange Authority Options section – Option 3.) Although the IAFTF has identified communication and coordination risks with this option the group feels it represents less risk than the other options. Using an Interconnection-wide medium for Version 1 is logical, and unavoidable, because the system exists today and is deeply ingrained within the industry.*

Interconnection-wide IA tools would:

- Minimize electronic communications between all involved parties. Multiple IA tools (or other methods of communication) will introduce unnecessary

complexities, time delays, and decreased flexibility. A single IA tool will inherently improve reliability of the interconnected system.
- Reduce response time between affected RA and BA entities when system emergencies arise that are directly affected by BA-to-BA transactions by reducing the number of communications required.
- Avoid interoperability problems by having a single interpretation of functionality definitions and supporting technical specifications.
- Since the IA tool design will require highly reliable and fully redundant systems, costs may be significant. A single IA would distribute that expense to all operating entities.
- Allow for an expedited rollout by eliminating interoperability testing and reducing the development and startup effort by the vendor.
- Allow for greater accessibility by various industry backend systems because of standardization.

The IAFTF attempts to consolidate the majority opinion of the group, and the options have been captured in **Appendix B**.

Certification – Training – Next Steps

Certification

How will the IA functionality be certified? The IAFTF recommends:

- Certification based upon the IA tool used to perform IA activities.
- Create a default IA tool for use by reliability entities.
- Certify the IA tool, by complying with a series of measures defined in a test procedure, requirements document.
- Every reliability entity would be required to provide IA functions. If the reliability entity has registered a URL to a certified IA tool, then they would be considered certified and meets requirements for proper practices as measured by the local reliability organization, then they would be considered certified.

Education

The IAFTF is concerned with the education and training of the industry regardless of the disposition of open issues. Adequate time must be allowed to address training for the successfully employing the IA function.

Next Steps

The IAFTF requests the Operating Committee use this white paper as a means to solicit further comments on the IA from NAESB, the ISO/RTO Council, NERC Functional Model Working Group, and other industry groups. Further, we recommend the Operation committee remand the whitepaper to the NERC Interchange Subcommittee to further development of detailed functionality and recommendations for tools.

Appendix A

NERC Interchange Authority Function Task Force (IAFTF)

John M. Simonelli, Chairman	ISO New England Inc.
Pete Harris	ISO New England Inc.
Deanna M. Phillips	Bonneville Power Administration
Albert M. DiCaprio	PJM Interconnection, L.L.C.
J. Roman Carter	Southern Company Services, Inc.
Donald P. Lacen	Public Service Company of New Mexico
Gordon Scott	NERC
Douglas E. Hils	Cinergy Corporation
Jim McIntosh	California ISO
Andy Rodriquez	PJM Interconnection, L.L.C.
Ed Davis	Entergy Services, Inc.
Al Boesch	Nebraska Public Power District
Mike Oatts	Southern Company Services, Inc.
Jim Hartwell	NPCC
Bert Gumm	Idaho Power
Jim Hansen	Seattle City Light
Bob Harshbarger	PSE
Karl Tammar	New York ISO
Larry Goins	TVA
Tim Ponseti	TVA
Joel Mickey	ERCOT

Appendix B

Interchange Authority Options

Option 1 – Tagging Extension Approach

Option 1 would build the IA around the E-Tag Authority concept. Today, Control Areas are responsible for maintaining an E-Tag Authority and that E-Tag Authority performs essentially all of the IA functions described in the FM. Each BA would register as an IA and perform both the BA and IA functions.

NAESB would prescribe the commercial functions needed for assembling an interchange transaction (See Market Period in **Attachment F, Figure 1**). The submitting Purchasing-Selling Entity or Market Assembler would send the completed balanced RFI to the ultimate Sink Balancing Authority's Interchange Authority (E-Tag Authority). That IA would be responsible for (See Reliability Period in **Attachment F, Figure 1**):

- Distributing the RFI to all affected reliability entities.
- Obtaining confirmation of the RFIs from the reliability entities.
- Distributing status of the confirmation process.
- Authorizing implementation of physical interchange transactions by the affected BAs.
- Forwarding interchange transaction information to the appropriate reliability assessment systems e.g., Interchange Distribution Calculator (IDC).
- Maintaining records of physical interchange transactions.

Pros:

1. Allow for continuity with current business practices and backend application software.
2. Minimizes industry wide implementation issues because of its similarities to today's paradigm.
3. Gives the same "look and feel" to the commercial sector of the industry.

Cons:

1. Requires that all BAs perform the IA function.
2. Requires the BA receive net interchange schedules from potentially many IAs, which introduces a communication and coordination risk.
3. A single IA would be unable to communicate an absolute net interchange schedule to any particular BA.
4. There would be a compliance and certification issue with multiple IAs in that the of a single IA to communicate the absolute net interchange to any particular BA would not be possible.
5. May carry over some of the interoperability and implementation issues experienced in current tagging processes.

Option 2 – Distributed Approach

Option 2 would allow any entity that passes the Interchange Authority Certification and registers with NERC to perform the IA functions. Upon competition of the commercial functions as prescribed by NAESB during the Market Period, the submitting Purchasing-Selling Entity would send the completed balanced RFI to the IA of its choice. Each IA would be responsible for those functions described in Option 1.

Pros:

1. Allow for industry flexibility in determining whom to use to provide IA functionality.
2. Allow for the IA to provide creative, innovative, and value added services.

Cons:

1. Requires the BA receive net interchange schedules from potentially many IAs, which introduces a communication and coordination risk.
2. A single IA would be unable to communicate an absolute net interchange schedule to any particular BA.
3. There would be a compliance and certification issue with multiple IAs in that the of a single IA to communicate the absolute net interchange to any particular BA would not be possible.
4. May create interoperability and implementation issues based on the multitude of different entities providing IA functionality.

Option 3 – Consolidated Approach

Option 3 would create a single NERC wide or interconnection wide IA. Upon competition of the commercial functions as prescribed by NAESB during the Market Period, the submitting PSE would send the completed balanced RFI to a defined IA. Each IA would be responsible for those functions described in Option 1.

Pros:

1. A single IA would reduces the volume of communication between:
   a. Multiple IAs that would exist in alternate implementations.
   b. IAs and reliability entities.
   c. IAs and market entities.
2. Allow the BAs to receive and communicate net interchange schedule with a single entity as opposed to multiple entities, reducing the communication and coordination risk.
3. Allow for a single vendor to deal directly with those entities developing the functional definitions and technical specifications, reducing interoperability and implementation issues.

Cons:

1. Could put the industry in an “all your eggs in one basket” position.
2. May stymie creativity and flexibility within the industry by forcing everyone to use the same centralized IA service.

Appendix C

Interchange Authority Functions

1. Validity Checking Function

Ensuring balanced, valid Interchange Transactions. The IA function ensures that the RFI is balanced and valid prior to physical delivery of energy. The defined validation checks below are taken from the NERC Functional Model. The checks are performed by reliability entities on the contract path identified in the RFI (Reliability Authority, Balancing Authority, Transmission Service Provider). Validation checks include:

1. The source MW must be equal to the sink MW allowing for loss accounting.
2. The Transactions are between valid sources and sinks.
    a. Verify that the BAs correlate with the Sink Point and Source Point in the interchange transaction.
    b. Verify that there is one, and only one, BA or Scheduling Agent (SA) listed per POR/POD segment.
3. There is a (continuous) transmission arrangement from the Source to the Sink.
    a. Verify that the POR/POD pairs are valid for the TSP.
    b. Verify that for each TSP and POR/POD segment that the BA is valid.
    c. Verify that the BAs shown as adjacent in the interchange transaction are adjacent to each other.
4. Ensure the requested up and down ramp rates can be met. This will be accomplished by providing the affected BA's with net schedule information so they may review and ensure that they have the physical assets available to meet the requested ramp.

The NERC Operating Manual defines a Transaction as "An agreement arranged by a Purchasing-Selling Entity to transfer energy from a seller to a buyer." Adequate information must be provided to enable the RA to properly assess the impact of a Transaction ready to "go physical" on the Interconnection.

When the IA receives approvals from the TSP, BA, and RA, those entities responsibility for performing validations, the responsible IA directs the BAs on the contract path to implement the Transaction. If any of these entities performing the validations does not approve the Transaction the responsible IA cannot authorize the implementation of the transaction.

2. Distributes and Receives Interchange Transaction Verification

Collect and disseminate Interchange Transaction approvals, changes, and denials. The IA tool will receive, collect, validate, maintain, and distribute the RFI status from the reliability entities (RA, BA, TSP) on the contract path. The status will be visible to all reliability entities as well as the requesting PSE or Market Assemblers (MAs) (i.e., author of the RFI).

When the IA receives approvals from the TSP, BA, and RA, those entities responsibility for performing validations, the responsible IA directs the BAs on the contract path to implement the Transaction. If any of these entities performing the validations does not approve the Transaction the responsible IA cannot authorize the implementation of the transaction.

3. Authorize Implementation of Interchange Transactions

Instruct appropriate BA's to Implement the Interchange Transaction. Once the IA tool has collected all necessary approvals, the IA will communicate the desired net interchange schedules that it has accumulated to the affected BAs for implementation.

The IA tool shall communicate to each BA:

- ⇒ The new net Interchange Schedule for the BA (in the case if multiple IA's no one single IA would have the absolute net for any particular BA).
- ⇒ The new net Interchange Schedule by external interface for the BA.
- ⇒ The new individual Interchange Transactions list by external interface for the BA.

The IA will also communicate the final approval status and implementation of the individual RFI's to the requesting PSE or MA (i.e., author of the RFI).

4. Enter Interchange Transactions into Appropriate Reliability Assessment Systems

Ensure all required reliability data is communicated to Appropriate Reliability Assessment Systems. Once the IA has obtained all necessary approvals, the IA shall communicate the interchange schedules to the BA's for implementation and forward the interchange schedule to designated reliability assessment systems as required by the various FM reliability entities (e.g., the IDC.).

5. Maintain Records of the Interchange Transactions

The IA tool will make RFI information available to RAs, BAs, TPs, and Market Monitors (as mandated by Governmental Authorities, Provincial and State entities or specific Market Operators). The IA tool will serve as the source of net interchange, net interchange by external interface, and individual interchange transactions for each BA. The IA must retain information communicated to the BAs to facilitate the enforcement of audit and compliance measures ensuring the IA has properly communicated balanced confirmed schedules to the BAs.

Appendix D

Interchange Authority Debatable Issues

Defining the Interchange Authority as a Tool

The Functional Model defines the WHAT functions the IA will perform, this leaves open the operational questions regarding HOW these functions will be performed. Would an IA tool:

- Actually perform each IA function?
- Perform some of the IA functions while allowing the responsible reliability entities to perform the remaining IA functions?
- Simply allow the responsible reliability entities to perform all of the IA functions?

For example, an IA requirement is the validation of ramp capability. Does the IA tool perform this function by checking ramp rates supplied by BAs against the ramp rate in the RFI, or does the IA tool forward the necessary data to the appropriate BAs who perform the actual ramp capability check? The Functional Model does not specify which entity would perform the IA tasks; it simply requires that the tasks be completed. As a tool, the E-Tag Authority does not perform all E-Tag functions as much as it facilitates the validations and approvals by entities on the E-Tag.

An Electronic Scheduling tool could be envisioned to be involved during three distinct time periods:

Note: NERC IA standards have no role in the commercial ahead-of-time activities. A transaction can be agreed upon months and this initial communications and conformations are not part of NERC's standards. The IAFTF provides the following to demonstrate the potential total performance requirements of such a system.

Ahead of Time

1. Receives request from Purchasing-Selling Entities and/or Market Assembler to implement RFI.
2. Submits all RFI's to the Reliability Authorities, Balancing Authorities, and Transmission Service Providers for approvals.
    - Receives confirmation from Transmission Service Providers of transmission arrangement(s).
    - Receives confirmation from Balancing Authorities of the ability to meet ramping requirements for submitted Interchange Schedules.
    - Receives confirmation from Reliability Authorities on the ability of the interconnected system to support the RFI.
3. Provides approved, valid, and balanced physical Interchange Schedules to the Balancing Authorities for implementation on a forward-looking time frame.

Real Time

1. Once Interchange Transactions have started, the IA will receive real-time Interchange Transactions changes curtailments and/or re-dispatch Interchange Transactions changes from:
   - Reliability Authorities to maintain reliability (e.g. IROL or OSL or frequency violations).
   - Balancing Authorities (e.g. interruptions due to generation loss or load interruption or excess generation).
   - Balancing Authorities or Market Operator as part of regional congestion management

2. The IA will inform all affected Transmission Service Providers, Reliability Authorities, Balancing Authorities and the requesting Purchasing-Selling Entities of curtailments and/or re-dispatch Interchange Transactions changes.

After the hour

1. Maintains and provides records of individual Interchange Transactions for the Balancing Authorities and Market Monitoring.
2. Accepts interchange transaction changes after the fact such as Emergency and Shared Reserve events.

Entity or Tool

The IA is a function comprised of several tasks. The entities performing these activities by default are responsible for ["by default" says they are responsible but "in part" implies they are not] performing the IA functions. The IAFTF believes that it is appropriate to specify the IA functions in terms of a physical standalone entity.

- Some support the concept that the IA is only a tool that will allow the designated entities to perform the IA functions. What the entity performing the IA functions is called is not relevant; therefore, one can conclude that any entity can simply designate their IA tool. For example, a Sink BA can designate their IA tool similar to how a CA can designate their Tag Authority Service today.
- Others believe the IA should be a standalone physically independent entity that will need to “own” the IA tool(s) and take responsibility for it, including financial responsibility in case the IA tool(s) fails to perform. The entity providing the IA functionality would then be subject to compliance and penalties.

Need for an IA Entity

Is the IA function actually needed under the FM since the BA can perform those functions? The IA, as defined in the FM, is a logical collection of actions or activities relating to the physical movement of energy between BAs. Since the CA in today’s world performs these functions, why can’t the BA under the FM perform these functions? The IAFTF believes that it is useful to specify the IA functions separately since they are associated with a specific set of actions and interactions.

- Supporters of the need for a unique IA believe its functions and ultimate responsibility under audit and compliance guidelines, requires a physically separate entity that can be held accountable. Folding the IA functions underneath another FM entity (most probably the BA) does not meet the definition and functional requirements of the BA. This would necessitate a change to the FM.
- Opponents of the requirement for an IA point out that BAs and only BAs should be responsible for the tasks, (note that today all BAs do serve as IAs), and therefore there is no need for an IA function and no foreseen problems if the IA is not established.

Singularity
One issue the IAFTF has struggled with is should there be a single interconnection-wide IA entity/tool? (See Recommendations and Options sections above).

- Some within the industry feel the IA function can be performed by any entity wishing to provide the service and demonstrating their ability to meet certification. In this case any number of legitimate entities can perform the IA functions. Supporters of the FM concept cite the NERC Board and the NERC SAR process that, “No commercial process be prohibited or mandated.” They note that each Control Area today serves as its own IA under the E-Tag paradigm. This allows for a potential infinite number of IAs, which should not be precluded.
- Opponents point to the potential for “too many” IAs and the risk of creating an unimplementable technical paradigm and a potential risk to reliability. They feel a single IA (or interconnection-wide IAs) would:
    - Reduce the number of actual electronic communications that need to occur between all involved parties,
    - Reduce response time between affected RA and BA entities when system emergencies arise.
    - Allow for a single vendor to deal directly with those entities developing the functionality definitions and supporting technical specifications.
    - Provide the most reliable and fully redundant system possible
    - Allow for an expedited rollout of the IA by reducing the development, testing and startup effort by centralizing on a single vendor.

New Functions/Requirements
Are the IA functions performed today? Some claim that all the activities associated with the IA function are carried out by today’s sink control areas; the sink control area performs those responsibilities using the E-Tag system, control area scheduling systems, and the control area-to-adjacent control area checkout of Net Interchange Schedules. Others claim that all new tools and methodologies will be required to implement the IA functionality.

- Supporters of the FM concept claim that all the functions are carried out today and that the responsibility is assigned today to the sink control area (i.e. sink BA); and that the sink control area carries out those responsibilities using the current E-tag supplemented by control area to adjacent control area checkout of Net Interchange schedules. The FM does not introduce any additional functions over and above what is performed today.
- Opponents claim that the injection of an independent entity performing the IA functions will require a new level of communication and new tools and methodologies may be required to support the IA functionality. As an example, the FM requires direct communication with each reliability entity both to ask for and receive individual approvals as well as direct communications to verify the final status of an RFI.

Inadvertent Energy
Does the IA function include the determination of inadvertent energy?

- Supporters feel that the IA functional role of keeping transaction records makes the IA a more cost effective in determining and reporting inadvertent for an interconnection.
- Others feel the determining and reporting of inadvertent activity belongs with the entities performing the BA function.

Appendix E

Interchange Authority Al DeCaprio Comments

System Implementation Issues

Ensuring System Reliability - The IA tasks (the WHATS) are critical to moving energy reliably between BAs. Reliably in this instance means the accurate coordination of the status of interchange information. The IA tasks (the WHATS) are performed today, the questions for the future are:

- How will the IA tasks be accomplished?
- Who will carry out the tasks?
- Who bears the responsibility for failure to carry out these tasks?

The first implementation requirement is for the IA to accept all in-coming interchange requests from PSEs or MAs.

HOW:

1. How is the requested information communicated?

   All interchange requests, called Requests for Interchange (RFI), are submitted to the E-Tag system and remain there until confirmed by all parties on the E-Tag. Today, some transactions may not be intered into E-Tag system (e.g. during Emergencies) and are handled directly by system operators.

   The Functional Model *allows for*, but does not mandate, a decentralized submission methodology. This could result in:

   - Multiple E-Tagging type systems (Issue is with inter-operability of such systems).
   - Non-electronic communications (Issues are:
     i. Too many non-electronic communications would impede the industry's ability to deal with and implement all schedules.
     ii. Too many non-electronic communications would impede operators ability to do complete analyses of the transactions.

   The Functional Model also *allows for*, but does not mandate, a centralized submission methodology. This could result in:

   - Only one transaction scheduling system (Issues are:
     i. Monopoly power of 'submission system operator.'
     ii. Difficulty in matching diverse tariffs.
     iii. Difficulty in matching different Market rules
     iv. Difficulty in matching different congestion management approaches.

v. Lack of flexibility.

2. How is the requested information confirmed or rejected?
   Each party to the E-Tag has the right to approve or deny a request through an E-Tag interface. Each party must explicitly provide their responses.

3. How is a confirmed transaction recognized?
   Once all parties to the transaction have approved a request, the E-TAG request is shown with an **Implement** status.

   The actual status of each request is available on the E-Tag provider's interface.

4. How is a 'request with an Implement status' finally implemented?
   Prior to implementation system operators total their individual transactions by adjacent area interface and check the net area interface schedule(s) with their respective neighbors.

The Functional Model *allows for*,but does not mandate, a decentralized communication methodology. This could result in:

- Multiple confirmation systems (Issue is on design methodology).
    - i. Will each methodology be forced to meet the individual needs of each operating system?
    - ii. Will each operating area be required to handle all of the various communications systems?

The Functional Model requires the status of each transaction that is validated must be individually communicated to all parties to the request. This could result in:

- One person calling all parties informing them of the final status. Such a process would be inefficient for the person doing the calls and for the system operator receiving multiple calls.
    - i. f NERC is only concerned with reliability and not concerned with actual or expected efficiencies then the IAFTF should not address the issue of efficiency?

From a reliability perspective the reliability entities need to communicate an approval or deny status. Reliability would be maintained but commerce would be hindered.

WHO:

1. Who submits a request?
   Each individual request is placed into the E-Tag system by the source or sink PSEs.

2. Who confirms/denies a request?
   All involved parties must provide an explicit response.

3. Who tracks the status of the request?
   All reliability parties must track the status of the request.

4. Who tracks the implementation status of the request?
   All reliability parties must track the status of the request.

   The sink BA is assigned the responsibility to ensure that the source BA (and by implication each BA in between) has the same information and status. However, that task is generally affected by adjacent BA checkout just prior to implementation.

WHO HAS RESPONSIBILITY TODAY:

1. Who has the responsible to submit a request?
   Requests are not a NERC issue; however, the PSEs submit interchange requests.

2. Who has the responsible for responding to a request?
   All reliability entities (RAs; BAs and TSPs)

3. Who is held responsible to transmit the ‘validated’ request?
   The physical task is accomplished through the E-Tag Authority. The E-Tag Authority bears no responsibility for the information in its system.

Today, ***reliability*** is maintained by area-to-area net schedule checkout with the understanding that transaction by transaction information is available to crosscheck the total.

Any individual transaction may be lost because the area-to-area data may be in error. No one is responsible for ensuring that the valid request is communicated to everyone.

4. Who is held responsible that a validated request is implemented?

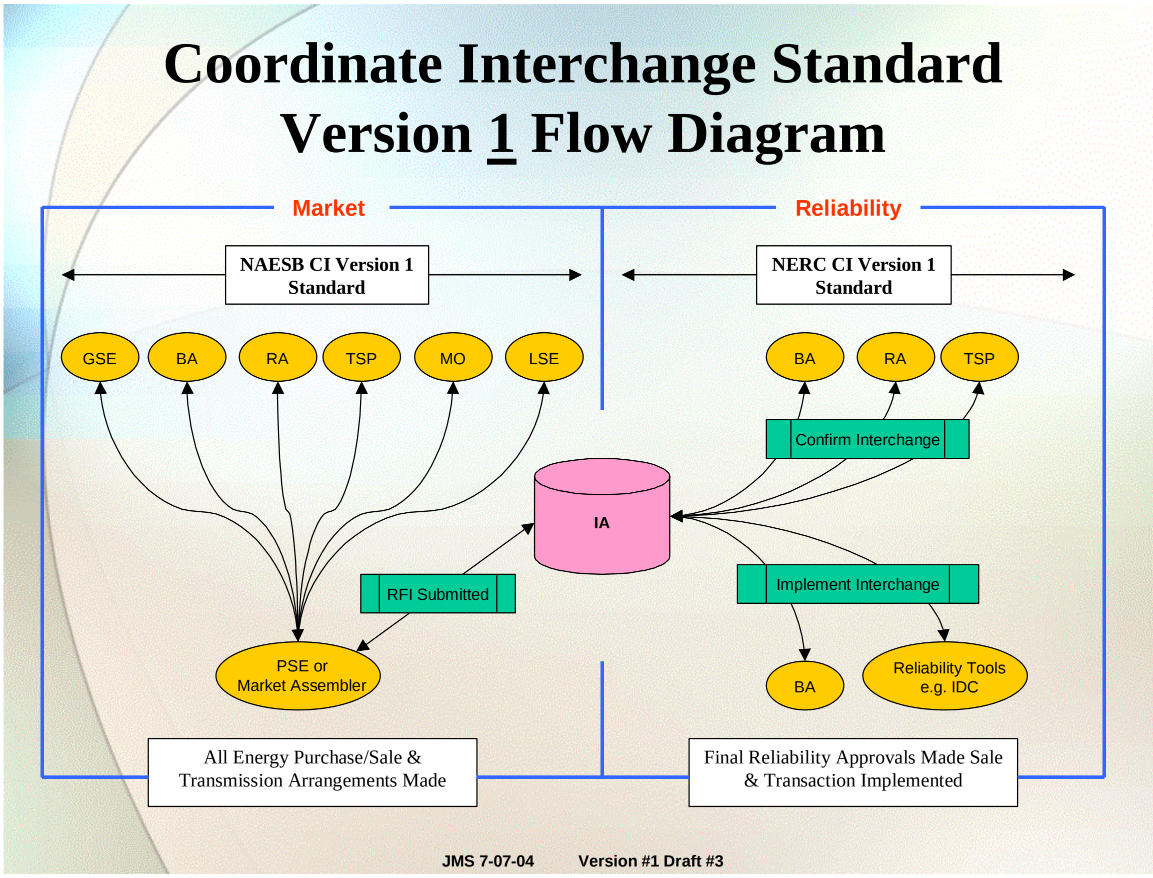
   The sink BA is responsible for ensuring that validated interchange schedules are implemented.

   Under the Functional Model the entity that has taken on the IA responsibilities shall comply with the IA-related standards. While the FM recognizes that the same entity that serves as the sink BA can also serve as the IA, the FM also allows for the IA to be a corporately independent entity selected by the sink PSE.

   Issue is with the fact that one sink PSE can select one corporate entity to do these IA tasks , while another sink PSE may select a second corporate entity and in the worst case, the nth sink PSE would select an nth corporate entity to provide the IA tasks. Is there a real difference between ‘N’ inputs to one hub with ‘M’ outputs vs. N-inputs to N-hubs each with one output?

Appendix F

Interchange Authority Figure #1


Coordinate Interchange Standard
Version 1 Flow Diagram
Market
Reliability
NAESB CI Version 1 Standard
NERC CI Version 1 Standard
GSE
BA
RA
TSP
MO
LSE
BA
RA
TSP
Confirm Interchange
IA
RFI Submitted
Implement Interchange
PSE or Market Assembler
BA
Reliability Tools e.g. IDC
All Energy Purchase/Sale & Transmission Arrangements Made
Final Reliability Approvals Made Sale & Transaction Implemented
JMS 7-07-04
Version #1 Draft #3

Attachment 4

Update from Roman Carter on V0 Drafting Team Actions
August 20, 2004

Related to Standard 10:

The V-0 SDT felt the recommendations proposed by the IS for requirements 1,2,3 were not appropriate for V-0. Policy 3 states that both the PSE and the Sink BA are responsible for their prescribed transactions and by ignoring this and only being interested in the Tag being submitted was too much of a change for V-0. They want the appropriate entities to be responsible for ensuring the Tag is submitted.

The group agreed that reliability is only concerned with the fact that the Tag is submitted. However, in V-0 we have to go beyond this and place "active" requirements on entities to make sure they are submitted.

Related to Standard 11:

The V-0 SDT accepted the IS's recommendations and incorporated those changes into the latest draft of the Standard.

Related to Standard 12:

The V-0 SDT accepted the IS's recommendations and incorporated those changes into the latest draft of the Standard.

Related to Standard 13:

The V-0 SDT rejected the changes proposed in Requirement 1 due to "Reliability Event" being too broad of an interpretation. Modifications to a tag for reliability sake should be limited to just the items outlined in Policy 3 Section D. This will prevent Reliability Entities cutting schedules in the name of "reliability" if it is truly not a reliability issue as described in current Policy 3. This appeared to be a problem in the past.

The V-0 SDT accepted the recommended changes to Requirement 2 and will incorporate them into the latest draft.

The V-0 SDT accepted the changes recommended in Requirement 5 with the exception to changing the TSP to TOP. According to Policy 3D, Requirement 2.0, the Transmission Provider has the right to make modifications. It was recognized that the TOP will be working with the TSP making recommendations about modifications, but, the TSP will be the actual entity requesting the modification.

The required modifications due to deviations in the dynamic schedule was discussed in much detail. The team agreed to post again for comment in draft 2 of the standard requesting Industry to make a choice between 2 options: 1) No change at all to current policy or 2) No modifications required for deviations up to 25 mws for transactions below 250 mws. For transactions greater than 250 mws, modifications would be required for deviations greater than 10% of the original transaction.

Appendix 3A4

The V-0 SDT recommended that NERC Appendix 3A4 be turned over to NAESB for their V-0 Standard. The reliability requirements contained within the Appendix will be put into the NERC V-0 standard as direct requirements so we will continue to include them in the Standard.

For Operating Committee conference call

August 11, 2004
3 p.m. EDT

NERC-NAESB Collaborative Proposal for Version 0 Business Practice Standards

Preliminary Results Based on Joint TF Meeting August 2-3, 2004

Background

At its July 16, 2004, meeting the Joint Interface Committee (JIC) reviewed proposals from the NERC Version 0 Drafting Team and the NAESB Business Practices Subcommittee (collectively "the drafting teams") for the assignment of Version 0 reliability standards and business practice standards. The JIC noted agreement between the two proposals on the vast majority of proposed Version 0 standards, including both reliability standards to be assigned to NERC and business practice standards to be assigned to NAESB.

There were, however, a few areas in which the proposals differed. The NERC drafting team considered a several of the proposed business practices to be too difficult to separate from the reliability requirements, requiring a substantial rewrite of the current NERC rules. A substantial rewrite of the current reliability rules is clearly not in the scope of the Version 0 project. The NAESB Business Practices Subcommittee accepted that position and recommended creating duplicate or "shadow" NAESB Version 0 standards in these areas to establish an equivalent baseline for developing future business practice standards.

The JIC took several actions at its July 16 meeting:

1. The JIC assigned to NERC the development of proposed reliability standards, as documented in NERC's July 9, 2004, Version 0 reliability standards posting.
2. For the proposed business practice standards agreed to by the drafting teams, the JIC deferred assignment of those to NAESB, pending discussions at the NERC standing committee meetings the following week and the August 9 close of comment periods for the NERC and NAESB postings. The JIC felt that waiting a few weeks to be informed by a broader set of industry stakeholder inputs would be beneficial.
3. For the third set of proposed standards, in which the NERC drafting team proposed to develop a reliability standard and the NAESB team proposed to develop a "shadow" business practice standard, the JIC requested NERC and NAESB to assign a joint task force of committee leaders to collaboratively reconcile the proposals into a common recommendation.
4. The JIC requested this joint task force, if possible, to bring a single NERC-NAESB recommendation to the JIC for approval on August 16, after the close of the public comment periods and before the two drafting teams meet to continue working on their respective Version 0 standards.
5. The JIC noted that NAESB was not expected to slow its timetable for developing its proposed Version 0 business practice standards.

Joint Recommendation

The NERC-NAESB joint task force met in Chicago on August 2-3 and prepared a proposal for assignment of Version 0 business practice standards as outlined below. The joint task force was successfully able to clarify the division of Version 0 reliability standards and business practices, such that there are no proposed duplicate standards, with one exception. The one exception is the Transmission Loading Relief (TLR) Procedure. The task force proposes that that NERC and NAESB adopt an identical TLR procedure document in their respective Version 0 standards and immediately begin a joint project to develop replacement Version 1 standards distinguishing reliability requirements and business practices by the end of 2005.

The task force will review the recommendation a final time on August 13 after an analysis of public comments received by NERC and NAESB. Because the standards in question are all derived from the NERC operating policies, the NERC Operating Committee is also being asked to review the recommendation prior to August 13. The joint task force will submit its final recommendation to the JIC on August 16.

The recommendation was endorsed by the participants on the task force from both NERC and NAESB. The task force members at the meeting were:

NERC	**NAESB**
Mark Fidrych, WAPA (OC)	Michael Desselle, AEP (NAESB Board)
Michel Armstrong, TransEnergie (OC)	Lou Oberski, Dominion (WEQ EC)
Terri Grabiak, Allegheny (MC)	Scott Brown, Exelon (WEQ EC)
Wayne Lewis, Progress (MC)	Phil Cox, AEP (BPS)
Scott Henry, Duke Power (SAC)	Joel Dison, Southern (BPS)
Gerry Cauley, NERC (V0 Drafting Team)	Andy Rodriguez, PJM (BPS)
Bill Lohrman, NERC (MC)	Rae McQuade, NAESB
	DeDe Kirby, NAESB

Recommended Assignment of Appendix 1A Sections B, C, and D (ACE Special Cases)

Proposed NERC Standard – The NERC Version 0 Drafting Team has incorporated the control performance standards (CPS1 and CPS 2) into proposed Standard 001. To make this standard complete, the drafting team incorporated the ACE equation, definitions to support the ACE equation, and specific reliability requirements from Appendix 1A into the standard.

Proposed NAESB Standard – The proposed NAESB Version 0 Business Practice Standard addresses treatment of special cases of the ACE equation in Appendix 1A: Section B – Pseudo-Ties and Dynamic Schedules for Jointly Owned Units); Section C – Supplemental Regulation Service; and Section D – Load or Generation Transfer by Telemetry. Reliability requirements in the NERC standards will not be duplicated in the NAESB standard.

References

- NERC Version 0 Reliability Standard 001
- NAESB Version 0 Standard
- Appendix 1A

Operating Policy 1D and Appendix 1D (Time Error Correction)

Proposed NERC Standard – The NERC proposed reliability standard addresses three elements from Policy 1D Requirement 4: 1) the Time Monitor for an Interconnection must be a Reliability Authority (RA); 2) any RA in the Interconnection may halt a time error correction for reliability considerations (before or during the correction); and 3) any Balancing Authority may request its RA to halt a time error correction for reliability considerations. This standard is derived from Operating Policy 1D Requirement 4.

Proposed NAESB Standard – The NAESB proposed business practice standard is the time error correction procedure, exclusive of the reliability elements noted above. This standard incorporates Operating Policy 1D (excluding Requirement 4) and Appendix 1D.

References

- NERC Version 0 Reliability Standard 004
- NAESB Version 0 Standard
- Appendix 1D

Operating Policy 1F (Inadvertent Interchange Payback Procedure)

Proposed NERC Standard – The NERC Version 0 Drafting Team has developed a standard that includes the reliability requirements for inadvertent payback. This proposed standard excludes the inadvertent payback procedure (Policy 1F Requirement 5 and Appendix 1F). The NERC standard retains the inadvertent accounting and metering requirements necessary for reliability. NERC will evaluate whether a distinct dispute resolution procedure should be retained for inadvertent interchange, or whether NERC's general dispute resolution procedure would be suitable, as suggested by the Version 0 Drafting Team. The Version 0 Drafting Team will be requested to incorporate Appendix 1F Section C – On Peak and Off Peak Periods – into the NERC standard.

Proposed NAESB Standard – The NAESB proposed business practice standard incorporates the inadvertent payback procedure in Policy 1F and Appendix 1F, with modifications to exclude reliability requirements noted above and addresses only the payback and business practice aspects.

References

- NERC Version 0 Reliability Standard 006
- NAESB Version 0 Standard
- Appendix 1F

Operating Policy 3 and Appendices 3A2, 3A3, and 3D

Proposed NERC Standard – The NERC and NAESB drafting teams were able to divide Operating Policy 3 into reliability and business practice requirements. NERC has proposed four standards on interchange addressing requirements for: tagging interchange transactions; assessing interchange transactions, communicating and implementing tagged interchange transactions; and modifying tagged interchange transactions. The NERC standards incorporate the tag timing requirements in Appendix 3A1. Omission of the tag data elements was an oversight and the drafting team will be requested to review Appendix 3A4 to identify tag data elements needed for reliability and incorporate them into the next posting of the Version 0 reliability standards.

Proposed NAESB Standard – The NAESB business practice standard is proposed to include the remaining portions of Policy 3 addressing business practice issues and Appendices 3A2 – Tagging Across Interconnection Boundaries, and 3A3 – Electronic Tagging Service Performance Requirements and Failure Procedures. Any tag data requirements in Appendix 3A4 not considered by NERC to be reliability requirements may be incorporated by NAESB into a business practice.

References

- NERC Version 0 Reliability Standards 010, 011, 012, and 013
- NAESB Version 0 Standard
- Appendices 3A1, 3A2, 3A3, and 3A4

Operating Policy 5C

Proposed NERC Standard – The proposed NERC standards address the reliability requirements of Operating Policy 5.

Proposed NAESB Standard – NAESB agrees to withdraw its proposed business practice in Version 0 that includes Operating Policy 5C requirement 2.1 and requirement 3.

References

None.

Appendices 9C1, 9C1B, and 9C1C

Proposed NERC Standard – NERC has proposed a set of standards that translates the entirety of Operating Policy 9 into reliability standards. The NERC Version 0 Drafting Team, although acknowledging significant business practices exist in the TLR procedures (Appendices 9C1, 9C1B, and 9C1C), believed that it was not possible in the time frame of the Version 0 project to rewrite the TLR procedure to separate reliability requirements from business practices. The drafting team proposes to incorporate the TLR procedure in its entirety into the Version 0 reliability standards, modified only to incorporate functional model language. The NERC drafting team will also request WECC and ERCOT to provide updates in Version 0 to Appendices 9C2 and 9C3 respectively.

Proposed NAESB Standard – NAESB proposes to adopt the TLR procedure (Appendices 9C1, 9C1B, and 9C1C) as a Version 0 business practice standard. The NAESB standard addresses only the Eastern Interconnection and does not propose to address WECC or ERCOT congestion management procedures.

Additional Considerations

1. NERC and NAESB should use the identical TLR procedure in their Version 0 standards.
2. NERC and NAESB should develop a joint plan for filing an update of the TLR procedure with the FERC.
3. NERC and NAESB should immediately begin a joint effort to update the TLR procedure to divide the reliability requirements and business practices and to incorporate other necessary improvements to the TLR procedure. The recommended target for retiring the duplicate Version 0 standards with the next version is end of 2005.

References

- Proposed Version 0 TLR Procedure
- Appendices 9C1, 9C1B and 9C1C

Attachment 8a

From: Nan Whiting [Nan.Whiting@nerc.net]
Sent: Wednesday, September 01, 2004 5:10 PM
To: standards@nerc.com; rbb@nerc.com; rbbru@nerc.com; nercroster@nerc.com
Subject: Draft 2 Version 0 Reliability Standards Posted for Comment
This email was sent to the nercroster List Serve

TO: REGISTERED BALLOT BODY
REGISTERED BALLOT BODY REGISTERED USERS
STANDARDS
NERC ROSTER

A second draft of the proposed NERC Version 0 Reliability Standards is now posted for comment through October 15, 2004.

The draft standards are available for download in five Acrobat files:

- 40 proposed operating standards - clean version
- 40 proposed operating standards - redline markup from first posting
- 15 proposed planning standards - clean version
- 15 proposed planning standards - redline markup from first posting
- Proposed glossary of terms used in the standards

Additional supporting materials developed by the Drafting Team will be available by September 3:

- Draft 2 comment form
- Consideration of comments from posting of draft 1 - summary issues
- Consideration of comments from posting of draft 1 - specific comments
- Markups of operating policies, appendices and compliance templates

You are strongly encouraged to review and comment on the proposed Version 0 standards. This is the final period for receiving comments. The next posting of the proposed standards on November 1 will be for voting.

Questions may be addressed to Gerry Cauley at gerry.cauley@nerc.net or 609-452-8060.

Thank you for your support and participation in the NERC standards process.

Gerry Cauley
Director - Standards

Attachment 9

August 17, 2004

Interchange Subcommittee Draft Responses –

to the industry's comments on Version 0 standards

The IS has drafted the following responses to aid the Version 0 drafting team in developing final responses to the industry's comments.

Comments for Template 010

Eric Grant and Phil Creech – Progress Energy 010 – R2	Will a new tag template be issued to conform with the functional entities? Will E-tag Spec need to be changed to implement this standard?
Response:	The E-Tag specification will be revised for Version 1 but not for Version 0. For Version 0 the E-Tag schema will be revised with the new Functional Model terminology, but the E-Tag specification will not be changed. Functional Model = E-Tag • PSE = PSE, GPE, TC • LSE = LSE, TC • TSP = TP • BA = CA (Scheduling Entity) • RA = RC/IDC (Distribution Only) • Market Operator/Resource Dispatch = CA Vendors may change the E-Tag GUI to reflect this change.

Ed Riley – CALISO 010 – R1	2.1 P3T3 goes directly to Level 4 violations. The CAISO agrees with the sanctions for a tag violation, but believes the practice as written is too stringent and there should be Level 1 through 4 violations. This should be identified as a Regional Difference.
Response:	The measure should ensure that all Interchange is E-Tagged and that the BA only enters into its ACE equation "composite approved" Tagged Interchange.
Scott Moore – Operating Reliability Working Group 010 – Regional Diff.	SPP has a Scheduling Agent Waiver and should be listed here also.
Response:	The DT agrees and will add the waiver to 010.
Roman Carter – SoCo 010 – R1	The first sentence in the requirement should say "The load-serving PSE shall be responsible for tagging all Interchange Transactions except for those identified as

	being required by the Sink BA". The second sentence should pick up here and say "These Interchange Transactions (those that are between BA areas) shall include all transfers that are….etc." Otherwise, Requirement 3 of this Std 10 conflicts with Req. 1
Response:	The LS PSE was deleted as the responsible entity from this requirement because the requirement is covered in NAESB's Version 0 RFI. R3 was deleted from this template and added to the bullets in R1. A note was added to R1 stating that E-Tags may be submitted by entities other than the LS PSE.
WECC ISAS – 010 – R1	This document excludes the Policy 3 requirement of redoing a tag if there is a change of 25%. By excluding this existing language you are changing the scope of this document and not living with the version zero " no change direction"
Response:	The proposed change is not a "change in direction" it is simply adjusting a "how to" for E-Tagging. The Interchange Subcommittee has received numerous requests to revise this E-Tagging procedure.

Ed Riley – CALISO 010 – R2	Change "exempt from tagging for 60 minutes" to "tagged within 60 minutes".
Response:	The revised requirement reads: Exempt from E-Tagging for 60 minutes from the time at which the Interchange Transaction begins, regardless of magnitude or duration.
Kenneth Wilson – WECC 010 – R2	This standard says INTERCHANGE TRANSACTIONS established to replace unexpected generation loss due to emergency transactions to mitigate SOL or IROL violations are exempt from tagging for 60 minutes. Present policy requires a tag to be submitted within 60 minutes. This changes the current standard.
Response:	The revised requirement reads: Exempt from E-Tagging for 60 minutes from the time at which the Interchange Transaction begins, regardless of magnitude or duration.
Ray Morella – First Energy 010 – R2, 3	References Operating Security Limit violation, should be SOL and IROL.
Response:	The DT agrees to change the requirement to SOL or IROL.
FRCC Additional Comments 010 – R2	Clarification of the following is required: *… such as through prearranged reserve sharing agreements or other arrangements…* Does this mean that reserves will need to be tagged is an entity is part of a reserve sharing group, or, does it mean reserves are tagged if purchased from another member of the reserve sharing group when the purchaser cannot cover their required reserves?

Response:	If serving native load with pooled resources it does not need to be tagged. If brought in from another CA it must be tagged. Roman will check Policy 3 but this probably needs to be changed. The V0 team will revise the requirement.
Roman Carter – SoCo 010 – R2	The requirement left out an important point contained within Policy 3 section A 1.2 under note 2.-"If a PSE is not involved in the Transaction, such as delivery from a jointly owned generator, then the Sink BA is responsible for providing the tag". This requirement should be added to Standard 10
Response:	The revised R1 defines who is responsible for providing the E-Tag.
WECC ISAS – 010 – R2	**Clarify the last sentence - Such interchange shall be "tagged within 60 minutes" from the time that the interchange transaction begins**
Response:	The revised requirement reads: Exempt from E-Tagging for 60 minutes from the time at which the Interchange Transaction begins, regardless of magnitude or duration.

Alan Johnson – Mirant 010 – Attachment 1	May need to either add more text or include some references for clarity. For example, "E-Tag System" is referenced for the first time. Where does one go to find out what this is? As another example, there is a reference to a NERC TLR event. Again, this needs to be defined or a reference (to the NAESB TLR Standard?) provided
Response:	The E-Tag specification will be one of the supporting documents that the IS will reference for V0. V0 DT may want to note which documents will be included in the standards and where they are located.
WECC ISAS – Template P3T3	**The P3T3 template goes directly to Level 4. The WECC ISAS agrees with sanctions for tag violations, but think the practice as written is too stringent and there should be level 1 through 4 violations**
Response:	The measure should ensure that all Interchange is E-Tagged and that the BA only enters into its ACE equation "composite approved" Tagged Interchange. IS should complete response

Comments for Template 011

Summary Comment: The template was revised to include the suggested wording.	
Al Boesch – NPPD 011 - 03	"Energy profile, including the ramp (ability of the generation to support the magnitude and maneuverability of the transaction" is not correct. Maneuverability is associated with generation. Please restate as: ·Energy profile (ability to support the magnitude of the transaction)

	·The ramp (ability of generation maneuverability to accommodate)
Response:	The DT agrees and revised the template.
MAPP Operating Subcommittee 011 – R1	"Security Analysis Services" is not a Functional Model entity - entity responsible for this process needs to be identified.
Response:	The requirement has been modified to clarify what SAS refers to; the requirement reads "Security Analysis Services (IDC or other regional reliability tools).
WECC ISAS 011 – R1	The language needs to be clear that the generating entity receives the tag. We understand that NERC will hand off the tagging requirements to be covered in the NAESB standard but feel this needs to remain in this version zero document.
Response:	Needs IS response. This is clearly a business practice requirement and is in the NAESB V0 Standards. The generating providing PSE is provided a copy of the tag.
Deanna Phillips – BPA 011 – R1	Please modify this requirement to ethe need to provide this information to the Generation Operator, as required in Policy 3A Requirement 2.2. Without this information, the Generation Operator has no way of ensuring that tags were not submitted for his generator to produce more services than it either contracted to provide or is able to provide at the time**.**
Response:	Needs IS response. This is clearly a business practice requirement and is in the NAESB V0 Standards. PSE that provides generation should notify the Generator Operator.
Deanna Phillips – BPA NEW Requirement	Add a requirement requiring Generation Operators to communicate their approval or denial of the tag; in much the way as those requirements for the BA and the TSP to approve or deny the tag. This requirements is part of Policy 3A Requirement 4. Addition of this requirement is necessary in order to make the requirements of Version 0 the same as those of Policy 3 in this regard.
Response:	Needs IS response. This is clearly a business practice requirement and is in the NAESB V0 Standards.

Al Boesch – NPPD 011 – 04	The numbering sequence skips R4.
Response:	The numbering has been corrected.

Alan Johnson – Mirant 011 – R2	The following text from Policy 3A, Requirement 4 should be inserted at the end of the first sentence: "based on established reliability criteria and adequacy of Interconnected Operating Services and transmission rights as well as the reasonableness of the Interchange Transaction Tag."

Response:	The DT believes that in the TSP's assessment of the Interchange will take into account the reasonableness of the submittal. Adding the language would be superfluous.
Martin Huang – BCTC 011 – R2	This check can be automated to check the tag Market Path Product with the Transmission Allocation Product but this will only verify that the two codes select are compatible, it will not confirm that the actual Transmission is of the selected product. This being the case and with no or very limited impact to system reliably for a non match this check is unnecessary. Firm Energy being curtailed because its on Non-Firm Transmission becomes a settlement issue between the Generating and Load PSEs.
Response:	As R2 states, it is the TSPs responsibility for assessing and approving Interchange, including the energy profile and transmission priority.
Roman Carter – SoCo 011 – R2	Bullet 4 should say "OASIS reservation accommodates ALL Interchange Transactions" vs. multiple Interchange Transactions.
Response:	The DT agrees and the change has been made.
WECC ISAS 011 – R2	Losses are tagged separately in the WECC and we do not use the losses portion of the tag in its current form. WECC ISAS would ask for a regional difference to accommodate our current practice.
Response:	The DT does not believe a waiver is necessary. As long as the losses are E-Tagged, the WECC is complying with the requirement. IS review response.
Peter Brandies – NY ISO 011 – R2	A new task "Connectivity of adjacent Transmission Service Providers" is added for verification and assessment by the Transmission Service Providers in order to approve or deny an Interchange Transaction. Transmission Service Provider should be changed to Transmission Operator. **The 4th bullet should be amended to read "all interchange transactions" not "multiple interchange transactions".** **The 5th bullet is not included in existing policy - it makes sense to include it however it is a new requirement.**
Response:	The contract path is through TSPs not TOs. All was added to bullet 4. The numbering was changed.
NPCC, CP9 Reliability Standards Working Group 011 – R2	A new task "Connectivity of adjacent Transmission Service Providers" is added for verification and assessment by the Transmission Service Providers in order to

	approve or deny an Interchange Transaction. Transmission Service Provider should be changed to Transmission Operator. The 4th bullet should be amended to read "all interchange transactions" not "multiple interchange transactions". The 5th bullet is not included in existing policy - it makes sense to include it however it is a new requirement.
Response:	The contract path is through TSPs not TOs.. All was added to bullet 4. The numbering was changed.
Ed Riley – CALISO Regional Differences	Losses are tagged separately in the WECC and the CAISO does not use the losses portion of the tag in its current form. The CAISO would like to add "WECC Losses Waiver" to identify this Regional Difference.
Response:	The DT does not believe a waiver is necessary. As long as the losses are E-Tagged, the WECC is complying with the requirement. IS review response.
SRP – 011 – R3 or NEW #3	There are some important missing reliability considerations that are in the existing Policy 3 that should be included in Version 0 as requirements. Reliability Authority or perhaps even Balancing Authority tag assessment should ensure that proposed interchange transactions or schedule changes do not knowingly cause any other systems to violate established operating reliability criteria. (Current NERC Policy 3 B, 4.1.2)
Response:	In this instance the responsibility for system reliability is part of the requirements of the RA or TO as part of the approval process [Prior to E-Tagging].
SRP – 011 – R3 or NEW #3	Reliability Authority or Balancing Authority tag assessment should ensure that proposed interchange transactions or schedule changes do not cause the maximum Net Scheduled Interchange between BA's to exceed the total capacity of facilities or the established network Total Transfer Capability (TTC) between the BA's (Current NERC Policy 3 B, 5.1-5.2). Total Capacity of Facilities and TTC should be added as defined terms.
Response:	Should be addressed in the RA requirements as part of the approval process [Prior to E-Tagging].

Comments for Template 012

Summary Comment:	
Peter Brandies – NY ISO 012 – R1, 2, 3	The reference for the last bullet should be Policy 3B, Requirement 4.1.3 instead of Policy 3C, Requirement 3.4. The reference should be Policy 3B, Requirement 1 instead of Policy 3B, Requirement 4.1.3. The reference should be Policy 3A, Requirement 6 instead of Requirement 1.
Response:	DT to review.

MAPP Operating Subcommittee 011 - R1 R2 R3	Incorrect existing document reference: "Policy 3C Requirement 3.4" should be "Policy 3B 4.1.3" Incorrect existing document reference: "Policy 3B Requirement 4.1.3" should be "Policy 3B Requirement 1" Incorrect existing document reference: "Policy 3B Requirement 1" should be "Policy 3A Requirement 6
Response:	DT to review.
NPCC, CP9 Reliability Standards Working Group 012 – R1, 2, 3	The reference for the last bullet should be Policy 3B, Requirement 4.1.3 instead of Policy 3C, Requirement 3.4. The reference should be Policy 3B, Requirement 1 instead of Policy 3B, Requirement 4.1.3. The reference should be Policy 3A, Requirement 6 instead of Requirement 1.
Response:	DT to review.

Comments for Template 013

Al Boesch – NPPD 013 – R1	According to the functional model the Transmission Operator is the transmission entity involved in transmission modifications for reliability events. The Transmission Service Provider should be removed and replaced by the TOP
Response:	The drafting team replaced the TSP with the TOP.
Roman Carter – SoCo 013 – R1	Should have the TO vs. TSP in the requirement.
Response:	The drafting team replaced the TSP with the TOP.
MAPP Operating Subcommittee 013 - R1	This attempt at condensing the original policy wording has resulted in responsibility of entities becoming potentially unclear. For example, more than one entity may assume they have responsibility for setting the limit for a given

  013 – R1 013 – R2 013 – R3	situation or no one may assume responsibility. The concept that modifications "may be made only due to TLR events (or other regional congestion management practices), Loss of Generation, or Loss of Load." in Policy 3D Requirement 2 did not get translated into Version 0. Appears to disagrees with Policy 3D Requirement 2.3 which is applicable to the Source BA. If this is not the case, the this requirement on the Source BA did not get translated into Version 0. Using the words "release the limit" does not include the situation where partial reloading is required.
Response:	The original R1 and R2 were deleted, as they were redundant and not worded as requirements. See alternate wording for R1 and R2. R3 – The DT revised the wording to "reload" [See Raymond Vice comments below]. IS review response.

Summary Response: The DT believes the most efficient revision is: Where a dynamic schedule is in place between Balancing Authorities, a modification is required when: • If the transaction is 100 MW or less and the deviation is more than 10 MW. • If the transaction is greater than 100 MW and the deviation is greater than 10%.	
Peter Brandies – NY ISO O13 – R4, 5	- This requirement includes the existing PSE responsibility for updating tags associated with dynamic schedules where they deviate by more than 25%. The drafting team is asking for acceptance of new criteria however a question is still raised whether for transactions >100MW the requirement is 10% or 25%. Which of this is required or appropriate. - The reference should be Policy 3D, Requirement 2.5.
Eric Grant and Phil Creech – Progress Energy 013 – R4	The Drafting Team proposed improvement is acceptable. I still have reservations with the fact that this standard could require me to re-tag a firm dynamic transaction in a window that would cause it to be treated as non-firm for curtailment purposes during TLR. In addition, large balancing authorities which do not have to tag internal transactions, and thus are not subject to this standard, may cause harm to smaller neighboring balancing authorities which are subject to this standard.
Ed Riley – CALISO 013 – R4	The CAISO agrees with the drafting team proposal.
FRCC Additional Comments 013 - R4	The Drafting Team asked commenters if they agree with the modified structure of requirement R4. We believe it is important that no changes are made to existing policy with the

	translation to Version 0. Any modified format should be considered in Version 1, but we do not agree with the format provided. The minimum requirement to change a tag should be at least 25 MW in both cases (above and below 100 MW). If the Drafting Team wants better resolution of Dynamic Interchange Schedules, then tagging requirements for changes could be eliminated if the actual dynamic value was provided to the RA then the RA would place the value into the IDC and there is no doubt about dynamic Interchange Schedule actual value.
NPCC, CP9 Reliability Standards Working Group 013 – R4 R5	- This requirement includes the existing PSE responsibility for updating tags associated with dynamic schedules where they deviate by more than 25%. The drafting team is asking for acceptance of new criteria however a question is still raised whether for transactions >100MW the requirement is 10% or 25%. Which of this is required or appropriate. - The reference should be Policy 3D, Requirement 2.5.
Response:	DT to review R5
Alan Johnson – Mirant 013 – R4	Agree in concept with the proposed modification, but would like some technical support for the proposed breakpoints. It seems that should probably be addressed as a Version 1 modification.
Deanna Phillip – BPA 013 – R4	We agree with the modified language on when the tags for Dynamic Schedules must be modified.
Howard Rulf – We Energies 013 – R4	Drafting Team proposal for Dynamic Schedules: Make the low MW schedule cutoff for an allowed 10MW deviation 40 MW rather than 100 MW. This maintains the 25% allowed deviation down to 40 MW rather than changing it abruptly to ~10% for a schedule just below 100 MW.
John Blazekovich – Exelon 013 – R4	Exelon Corporation has commented on changing the dynamic interchange schedule requirements several times in the past (when the opportunity to comment was available). With that said we do not believe Version 0 is the time to make the obvious needed change (once the door is opened for this change you will not be able to shut the door on other changes), therefore we suggest this change be implement in Version 1.
SRP – 013 – R4	The proposed dynamic interchange schedule language (included in Draft 0 comments column) should be adopted.
Scott Moore – Operating Reliability Working Group 013 – R4	We concur with the changes proposed by the DST and further agree to the 10% criteria for transactions larger than 100 MW.

Roman Carter – SOCO 013 – R4	The V-0 DT asked for comments on modifications to dynamic schedules. It is recommended that for transactions =<100 mw, deviations of 10mw or less should not require modifications to the tag. For transactions > 100 mw, modifications to a tag should only be required for deviations greater than 25%.
Gayle Mayo – Transmission Policy Access Study Group	For the TAPS Group, many with smaller loads and transactions, a change in deviation threshold from a percentage to MW value may be preferred. However, Version 0 is a translation of current policies only. For Version 1, a preferred change would be a straight MW deviation threshold level. This approach would maintain reliability and not overly burden small users with no added reliability increase.
MAPP Operationg Subcommittee 010 – 013 010 Measure	It appears that Policy 3 A Requirement 1.1, which is identified in the marked up file as reliability, did not get translated into Version 0 Reliability Standards. There is no measure for the requirements applied to the Purchasing-Selling Entity in R1 and R4.
Response:	DT to address.

<table>
<tr><td colspan="2">SRP –
013 – R1, R4

It may be a good idea to clearly define some requirements on establishing a reliability limit. If it is not proper to allow denial of a tag cutail request then perhaps that should be spelled out in the requirements. Tag cutail requests currently qualify for passive approval even if late yet an entity could deny the request. The NERC Interchange Subcomittee addressed this issue in a letter submitted on 6/10/02.
From NERC IS letter. Curtailment orders may be denied only for the following two reasons: 1. The order requests actions in the past (for example, an order to curtail a transaction five minutes ago). 2. The order for curtailment cannot be reliably implemented.
In either case, the denying party should immediately issue its own curtailment order
To effect the curtailment transaction.</td></tr>
<tr><td colspan="2">Response: GLS will send the letter to Roman. The letter may need to be reissued or as part of the reference material for V0. The DT should look at drafting a requirement for the SRP concern.</td></tr>
<tr><td colspan="2">Response: This modification was made.</td></tr>
<tr><td colspan="2">Summary Response: The DT should review the items below.</td></tr>
<tr><td>Raymond Vice –
SERC Additional Comments
010 - 013</td><td>SERC Compliance Subcommittee Comments
Standard 010
Revision 0</td></tr>
</table>

	- General - We support having the requirement to submit a tag, and the minimum timing of such submission as a reliability standard, due to the importance of accurate scheduling to reliability. - Measures - The existing measure should be designated as M1, and another measure added. The additional measure, M2, should measure how well the PSE followed the requirements of this standard. M2: A PSE shall meet 100% of the tagging requirements for all scheduled interchange for which it is responsible, and do so in a timely manner. - Requirement 8 - The Existing Document Reference should be Requirement 4 rather than 4.2. There is no 4.2. - Compliance Monitoring Process - The monitoring process for this standard should be a tag survey when requested by the OC, during a compliance or readiness audit or investigation of unusual conditions. - Levels of Non-Compliance - For M1, should be based upon the number or percentage of non-tagged transactions. - For M2, should be based upon either the number or percentage of non-tagged transactions, or upon the number of late tags submitted. - Compliance Monitoring Process and Levels of Non-Compliance - Although I realize that the version 0 team is not adding these sections to the text at this time, I think that it is important that issues related to compliance be addressed early in the standards drafting process. **SERC Compliance Subcommittee Comments** **Standard 011** **Revision 0** - General - We support having the requirement to assess interchange transactions as a reliability

	standard, due to the importance of accurate scheduling to reliability. • Applicability o Either the Reliability Coordinator should be included in the applicability section, and have a requirement describing the criteria for assessing interchange transactions prior to approval, or the Reliability Coordinator should not be included in Requirement R1 as one of the entities who is to be provided the tag for assessment. • Requirement 1 o Having the RA and the Security Analysis Service as entities to receive the interchange transaction is redundant if the RA is supposed to receive the transaction via the IDC. If the RA is to have approval rights, the RA should receive the transaction prior to approval. If the RA is provided the tag for information purposes only, after approval by the other entities has been completed, the RA does not need to be included in R1. • Requirement 2 o OASIS reservation accommodates multiple Interchange Transactions. This is not clear. Should be reworded to indicate that the transmission reservation indicated on the tag must be sufficient to accommodate the energy profile of all interchange transactions that use that reservation in aggregate. • Compliance Monitoring Process and Levels of Non-Compliance o Although I realize that the version 0 team is not adding these sections to the text at this time, I think that it is important that issues related to compliance be addressed early in the standards drafting process. o The BA, or TO is 100% compliant with this standard when they provide documentation of their approval criteria for interchange transactions, and documentation of their approval process. This should be done during the compliance or readiness audit, or during an investigation. o The BA or TO would be non-compliant based on either their lack of documentation

	for their approval criteria, or their inability to demonstrate that they have an approval process that is used. Probably there would only be two level of non-compliance needed for this standard.
	
	SERC Compliance Subcommittee Comments
	Standard 012
	Revision 0
	
	• General
	  o We support having the requirement to confirm interchange transactions as a reliability standard, due to the importance of accurate scheduling to reliability.
	• Purpose
	  o The word AGC should be removed.
	  o
	• Requirement 1
	  o It seems unnecessary to have both "the Balancing Authority's AREA CONTROL ERROR equation or in the system that calculates that Balancing Authority's AREA CONTROL ERROR equation." Either the BA's ACE, or the system that… would be adequate to convey the meaning of the sentence.
	  o In the discussion of default ramp rates, there should be some indication that the Balancing Authorities can agree to a ramp duration other than the default. In sub-bullet (c), the text should be changed to indicate that ramp durations may be shorter than the default but must be identical <u>and agreed to by</u> the sending and receiving Balancing Authorities.
	• Compliance Monitoring Process and Levels of Non-Compliance
	  o Although I realize that the version 0 team is not adding these sections to the text at this time, I think that it is important that issues related to compliance be addressed early in the standards drafting process.
	  o I propose the following measures for this standard:
	    ▪ M1: the BA can provide

	documentation that agreements are in place with neighboring Bas as to how schedule confirmation will be performed. ▪ M2: the BA can provide evidence showing that for a random sample of X hours, confirmation was performed according to agreements before the schedule change began. These could be done via self-certification, during the compliance or readiness audit, or in response to an investigation. o For M1, Level 1 would be process in place but not documented, level 4 would be no process in place. o For M2, the level of non-compliance would be related to either the number or percentage of schedules not confirmed during random sample. **SERC Compliance Subcommittee Comments** **Standard 013** **Revision 0** • General o We support having the requirement to modify interchange transactions as a reliability standard, due to the importance of accurate scheduling to reliability, and the importance of keeping the information in the IDC up to date with changes to interchange transactions. • Requirement 2 o Both the Source and Sink BA are responsible for implementing the required modifications, not just the Sink. o Also, the Sending and Receiving Balancing Authorities should be responsible for re-confirming their interchange schedule when a modification takes place. This requirement should also include the fact that all Balancing Authorities, Transmission Service Providers, Reliability Authorities (if these are to be included in standard 11), and Security Analysis Service are to be notified of the

	modification as soon as possible. • Requirements 3 o Change “allow reloading” to “reload”. Change “release of the limit” to “reload”. Should include the requirement that the Source and Sink BA are responsible for reloading the transactions, that the sending and receiving Bas should re-confirm upon receipt of the reload instruction, and that all the Balancing Authorities, Transmission Service Providers, Reliability Authorities (if these are to be included in standard 011) and Security Analysis Service are to be notified of the reload as soon as possible. • Requirements 4 o The proposed language is superior to the language in the current version of Policy 3. We would support changing R4 to include the following as proposed by the Version 0 drafting team. “A Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall modify the tag when the energy profile deviates from the previously tagged profile as follows: - The transaction is 100 MW or less and the deviation is more than 10 MW; or – The transaction is greater than 100 MW and the deviation is greater than 10 %. • Compliance Monitoring Process and Levels of Non-Compliance o Although I realize that the version 0 team is not adding these sections to the text at this time, I think that it is important that issues related to compliance be addressed early in the standards drafting process.

List of questions and comments:

1. **The drafting team carefully reviewed the SAR associated with this standard and believes that all the listed requirements have been met in the four requirements included in the standard (see CI Standard Reference Document Appendix A). Do you agree?**

Summary Consideration: The intent of the Coordinate Interchange Standard is to address the reliability data and communications needed to implement Interchange. This Standard does not address the business practices commercial entities will use to assemble the data and obtain the approvals needed for Interchange.

In the past, NERC facilitated the industry by defining reliability practices and related business practices that were needed to assist in the communications needed for reliable system operations. Now, NAESB will write the business practices and the RTOs and Regions will define the commercial guidelines.

Although the drafting team believes that the standard adequately defines the reliability practices for Interchange, the associated business practices are needed to ensure the process for implementing Interchange is harmonized. NERC, NAESB, and the IRC must coordinate the rules for Interchange, which includes tools, timing, formats and methods.

Question – Which of the two paragraphs (or should neither) below should be added to the summary consideration? Should the statement be added to the reference document?

This standard does not impose any reliability requirements on the PSE. If the PSE does not comply with the reliability requirements of the RAs, BAs, and TSPs then the PSE's Proposed Interchange would be rejected during the IA verification process per requirement 402. The standard is predicated on the basis that RAs (RTOs, control areas, ISOs) BAs and Regions will impost their respective reliability requirements. Thus, "before" the PSE completes a Proposed Interchange the PSE must understand and respect the reliability and commercial rules of all parties it desires to do business.

This standard will provide the "What" data required for interchange; NAESB will provide the "How." Should 402 be moved up in the Standard as 401 as this is the first step in the process (defining what data is required to be submitted? Add the requirement that the PSE is required to submit reliability information and if this reliability information is not submitted to the IA the Interchange is not approved.

In the past NERC facilitiated the industry by defining the market practices. Now, NAESB should write the business practices; therefore, the PSE submittal is under the purview of NAESB . NERC and NAESB must coordinate the rules for interchange, which includes tools, and timing.

The intent of the Standard Is to address the what not the how. The commercial guidelines are to be defined by the RTO, and regions. In this Standard the PSE must be required to meet the guidelines of the e.g. WECC. The Standard is written to allow regions to define the rules. NERC responsibility is to write the reliability practices.

The NAESB standards state that there is a certain amount of reliability information, and NAESB will say as mentioned in the NERC standard. We need to have somewhere what are the reliability requirements of the PSE.

What is the purpose of this standard (or all the NERC Standards)? There are a number of items in the reference document that are not in the standard.

For operators there will be the same information as exist today.

In the introduction we should say here are the reliability requirements that the IA needs to approve an interchange.

We need to educate people – we should sit down a write what we have just outlined. This will be added to the reliability guidelines below.

The PSE is required to submit X information. There may be additional information that should be submitted.

The standard must have the minimum of what is needed for interchange to flow. We need a logical step by step process that states what the PSE does and the IA does etc.

The RA, markets, and regions will define the market rules for interchange. The PSE must meet each of the rules.

Don't start with the PSE but start with the markets.

NAESB will provide the minimum amount of data that NERC will define, to do business with a region or company then they may want that and can require that. This standard must include the standard data from the PSE to the IA.

The 402 requirements should be part of the standard. Do we need to say to the industry that they can have their separate rules? We may not be seeing that well enough in the standard. The problem with adding another requirement is that, with the format we have, is how to do the compliance. The IA may reject the interchange if the data is not submitted. The tool that is needed for interchange requires a large amount of data.

Put something on the first page – in the document. Need a bullet that refers them to the NAESB information – reference to the how. NAESB and FERC (tariffs) will define what is needed for market data. Need to move 402 up in the standard to say here is what is required to be submitted.

If entities find market rules too restrictive then they may file with FERC etc. To put more criteria in the standard would be adding how to the standard. We should not move away from what the standard is meant to say.

For reliability there is a need for X amount of data, that is what this standard is all about, we do not need (in this standard) to take this further. All RAs (not the BAs) on the path must agree to flow the interchange because they are the ones responsible for reliability.

May need NAESB amd NERC items in one document (users manual) to show the industry that everything is covered. This may help cut down on the confusion.

The PSE is required to submit reliability information and this is specified in 402. If the reliability information is not submitted to the IA the interchange is not approved.

Summary Consideration: This standard does not impose any reliability requirement on the PSE, because if a PSE does not comply with the reliability requirements of the RAs, BAs, and TSP then the PSE's proposed interchange would be rejected during the IA approval process of requirement 402.

The standard is predicated on the basis that RAs (RTOs, control areas, ISOs), BAs and Regions will impose their respective reliability requirements.

Thus "before" PSE puts together a proposed interchange, that PSE must know and respect the reliability and commercial rules of all parties it wants to do business with.

(GLS to add the statement above to the beginning of the Reference document).

Commenter(s)	Yes	No	Comments
Karl Tammer for RTO/ISO Council (9)	1	1	We agree that the SAR requirements are materially met in the four requirements in the standard. The standards may be strengthened by adding some of the specificity and detail contained in the Reference Document to the Standard.

[1] **The team is unsure which items in the reference document you reference. This Standard does not address and should not include the business practices commercial entities will use to assemble the data and obtain the approvals needed for Interchange.**

The team is unsure which items in the reference document you reference.

Commenter(s)	Yes	No	Comments
Ed Riley-CA ISO, CA SO	1	1	We believe that the standard should include the reliability-focused obligations of the PSE's as stated on Page Five of the SAR.

[2] **This standard does not impose any reliability requirements on the PSE. If the PSE does not comply with the reliability requirements of the RAs, BAs, and TSPs then the PSE's Proposed Interchange would be rejected during the IA verification process per requirement 402. The standard is predicated on the basis that RAs (RTOs, control areas,**

ISOs) BAs and Regions will impost their respective reliability requirements. Thus, "before" the PSE completes a Proposed Interchange the PSE must understand and respect the reliability and commercial rules of all parties it desires to do business. **This standard does not impose any reliability requirement on the PSE, because if a PSE does not comply with the reliability requirements of the RAs, BAs, and TSP then the PSE's proposed interchange would be rejected during the IA approval process of requirement 402.** **The standard is predicated on the basis that RAs (RTOs, control areas, ISOs), BAs and Regions will impose their respective reliability requirements.** **Thus "before" PSE puts together a proposed interchange, that PSE must know and respect the reliability and commercial rules of all parties it wants to do business with.**			
Bert Gumm-Idaho Pwr		1	It is felt the Standard does not adequately address the obligation of the PSE to submit reliability data information for energy transactions. The PSE's responsibility for information submission should be defined
[3] **This standard does not impose any reliability requirements on the PSE. If the PSE does not comply with the reliability requirements of the RAs, BAs, and TSPs then the PSE's Proposed Interchange would be rejected during the IA verification process per requirement 402. The standard is predicated on the basis that RAs (RTOs, control areas, ISOs) BAs and Regions will impost their respective reliability requirements. Thus, "before" the PSE completes a Proposed Interchange the PSE must understand and respect the reliability and commercial rules of all parties it desires to do business.** **This standard does not impose any reliability requirement on the PSE, because if a PSE does not comply with the reliability requirements of the RAs, BAs, and TSP then the PSE's proposed interchange would be rejected during the IA approval process of requirement 402.** **The standard is predicated on the basis that RAs (RTOs, control areas, ISOs), BAs and Regions will impose their respective reliability requirements.** **Thus "before" PSE puts together a proposed interchange, that PSE must know and respect the reliability and commercial rules of all parties it wants to do business with.**			

Gregory Campoli-NYISO, Kathleen Goodman-ISO NE, Theodore G. Pappas-NYSRC; Guy Zito for NPCC CP9 Wkg Group(13)		1	Listed, supporting, group participants of NPCC feel there should be more detail written into the actual Standard as opposed to relying on the Reference Document. One area that we feel that is weak in the Standard is the requirements made of the PSE. As written, the PSE is not specified by name anywhere in the Standard. The SAR references "when an entity desires to transfer energy…" one would assume this to be the PSE and the Reference Document points to 402 in the Standard to cover this requirement, yet 402 references the IA only. The condensed format and transition from 12 sub-items of the SAR to 4 sub-standards/requirements is a good step.
[4] **This standard does not impose any reliability requirements on the PSE. If the PSE does not comply with the reliability requirements of the RAs, BAs, and TSPs then the PSE's Proposed Interchange would be rejected during the IA verification process per requirement 402. The standard is predicated on the basis that RAs (RTOs, control areas, ISOs) BAs and Regions will impost their respective reliability requirements. Thus, "before" the PSE completes a Proposed Interchange the PSE must understand and respect the reliability and commercial rules of all parties it desires to do business.** **This standard does not impose any reliability requirement on the PSE, because if a PSE does not comply with the reliability requirements of the RAs, BAs, and TSP then the PSE's proposed interchange would be rejected during the IA approval process of requirement 402.** **The standard is predicated on the basis that RAs (RTOs, control areas, ISOs), BAs and Regions will impose their respective reliability requirements.** **Thus "before" PSE puts together a proposed interchange, that PSE must know and respect the reliability and commercial rules of all parties it wants to do business with.**			
Robert Schwermann for WECC Int Wkg Grp (26) Shirley Buckmier-BPAT		1	The Standard excludes the Purchasing-Selling Entity's obligations to submit the reliability oriented transaction data as identified on Page 5 of the SAR. The WECC recommends that this step be included to insure the information handoff is completed between the market and reliability processes.
[5] **This standard does not impose any reliability requirements on the PSE. If the PSE does not comply with the reliability requirements of the RAs, BAs, and TSPs then the PSE's Proposed Interchange would be rejected during the IA verification process per requirement 402. The standard is predicated on the basis that RAs (RTOs, control areas, ISOs) BAs and Regions will impost their respective reliability requirements. Thus, "before" the PSE completes a Proposed Interchange the PSE must understand and respect the reliability and commercial rules of all parties it desires**			

<table>
<tr><td colspan="4">to do business.

This standard does not impose any reliability requirement on the PSE, because if a PSE does not comply with the reliability requirements of the RAs, BAs, and TSP then the PSE's proposed interchange would be rejected during the IA approval process of requirement 402.

The standard is predicated on the basis that RAs (RTOs, control areas, ISOs), BAs and Regions will impose their respective reliability requirements.

Thus "before" PSE puts together a proposed interchange, that PSE must know and respect the reliability and commercial rules of all parties it wants to do business with.</td></tr>
<tr><td>Marc Butts for Southern Co Svcs(9)
Roman Carter for Southern Co Generation (10)</td><td></td><td>1</td><td>The SDT has done an admirable job covering the reliability issues associated with a bilateral interchange. However, I would like to make the following comments:
Under Requirement 404 (a), the IA shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange. Under the Coordinate Interchange SAR, it is required "the IA shall communicate implementation status to all parties (with which the Interchange Transaction must be coordinated". Under the Functional Model, the IA Function is responsible for communicating the Interchange Transaction information into the Reliability Assessment Systems (e.g. IDC). One could make a convincing argument that the IDC (for the Eastern Interconnect) is an involved party of the transaction since the Functional Model requires the transaction information be provided to it. Therefore, it is suggested that the Requirement 404 be revised to include communication to the IDC by including it into the Requirement: "The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange, including the Reliability Assessment System".</td></tr>
<tr><td colspan="4">[6] Under the following draft standards are requirements to provide the RA with information needed for reliability:
Determine Facilities Ratings, Operating Limits and Transfer Capability
Operate Within Interconnected Reliability Operating Limits
Coordinate Operations
Requirement 403 states, "The Reliability Authority, Balancing Authority and Transmission Service Provider</td></tr>
</table>

shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange is *acceptable and reliable with respect to the functional responsibilities*" [Italics added] **This standard addresses the review of Interchange prior to implementation. The real-time management of flow on the transmission system is not addressed in the standard. The Standard Drafting Team believes real-time flow management is captured under the Coordinate Operations Standard.** **Under the following draft standards, facility ratings, operate within limits, and coordinate operations, are requirements to provide the RA with information needed for reliability. (Note: GLS to add correct name and designation for the standards) Requirement 403 states, "The Reliability Authority, Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange *is acceptable and reliable with respect to their functional responsibilities."* [Italics added]** **This standard addresses review of interchange prior to implementation and real-time management of flow on the transmission system is not addressed in this Standard. The SDT believe this is captured under the Coordinate Operations Standard.**			
Doug Hils for MISO CA Wkg Group		1	The Standard requirements seem to reflect similar intentions to those presented in the SAR requirements, however the coordination is not clear for day-ahead versus real-time. For example, if the IA confirms Interchange to be implemented for a monthly transaction for example, is it ever verified again prior to the schedule running? Is it verified on a daily basis though nothing changed?
[7] Reliability changes to Confirmed Interchange are addressed under 402.b.vii.1. The fact that the confirmation is two days or two minutes old does not matter. Once an Interchange is confirmed it moves to an Implement Interchange state, unless it changes under 402.b.vii.1. no other verification should be necessary. **Reliability changes to Confirmed Interchange are addressed under 402.b.vii.1. The fact that the confirmation is two days or two minutes old is does not matter. Once an interchange is confirmed it moves to implement, unless it changes under 402.b.vii.1., no other verification should be necessary.**			

Steven Cobb-SRP		1	SRP suggests the CI Standard include clarification of the relationship between the IA and PSE. The role of the PSE in coordinating Interchange is described in the SAR. However, the role of the PSE is not defined in the Standard. The CI Standard needs to explain where the 'proposed' Interchange originates. Standard 404 states The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange. Based on the CI Standard, one would not know who all entities are. The PSE's role in coordinating interchange is defined in the CI Standard Reference Document. However, it is unknown the final form that the CI Reference Document will take. The Compliance section of the Standard itself states that the PSE's data will be utilized to determine the IA's compliance. Based on the Standard, it is unknown where that data comes into play. The information provided by the Functional Model defines the relationship between the PSE and IA. It also defines most of the IA responsibilities included in the CI Standard. The CI Standard should reiterate the PSE-AI relationship.
[8] This standard does not impose any reliability requirements on the PSE. **The entities that a PSE may need to contact for a Proposed Interchange may vary per Interchange. This standard only defines the reliability tasks for carrying out Interchange. The standard does not directly define the PSE or the role of the PSE. For all entities described in the standard refer to the NERC Reliability Functional Model as this standard applies to entities performing various electric system functions as defined in the Function Model.** **See PSE discussion in Summary Consideration.** **The drafting team cannot identify all entities involved in a proposed interchange that the PSE may contact because the number and types of entities may vary per interchange.** **The standard only defines the reliability tasks for carrying out interchange. The Standard does not directly define the PSE or the role of the PSE. For all entities described in the Standard refer to the NERC Reliability Functional Model. See bottom of page 2 of the Standard for a statement on the FM.**			
Mark Creech for TVA (4)	1		The method by which you would achieve these requirements still leaves questions
[9] **This standard will provide the "What" not the "How." The standard is "performance-based" and therefore does not**			

require the use of specific tools, formats or methods to achieve compliance with the standard's requirements. The standard applies to the **what** not the how.			
James Spearman/Florence Belser (7)-PSC of SC	1		The standard only implies that the IA has confirmed the approvals from all involved entities. While this may be a reasonable assumption and is discussed in the related Reference Document, it would have been better to spell out this requirement in the standard.
[10] **The IA must contact all entities. The drafting team believes this requirement is covered under measures 402 and 404.a.1.** See measure 402. The IA must contact all parties, see measure 404.a.1. The team believes the requirement is covered under these two mearures.			
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		A condensed format and transition from 12 sub-items of SAR to 4 sub-standards/requirements is a good step. A few improvements could be made as per subsequent suggestions/comments given below.
[11] **The team appreciates your comments.** The team appreciates your comments.			
Patti Metro for FRCC (15)	1		
William Smith-Allegheny Power	1		
Alan Johnson-Mirant	1		
Al DiCaprio (4)-PJM	1		
Tom Hawley-We Energies	1		
Ron Gunderson-NB PPD	1		
Scott Moore for SPP ORWG (8)	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		

Gerald Rheault-Manitoba Hydro	1		
Joel Mickey-ERCOT	1		
Susan Morris for SERC (1)	1		
John Horakh-MAAC	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Peter Burke-American Trans Co			
Ev Lucenti-Power Decisions			

2. Can you identify any reason why ERCOT's request for an Interconnection-wide Regional Difference should be denied?
Summary Consideration: ERCOT has withdrawn its request for a regional difference under the current draft of the standard because of revisions to the interchange state definitions. **The drafting team addressed DC ties in the standard and revised the Reference Document.** **The standard drafting team will address DC ties and define the requirements for DC ties. DC ties must be coordinated. The Standard deals with interchange.** **With regard to the DC ties see the discussion in the reference document. If you are not entering the DC tie in your ACE equation, but as generation or load, then it must be coordinated between the BA.** **For flows that that cross BAs boundaries is interchange. For DC ties flows that are not in the ACE equations then it is interchange and will be coordinated.** **Injection point or load point that does affect other systems. The interchange information must be coordinated. CI is not just so everyone can balance but how systems will be affected by the interchange.** **If ERCOT carries reserves for the loss of the DC tie (and they do) then this is a facilities loss for ERCOT.** **The RAs must know what is flowing; therefore it must be coordinated. This is Coordinate Operations and should be included in the Coordinate Operations Standard.** **If it is an interchange it must be handled under the CI, if not it must be under the CO Standard. This does not force anyone to have an interchange but if you do then you must follow the CI.** **We need more information on the DC tie operators for SPP – as long as the schedule is coordinated then the responsibility is done on SPP (or the E Interconnection) side then ERCOT could be exempt.** **Energy transfers that cross Balancing Authority boundaries" do not differentiate between AC and DC ties. All interchanges, whether or not included in the ACE equations, need to be coordinated for reliability.** **ERCOT is already doing everything that is required by the standard; their request may be to not keep all the data required.** **Question for Joel to discuss with ERCOT and send to the CISTDDT:** **Is 401 the only requirement that ERCOT needs an exemption? Why is it needed for 402, 403, 404?** **If it is the amount of data that has to be retained, ERCOT should ask for an exemption to the compliance but not the standard.** **Action: The team will discuss DC ties further after Joel's comments are received. GLS will draft responses below and**

when the team hears back from Joel will draft a Summary Consideration.			
Commenter(s)	**Yes**	**No**	**Comments**
Ed Davis-Entergy	1		ERCOT may have a regional exemption except for interchange transactions scheduled to through the DC Ties to entities outside of ERCOT. Interchange transaction schedules to entities outside ERCOT should conform to these NERC standards.
[12] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			
Ron Gunderson-NB PPD	1		ERCOT may still have interchange (as outlined in the definitions with the other interconnections. For interchange that crosses the interconnection boundary, ERCOT must follow this standard or it would have a significant adverse impact on the reliability of the other interconnections.
[13] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		We agree with the ISO/RTO Standards Review Committee consensus as stated below: "Recognizing that ERCOT follows the generally accepted practice of modeling DC tie lines as a generator or load, outside the ACE equation, transfers over DC ties lines should still be coordinated in a deliberate and orderly manner. The definition of interchange, "Energy transfers that cross Balancing Authority boundaries" does not differentiate between AC and DC ties. All interchanges, whether or not included in the ACE equations, need to be coordinated for reliability."
[14] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			

Kathleen Goodman-ISO NE, Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)	1		ISO-NE (NYSRC) understands that ERCOT does not operate any synchronous ties with either the Eastern or Western Interconnections, however we are concerned how transfers over DC ties will be coordinated even when they are modeled as a generator or load and not in the ACE equation. Effectively this is still inter-Area interchange that needs to be reliably coordinated. If not the Coordinate Interchange Standard, what Standard will assure this? The definition of interchange is "Energy transfers that cross Balancing Authority boundaries" which does not differentiate between AC and DC ties. It would seem that this Regional Difference request is not appropriate, and all DC inter-Area ties should fall under this Standard regardless of how an Area models them.
[15] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			
Lloyd Linke for MAPP RRC and OC (9)	1		Perhaps not denied, but clarified/modified. ERCOT may still have interchange (as outlined in the definitions) with the other interconnections. For interchange that crosses the interconnection boundary, ERCOT must follow this standard or it would have a significant adverse impact on the reliability of the other interconnections.
[16] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			
Doug Hils for MISO CA Wkg Group	1		Yes, Interchange as it relates to DC tie operation should be included in this Standard. Internal transfers may be exempt.
[17] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			
Ev Lucenti-Power Decisions	1		
Gregory Campoli-NYISO	1		
Tom Hawley-We Energies		1	ERCOT Operations appear to meet all requirements for the interconnection-wide regional difference.
[18] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			
Alan Johnson-Mirant		1	I have no information to suggest that ERCOT's request for a Regional Difference is in violation of any of the stated criteria for denying their request.

[19] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard.**			
Bert Gumm-Idaho Pwr		1	Regional differences should be allowed.
[20] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard.**			
Ed Riley-CA ISO, CA ISO		1	What about interchange on the DC ties to the Eastern Interconnection? I believe that these are transfers across Balancing Authority boundaries.
[21] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			
Gerald Rheault-Manitoba Hydro		1	Because ERCOT operates asynchronous to both the eastern and western interconnections, they will not have a significant adverse impact on reliability or commerce in other interconnections, therefore their Regional Difference should not be denied.
[22] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard.**			
James Spearman/Florence Belser (7)-PSC of SC		1	PSCSC response assumes the DC ties are handled consistent with provisions in the Coordinate Interchange Standard Reference Document.
[23] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**			
Joel Mickey-ERCOT		1	ERCOT's DC Tie transactions are not part of the ACE equation. **ERCOT has withdrawn its request for a regional difference under the current draft of the standard. The drafting team has added to the discussion of DC ties in the CI Reference Document.**
John Horakh-MAAC		1	Assuming that the ERCOT Region will be a single Balancing Authority, then there is no Interchange <u>within</u> ERCOT, so this Standard does not apply within ERCOT. By definition, Interchange is energy transfers that <u>cross</u> Balancing Authority boundaries.
[24] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard.**			
Mark Creech for TVA (4)		1	TVA supports the request for regional difference based on the above statements provided.
[25] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard.**			

Patti Metro for FRCC (15)		1	Comments should actually be required if the yes box is checked to better understand why an entity does not think ERCOT qualifies for a regional difference. With the fact that ERCOT operates asynchronous to the Eastern and Western Interconnections, ERCOT has no adverse impact on the reliable operations of the other interconnections the regional difference should be approved.
[26] **ERCOT has withdrawn its request for a regional difference under the current draft of the standard.**			
Robert Schwermann for WECC Int Wkg Grp (26)		1	NERC and FERC Policies allow for regional differences.
[27] **In drafting this standard the drafting team follows the NERC Reliability Standards Reference Manual. The manual defines the process for requesting a regional difference. A region does not need to request a regional difference for a "How" as this standard address the "What."** **From the Standards Reference Manual:** ***Criteria for Regional Standards and Regional Differences*** Proposals for Regional Standards or Regional Differences that are intended to apply on an **Interconnection-wide basis** shall be presumed to be valid and included in a NERC Reliability Standard unless there is a clear demonstration within the NERC standards process that the proposed Regional Standard or Regional Difference: • Was not developed in a fair and open process that provided an opportunity for all interested parties to participate; • Would have a significant adverse impact on reliability or commerce in other Interconnections; • Fails to provide a level of reliability of the bulk electric system within the Interconnection such that the Regional Standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security; or • Would create a serious and substantial burden on competitive markets within the Interconnection that is not necessary for reliability. The standard does not preclude regional differences. The WECC does not need to document more but different from the standard is the problem. The standard is a what not a how. (This is defined in the process manual and GLS will add to the response).			
Shirley Buckmier-BPAT		1	Both NERC and FERC Policies allow for regional difference.
[28] **In drafting this standard the drafting team follows the NERC Reliability Standards Reference Manual. The manual defines the process for requesting a regional difference.**			
Steven Cobb-SRP		1	We believe the form meant to request reasons for checking "Yes."

[29] **The drafting team apologizes for the confusion with the form.**			
William Smith-Allegheny Power		1	
Ken Githens-Allegheny Energy		1	
Al DiCaprio (4)-PJM		1	
Raj Rana-AEP		1	
Richard Kafka-Pepco		1	
Scott Moore for SPP ORWG (8)		1	
Susan Morris for SERC (1)		1	
Karl Tammer for RTO/ISO Council (9)			
Marc Butts for Southern Co Svcs(9)			
Peter Burke-American Trans Co			
Roman Carter for Southern Co Generation (10)			

3. Are you aware of any other Regional differences that should be included in this standard?			
Summary Consideration: A region does not need to request a regional difference for a "How" as this standard address the "What." **From the Standards Reference Manual:** ***Criteria for Regional Standards and Regional Differences*** Proposals for Regional Standards or Regional Differences that are intended to apply on an **Interconnection-wide basis** shall be presumed to be valid and included in a NERC Reliability Standard unless there is a clear demonstration within the NERC standards process that the proposed Regional Standard or Regional Difference: • Was not developed in a fair and open process that provided an opportunity for all interested parties to participate; • Would have a significant adverse impact on reliability or commerce in other Interconnections; • Fails to provide a level of reliability of the bulk electric system within the Interconnection such that the Regional Standard would be likely to cause a serious and substantial threat to public health, safety, welfare, or national security; or • Would create a serious and substantial burden on competitive markets within the Interconnection that is not necessary for reliability. Proposals for Regional Standards or Regional Differences that are intended to apply only to **part of an Interconnection** will be included in a NERC Reliability Standard only if the proponent demonstrates that the proposed Regional Standard or Regional Difference: • Was developed in a fair and open process that provided an opportunity for all interested parties to participate; • Would not have an adverse impact on commerce that is not necessary for reliability; • Provides a level of bulk electric system reliability that is adequate to protect public health, safety, welfare, and national security and would not have a significant adverse impact on reliability; and • Is based on a justifiable difference between Regions or between subregions within the Regional Council's geographic area. **This Standard is focused in its scope and is not intended to be a replacement for Policy 3. The requirements associated with this standard are intended to address reliability issues; therefore, the standard does not address issues associated with timing, format, or tools.**			
Commenter(s)	**Yes**	**No**	**Comments**
Ed Riley-CA ISO, CA ISO			I believe that this standard is short on detail that is considered essential to the day-to-day

			operation in the Western Interconnection. If that detail is not in the next version, I would expect that WECC will identify some regional differences.
[30] **This Standard is focused in its scope and is not intended to be a replacement for Policy 3.**			
Bert Gumm-Idaho Pwr	1		Currently, the WECC Reliability Management System (RMS) provides for monitoring of reliability issues and sanctions for non-compliance. This standard does not provide the same level of detail as RMS, therefore, Regional differences may arise as some Regions adopt less stringent rules than WECC. If NERC adopts a standard that is less stringent than the WECC, the WECC should be allowed to maintain its' more restrictive measures.
[31] **This Standard is focused in its scope and is not intended to be a replacement for Policy 3.**			
Robert Schwermann for WECC Int Wkg Grp (26)	1		The CI standard lacks significant detail that will be required for implementation and day-to-day operation. WECC reserves the right to make their standards more stringent than NERC standards as applicable. It is assumed that individual regions must develop supplemental business practices. WECC, through the RMS Standards Phase 3, has E-Tagging standards. These adopted standards provide sanctions with the current E-Tag product as supported in NERC policy 3. If the NERC CI standard eliminates Policy 3 in its present form, WECC may propose to continue its standard, develop a new standard, or ask for a regional difference.
[32] **This Standard is focused in its scope and is not intended to be a replacement for Policy 3.**			
Shirley Buckmier-BPAT Steven Cobb-SRP	1		The CI standard lacks significant detail that will be required for implementation and day-to-day operation. As part of WECC we have regional standards that we are required to met, such as WECC RMS Standards Phase 3, which has E-Tagging standards. These adopted standards provide sanctions with the current E-Tag product as supported in NERC policy 3. If the NERC CI standard eliminates Policy 3 in its present form, WECC may propose to continue its standard, develop a new standard or ask for a regional difference. The WECC's current Reliability Management System program establishes measures and sanctions for non-compliance to standards. SRP believes that the WECC will continue to develop and enhance its Reliability Management System own compliance program.
[33] **This Standard is focused in its scope and is not intended to be a replacement for Policy 3.**			
Karl Tammer for RTO/ISO Council (9)		1	The IRC recognizes that Regions can and do make more stringent requirements.
[34] **The drafting has noted your comment.**			

Marc Butts for Southern Co Svcs(9); Roman Carter for Southern Co Generation (10)		1	We do not currently know of any Regional differences at this time. However, during the initial phasing in of standards, each region may find adopting or developing a different approach provides increased reliability. Therefore, we believe that differences should be considered as they are identified in the future.
[35] **The drafting has noted your comment.**			
Mark Creech for TVA (4)		1	The industry should reserve the right to review any request for regional differences on a case-by-case bases.
[36] **The drafting has noted your comment.**			
Theodore G. Pappas-NYSRC		1	The NYSRC Reliability Rules are not inconsistent with or less stringent than the proposed NERC Standard, and the NYSRC has elected not to propose that NYSRC Reliability Rules be made part of this Reliability Standard.
William Smith-Allegheny Power		1	
Ed Davis-Entergy		1	
Alan Johnson-Mirant		1	
Al DiCaprio (4)-PJM		1	
Ev Lucenti-Power Decisions		1	
Gerald Rheault-Manitoba Hydro		1	
Gregory Campoli-NYISO		1	
James Spearman/Florence Belser (7)-PSC of SC		1	
Joel Mickey-ERCOT		1	
John Horakh-MAAC		1	
Kathleen Goodman-ISO NE		1	
Ken Githens-Allegheny Energy		1	

Lloyd Linke for MAPP RRC and OC (9)		1	
Doug Hils for MISO CA Wkg Group		1	
Patti Metro for FRCC (15)		1	
Pete Henderson / Khaqan Khan-The IMO-The IMO		1	
Peter Burke-American Trans Co		1	
Raj Rana-AEP		1	
Richard Kafka-Pepco		1	
Ron Gunderson-NB PPD		1	
Scott Moore for SPP ORWG (8)		1	
Susan Morris for SERC (1)		1	
Tom Hawley-We Energies		1	
Guy Zito for NPCC CP9 Wkg Group(13)		1	

4. Do you agree with the "sanction" philosophy in this standard of using percentages rather than absolute counts to determine levels of compliance

Summary Consideration:

The comments justify using percentages. Individual measures will be addressed in the specific measures. The team agrees that the percentages should be tightened but by what degree or have many level the group request the industry provide that data. Change the % from greater than 0 to 1%, and greater than 1% to 2 etc and add a number of occurrences and MW and could change the reset time to e.g., one month, or change the sanctions to be more stringent for smaller offences.

What do we expect for level of performance for each function?

A percentage and a number.

The number needs to be a % because of the responses we received from the industry. The team has decided that we need to go with a % that needs to be less. Provide a discussion on putting a % and number (so you will not penalize the smaller entity) e.g. less than 1% or greater than 10. (Mike Oatts will work on the % and number for 401, 402, 403, and 404). The question is not necessarily about the volume but if you put the number in the right hour.

Use 1% not to exceed X number e.g. 3 instances is an option. What would be the best time frame and frequency for this type of arrangement? Is there a level of MW value that should be added? Is it really the number that is missed that is important, the number of MW per schedule, or the impact? Is the real issue that you missed an Interchange and that counts as 1 hour and you add up the hours that something is missed?

We are talking about the IA and BA, do we need a separate requirement for each? What constitutes an error? Is it the order of magnitude? The measurement cannot set an entity up to fail.

In 401 we are measuring against what the IA sent and what the BA implemented. Measure what the IA gave the BA and what the BA entered into the setter. If the BA hears from ten IAs and he adds those together and enters a net interchange; then, is that an error for each schedule for 1 hour?

Is the hourly entry into the ACE equation against what was received from the IAs is what should be measured?

If you have an error in your scheduling system and there is an error, then you penalize by hour if there is a net schedule. If individual IA Interchange schedules are entered into the schedule setter (EMS) then the BA could be penalized by interchange but this will not work for a net interchange number.

What is the record and what is the evidence. If you have to check with each IA for each interchange then the penality should be for each Interchange submitted to the BA by the IA.

For Version 0 – the BAs will probably perform a portion of the IA function, and will essentially perform the same function as the CAs now.

The impact for the hour is what is implemented for the hour. If he guesses or if he makes two mistakes and the errors balance, the ACE is still correct. The number entered into the ACE equation for the hour should be what you are judged. The compliance occurrence effect would be the number in the ACE entry (net number). The violation is on the net value, Implemented Interchange value, and the operator should have some time to (perhaps 10 minutes) correct an error. What would be considered a "correctable error?" There are mistakes and there are correctable errors that are corrected. Mistakes should be penalized, but not errors that were corrected.

Once the ramp starts, if the number is in wrong or the number is not entered for the correct ramp, which should be counted as an error. If a number is put in wrong, how will that be reported? What physical evidence will be available for measurement?

We do care if a schedule drives frequency high or low because of an Interchange number entry is in error then we should be concerned. If you have an error in the opposite direction, compensating direction, which helps the system, should a BA be penalized? Every error is bad, but when should NERC get involved. Have spot checks that are called for a complaint. The complaint should be based on evidence.

What constitutes an error is easy to define but at what point does it become punishable? The measure must be reasonable and practical. This standard is for implementing what you are told. What is the record that will need to be kept? The error occurs when you enter the Interchange into ACE. Should we provide the compliance investigation team leeway and flexibility when they investigate? What historical data that the BA is required to keep could determine how much leeway the team could have.

What constitutes a non-compliance event?

- If the net scheduled interchange is off from the number submitted to the BA from the IA(s), for 60 minutes, without action to correct by the operator. For 60 minutes or the duration of the schedule, which ever is shorter.
- What if you declare an emergency, e.g., you computer system is down, or you have to go to the backup center? There should be flexibility by the investigation team to look at duration, magnitude, and impact on the system
- If the net scheduled interchange in the EMS is different than the calculated interchange, at any time, from the start of the ramp until the interchange is ramped out.
- How do we measure for dynamic schedules?

Commenter(s)	Yes	No	Comments
Al DiCaprio (4)-PJM			All schedules must be properly implemented. Allowing any number or % can be a potential serious problem. As a Reliability Standard the goal is 100%. The fact that errors may occur points to the issue of sanctions. The standard should relegate sanctions to the Regions or the RTOs to deal with and not tie them to some arbitrary number or %.
[36] The team agrees with the commenter that the standard does not permit any non-compliance. The levels of non-compliance are established to assess degrees of an entity not adhering to the standard. The drafting team will forward the comment on relegating sanctions to the Regions or to the RTO to NERC Compliance. There is a credibility problem if the team allows for non-compliance. With percentages, the team is saying that some level of non-compliance is acceptable, even with the increase in the penalties. The dt agrees that the levels should be revised. The first measure should be up to 100%. The dt does not know what to change the percentages to. The dt could change the level 1 to something less than 100% and ask should be the percentages for each level, and how many levels should there be?			
Alan Johnson-Mirant		1	I agree in part with the sanction philosophy, but I think that an additional level of gradation needs to be added. It strikes me that an entity that achieves 90% compliance on 1000 records has a greater negative impact on reliability than the entity that achieves 90% compliance on 10 records. As such the entity with the greater negative impact on reliability should be more severely sanctioned than the entity whose non-compliance results in less of an impact on reliability. I don't know where the breakpoints should be, but I believe consideration should be given to creating a few buckets (for example 0-100, 101 – 500, >500) and utilizing the four sanction levels within each bucket.
[37] The team debated this issue several times. The problem with percentages versus numbers can result in the same arguments. If the 1000 records were all 1 MW transactions and the 10 records were all 1000 MW transactions the impact may be reversed of what one would logically think.			
Patti Metro for FRCC (15)		1	Should be both records matching and reliability impact. For instance MWH needs to be addressed. Overall thought on compliance for this standard: Any transaction that is large enough can be detrimental to the interconnection if it is not coordinated properly between entities.
[38] Any transaction can have a detrimental impact on reliability. The concept of which indicator (percentage, number, or MHR) will again be reviewed by the drafting team.			

Peter Burke-American Trans Co		1	Could the SDT provide some additional insight in determining this way of measuring non-compliance? In trying to treat small and large companies equitably in terms of non-compliance does it satisfy the larger purpose in requiring a reliable interconnection? In the example given above, the small company and large company were being treated equitably in terms of the non-compliance but the larger entity may have been able to use the system in their favor more than, and possibility to the disadvantage of, the smaller entity.
[39]] Any transaction can have a detrimental impact on reliability. The concept of which indicator (percentage, number, or MHR) will again be reviewed by the drafting team. The problem with percentages versus numbers can result in the same arguments. If the 1000 records were all 1 MW transactions and the 10 records were all 1000 MW transactions the impact may be reversed of what one would logically think.			
Richard Kafka-Pepco		1	In concept, a percentage may be more equitable to large and small participants, but that begs the issue. The proposed percentage bands are far too large. As a practical matter, interchanges must match and the goal is 100%.
[40] The drafting team will consider the band widths for non-compliance again.			
Gerald Rheault-Manitoba Hydro		1	
Ed Riley-CA ISO, CA ISO	1		I agree that the percentage sanction philosophy is appropriate. I believe that the performance levels should be adjusted such that there is a tighter measure of non-compliance.
[41] The drafting team will consider the band widths for non-compliance again.			
Gregory Campoli-NYISO, Karl Tammer for RTO/ISO Council (9)	1		To encourage a high level of compliance, the ranges for the levels of non-compliance could be made tighter than what is proposed. The NYISO recognizes that regional differences and tariff applications have implications in applying sanctions. Thus specific sanctions are best developed regionally.
[42]			
Doug Hils for MISO CA Wkg Group	1		We agree with percentages however what constitutes what a record is.. not only are records not defined but percentages levels of implemented Interchange not matching up is unacceptably high. Huge volumes of implemented interchange not matching up could still be compliant to this Standard. We also question if the burden of record keeping across the industry has been considered in demonstrating compliance.
[43]			

Scott Moore for SPP ORWG (8)	1		The purpose of the standards is to ensure compliance. That being the case, the tolerances for noncompliance should be fairly tight. The ranges for the different levels of noncompliance in the proposed standard may be too large. For example, Level 1 should be higher, perhaps 98-99.999%, instead of the proposed 90-99%.
[44]			
James Spearman/Florence Belser (7)-PSC of SC	1		It must be recognized that ***any*** problem may result in reduced reliability whether originating from a small or large entity. The approach adopted by the SDT appears to be compliance-based rather than performance-based. Is the objective good data or a reliable system? The PSCSC maintains that the real objective is reliability, and not complete transaction records. They are merely an indicator that the process mechanics are working.
[45]			
Robert Schwermann for WECC Int Wkg Grp (26)	1		Yes, without sanctions enforcement would be useless. With Percentage methodology this standard is more equitable and reasonable. WECC RMS uses percentage basis as well.
[46]			
Bert Gumm-Idaho Pwr	1		There cannot be enforcement without sanctions and the sanctions must be levied fairly.
[47]			
Theodore G. Pappas-NYSRC Kathleen Goodman-ISO NE Guy Zito for NPCC CP9 Wkg Group(13)	1		In this way, it would be considered as a more fair process. Please also see our statement in Comment Form Question #23 response regarding our continued opposition to monetary sanctions. *(The NYSRC is opposed to monetary sanctions as the only option for dealing with noncompliance as applied in this and other proposed NERC Standards. Unfortunately, direct monetary sanctions invite "gaming the system", and encourage "business" decisions based on potential profits or savings versus potential penalties. Instead of monetary sanctions, the NYSRC prefers that NERC have the authority to issue letters of increasing degrees of severity to communicate noncompliance of mandatory standards. The NYSRC and NPCC now rely on a more stringent and mandatory process than monetary sanctions to assure compliance with reliability standards. Compliance is now mandatory through the contractual agreements and tariffs that all participants need in order to conduct business. The use by the NYSRC and NPCC of letters to regulatory agencies and other oversight bodies for reporting noncompliance has demonstrated that letter sanctions are a more effective tool for ensuring adherence to standards. Such letters establish the basis for liability in the event of a subsequent criterion violation, and in the case of market participant noncompliance, threaten the violator's ability to do business with or through an ISO or RTO. Moreover, letters that communicate noncompliance best allow focus on the "root cause" of a violation, as well as its reliability*

			impact. Therefore, the NYSRC recommends that this and other NERC Standards expressly provide that letter sanctions be used in addition to or instead of monetary sanctions under circumstances in which they would be an equally or more effective enforcement mechanism.)
[48]			
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		In this way, it would be considered as a more fair process
Ed Davis-Entergy	1		
Raj Rana-AEP	1		
Tom Hawley-We Energies	1		
Roman Carter for Southern Co Generation (10)	1		
Ron Gunderson-NB PPD	1		
Shirley Buckmier-BPAT	1		
Steven Cobb-SRP	1		
Susan Morris for SERC (1)	1		
William Smith-Allegheny Power	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Marc Butts for Southern Co Svcs(9)	1		
Mark Creech for TVA (4)	1		
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		

Ev Lucenti-Power Decisions	1		

5. This standard does not dictate a specific deadline for . . . Do you agree with this approach?
Summary Consideration: Responses to the comments will be drafted after the DT discusses the IA Function and timing. **Timing is not a reliability requirement so long as all approvals are obtained with enough time to implement but should be addressed in tariffs.** **If entities like the timing in the NAESB guidelines (see CI BP TF posting) they can adopt them. This is not a reliability concern.** **Currently we have E-Tag timing requirements for the interconnections. These requirements will continue to be enforced. We do not see a need for them to be in this standard.** **If timing requirements are set then the timing will be used as a maximum and others will use as a minimum. The market will be stopped according to the timing requirements. We need to have words added to the standard to have some kind of backstop. The backstop should be in NAESB standards but it looks like something is needed in this standard because the industry says so in their comments below.** **May need NAESB and NERC items in one document (users manual) to show the industry that everything is covered. This may help cut down on the confusion.** **We should respect that timing requirements are being developed by the market.** **Lack to timing requirements could bring on chaos in the industry for deal making. If there are no timing requirements then the market may not be able to make alternate deals.** **NERC will need to recognize the NAESB business practice standards that are agreed to by the industry.** **NERC policy says now that the timing is a recommended timing.** **Are there some necessary timing that are needed for reliability approvals. This may need to be in Coordinate Operations. Does not timing come into your ability to perform the reliability functions of an interchange?** **Why do we need a number for timing for reliability? Timing will be determined by the market required timing.**

The PSE will not be confused of the market requirements, they will understand the markets they are dealing with. **We protect the reliability side (operator) by saying that the reliability side may say no at any time.** **The reliability issue is that you agree on the interchange and you implement it at the same time.** **Add to the Reference Document or develop a users guide (industry will go forward with the timing as is now – and the discussion used in the NAESB bp posting) to the Reference Document. NAESB has adopted the E-Tag timing and this timing (currently being used in the industry) provides the timing for the industry to use. This timing provides a backstop for the reliability assessment to take place.** **All the timing requirements are commercial business practices and are expected to be developed by NAESB.** **Recongized that NAESB is developing requirements for bp and NERC reliability requirements and it is expected that all FM functions will follow these standards.** **Summary Consideration: Adding arbitrary timing requirements into the Standard will not guarantee that better or faster reliability activities will take place. The current proposed NAESB business practices provide necessary timing requirements which also permit sufficient reliability process to take place and therefore can be used for both market and reliability purposes.**

Commenter(s)	Yes	No	Comments
William Smith-Allegheny Power		1	Timing guidelines are essential to real time operations. The current guidelines have been developed over time and with industry input.
[49]			
Marc Butts for Southern Co Svcs(9); Susan Morris for SERC (1) Ed Davis-Entergy		1	Parties involved in the Interchange should be required to conform to timing requirements contained in industry-wide existing business practices, which today is E-TAG.
[50]			

Mark Creech for TVA (4)		1	The current timing guidelines provide for a fair and equitable structured process, which allows for reliable operations to all parties while accommodating for real time operations.
[51]			
Alan Johnson-Mirant		1	I agree that the timing of data exchange is primarily a business issue and is outside the scope of this standard. However, I believe that minimum/default time limits should be specified in the companion business standard being developed by NAESB. Therefore, I think consideration should be given to officially linking the two standards by referencing the NAESB companion standard in both the paragraphs describing the Effective Period and Clarifying documents. This standard should not take effect until the NAESB companion standard is ready.
[52]			
Ed Riley-CA ISO, CA ISO	1		We agree that the standard does not need to set specific timing, however it should not be construed to preclude individual entities, regions, or interconnections from setting specific timing requirements for their transactions to match their tariffs or for reliability reasons.
[53]			
Doug Hils for MISO CA Wkg Group		1	While the Standard does not have to dictate a specific deadline, it does have to dictate that specific deadlines be agreed to that will allow for the reliability assessment. The language should recognize that those performing the Reliability Functions have the authority to set the timing requirements necessary for the purpose of assessment of transmission service, ramping capability, etc. and also accommodate the timing for implementing the interchange once that transaction has moved to the “Implement” state. The technical discussion document seems to recognize this fact, however it is not reflected in the standard.
Bert Gumm-Idaho Pwr		1	This cannot be left up to individual parties. Timing requirements have been very important during the past few years in maintaining a reliably operated system. The system Operators ability to coordinate interchange relies on their ability to sum schedules after the schedule submission timing requirement closes and match net schedules with Control Areas to ensure a balance on the network.
[54]			

Roman Carter for Southern Co Generation (10)		1	By waiting until the last 5 minutes prior to ramping, for example, to approve a transaction that was requested yesterday is unacceptable to Business. There needs to be adequate time (as provided for in the current Policy 3) for alternative plans on the Business side if the transaction is not actively approved for implementation. Furthermore, is NERC By waiting until the last 5 minutes prior to ramping, for example, to approve a transaction that was requested yesterday is unacceptable to Business. There needs to be adequate time (as provided for in the current Policy 3) for alternative plans on the Business side if the transaction is not actively approved for implementation. Furthermore, is NERC willing to accept a Business Practice Standard enforced by FERC which provides a minimal (less than what current Policy 3 now provides) timeframe to assess reliability. It would be in NERC's best interest to prescribe certain submission and approval timing requirements as a backstop for these transactions. The most practical place is in the Coordinate Interchange Standard.
[55]			
Ev Lucenti-Power Decisions		1	Verification and agreement to Implement a schedule between sending and receiving parties must be done in the hour before the schedule change takes place. Reason: The problem today is that once transactions are approved, the schedules get implemented without final agreement between the receiving and sending parties. When the system is in a precarious loading situation, schedules are taking place that aggravate the loading or in some cases one of the parties (sending or receiving) implements the schedule while the other party does not due to problems within their system. These schedules would not take place if verbal agreement has to be reached prior to implementation.
[56]			
Shirley Buckmier-BPAT; Robert Schwermann for WECC Int Wkg Grp (26)		1	As stated in #3 above, the Standard lacks operational detail in many areas. Timing issues are but one of those issues. BPAT (WECC Wkg Grp) feels that coordinated timelines are an essential part of the process and need to be coordinated with our interconnections.
[57]			
Steven Cobb-SRP		1	As stated in #3 above, the Standard lacks operational detail in many areas. Timing issues are but one of those issues. **Arranging/Confirming/Implementing Timelines:** The merchant and reliability functions will constantly be at odds over the timing of the submittal and approval of Interchange information. We believe standard timelines will benefit reliability by ensuring there is an adequate and consistent time period for trading, arranging, confirming, and implementing transactions. Regional variations can be provided as required. NAESB could also be responsible for establishing these set timelines. Regardless, of who takes responsibility, the timelines must be

			established. **Ramping Timelines:** SRP believes a standardized hourly ramp schedule concept should be identified in the CI Standard. This approach is a benefit to reliability and to the energy markets. Regional variations can be developed as required. As with the scheduling timelines previously mentioned, NAESB could also be responsible for establishing the ramp timelines. A standard hourly window for interchange ramping results in predictable transients on the transmission system followed by primarily static system conditions for most of the hour. The interconnection is permitted to "settle" after the ramp is complete and establish a baseline condition. The predictability of the ramp facilitates more efficient monitoring of system conditions and permits effective corrective action to be taken. This does not mean that ramps outside the Standard window should be prohibited. These ramps are currently permitted, but constitute a small percentage of Interchange. Therefore, they have limited impact to the condition of the system.
[58]			
Patti Metro for FRCC (15)		1	There should be some guidelines provided in this area. We do agree that the timing issue is more of a business practice issue rather than a reliability issue, but NERC needs to implement at least a 10-minute minimum to allow for sufficient time for an entity to complete analysis to ensure reliability. In addition, NERC should work with NAESB in the development of practical timing requirements based on the business issues associated with this. The reliability aspects that may arise should be reviewed by the industry as NAESB follows the process developed. In addition, the example provided on pg 5 of the reference document discusses conditional approval, which implies that there are separate agreements for each entity involved in the interchange. These types of agreements can be confusing if there is no consistency.
[59]			
Ron Gunderson-NB PPD		1	This standard must be coordinated with the business practices to be sure they are implemented so there is no adverse impact on reliability. For example, if the business practices have timing requirements that are too tight, it may not be able to implement all interchange if the information due to the tight timeframe. It may be necessary to promote reliability to set minimum timing requirements for BA's to implement interchange once it has been confirmed.
[60]			
Peter Burke-American Trans Co		1	With timing being decided by the entities this could lead to a very confusing and complex system. In the attached reference document, the IA may get a conditional approval from an RA but the IA also needs to check with the TSP and BA. If either of those entities delays a decision the IA may lose the approval from the RA. Lastly, the IA may be dealing with multiple RA's,

			BA's and TSPs that could each have different and possibly conflicting time schedules.
Raj Rana-AEP		1	This standard must provide guidelines to the parties involved in interchange for specific timing for requesting, approving or implementing interchange schedules from the reliability standpoint. As proposed, this standard requires PSEs to submit interchange schedules tag directly to IAs only, The IA, in turn, processes this information and sends the tag information to other entities involved in the schedule. This serial notification process will add time to the approval process. As a PSE, we would prefer that minimum notification time of 20 minutes be maintained and not increased. We suggest that IA be kept in the loop, however, same as today, when a tag is submitted by the a PSE, this information must go out to all involved entities in parallel. This will minimize the notification time.
[61]			
John Horakh-MAAC	1		This adheres to the concept that Reliability Standards should cover the "what", not the "how".
Kathleen Goodman-ISO NE; Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)	1		ISO-NE (NYSRC) doesn't believe setting standard timing is a practical expectation. This could have Market implications and potentially restrict flexibility for two adjacent Markets to agree to a more conducive timing schedule.
Ken Githens-Allegheny Energy	1		However, AE does have some concerns that timing differences could result in some seams issues between organizations.
Gregory Campoli-NYISO; Karl Tammer for RTO/ISO Council (9)	1		Specific timing requirements should be set regionally.
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		We feel that the timing flexibility should rest with the parties involved with a common agreement.

Tom Hawley-We Energies	1		It is appropriate that parties involved in the Interchange dictate these deadlines.
Lloyd Linke for MAPP RRC and OC (9)			The MAPP Regional Reliability Council has no comment on this aspect of the Standard.
Richard Kafka-Pepco	1		
Scott Moore for SPP ORWG (8)	1		
James Spearman/Florence Belser (7)-PSC of SC	1		
Joel Mickey-ERCOT	1		
Gerald Rheault-Manitoba Hydro	1		

6. Suggested changes to definitions: Interchange: Energy transfers that cross Balancing Authority boundaries **The drafting team agreed to the following definitions at the March 9-10 meeting. The DT should discuss and finalize all definitions.** **Implemented Interchange: The state where the Balancing Authority enters the Confirmed Interchange into its area control error equation's net scheduled interchange component.** **Arranged Interchange: The state where required interchange information is provided to the Interchange Authority.** **Confirmed Interchange: The state where the Interchange Authority has verified the Arranged Interchange and is provided to the Balancing Authorities.** **The team believes that Interchange could be either actual or scheduled.** **The team believes that entities would use adjectives when necessary in describing interchange.** **The team agreed to changed the definition of Implemented Interchange to include net scheduled interchange component:** Implemented Interchange: The state where the Balancing Authority enters the Confirmed Interchange into its area control error equation *net scheduled interchange component*.
Summary Consideration:

Commenter(s)	Comments
Shirley Buckmier-BPAT	We are assuming that the CI standard is only referring to "Scheduled" and not "Actual" interchange as these two components are separated in our ACE. Scheduled interchange can be arranged, confirmed and implemented, however Actual interchange cannot be directly coordinated in a parallel electric system by virtue of provisions in a standard. I**f we are referring only to scheduled interchange then we offer the following definitions:** Interchange: A planned energy transfer between a source BA and a sink BA

[62]	
Steven Cobb-SRP	It is **unclear whether all four proposed definitions above are referring to the total planned Interchange between two BAs or individual Interchange Transactions (or Interchange Schedules).** Interchange: The NERC term "Interchange" in this standard would seem to include "Actual" and "Scheduled" Interchange. These Interchange values are separated into two components in the ACE equation. One would assume that the CI Standard is dealing with the Scheduled Interchange* component because it can be arranged, confirmed, and implemented. Actual Interchange cannot be directly coordinated in a parallel electric system by virtue of the provisions in this proposed Standard. We suggest that "Interchange" and its definition be kept. We also suggest the NERC term "Interchange Transaction" be redefined and used as follows: An individual planned INTERCHANGE transfer between a SOURCE BALANCING AUTHORITY and a SINK BALANCING AUTHORITY. This term would be consistent with the way "Interchange" is used in the "Purpose" section point #(1) of the CI Standard. * Note that SRP considers ALL Dynamic Transfers to be "Scheduled Interchange" because they are coordinated and controlled between Balancing Authorities regardless of what side of the ACE equation they affect. With the exception of "Interchange," the definitions in the CI Standard refer to conditions ("states"), not names for discrete values. This causes a problem in the Standard's text when it refers to "Arranged, Confirmed, or Implemented Interchange." Example: 401.b.1 "The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority. Two "States" or conditions can't "match." However, two defined values can.
[63]	
Alan Johnson-Mirant	Okay with the definition, but believe that the term should be "Interchange Transaction" to be consistent with version 2 of the NERC functional model and the Operations Manual.
[64]	
Robert Schwermann for WECC Int Wkg Grp (26)	A planned energy transfer between a source BA and a sink BA
[65]	
Bert Gumm-Idaho Pwr	Recommend Addition of Definition for Actual Interchange
[66]	
Ed Riley-CA ISO, CA ISO	An energy transfer between a source BA and a sink BA that may cross other BA boundaries.
[67]	

Ev Lucenti-Power Decisions	ADD – Confirmed Schedule Change – Schedule changes to be confirmed between sending and receiving parties within 1 hour of the schedule change.
[68]	
John Horakh-MAAC	Add “Bilateral” before “Energy” (E becomes e). Add definition for “Bilateral: Between a source and a sink, occurring at the same time in equal and opposite directions”.

6. Suggested changes to definitions: Arranged Interchange: The state where all arrangements necessary to submit the interchange request to the Interchange Authority have been made.

Summary Consideration: The team agreed to change the definition to:

***The state where required interchange information is provided to the Interchange Authority*.**

Commenter(s)	Comments
Marc Butts for Southern Co Svcs(9) Roman Carter for Southern Co Generation (10)	The definition for Arranged Interchange leaves a void in the transaction process. It merely states that all Business Arrangements have been made. What about the state where the IA actually receives the request for interchange? It is not covered in any of the definitions below. In Figure 1 of Appendix B, it clearly shows the IA receives the data while still in the Arranged Interchange State. Therefore, it is suggested that the definition be modified to read as follows: ***The state where completed and required information from the necessary Business Arrangements is provided to and received by the Interchange Authority***.
Shirley Buckmier-BPAT, Steven Cobb-SRP, Robert Schwermann for WECC Int Wkg Grp (26)	We are assuming that the CI standard is only referring to "Scheduled" and not "Actual" interchange as these two components are separated in our ACE. Scheduled interchange can be arranged, confirmed and implemented, however Actual interchange cannot be directly coordinated in a parallel electric system by virtue of provisions in a standard. If we are referring only to scheduled interchange then we offer the following definitions: **Arranged Interchange:** A planned energy transfer between a source BA and a sink BA that has met all the requirements necessary for submittal to the IA.
Ed Riley-CA ISO, CA ISO	An energy transfer between source and sink BAs where all requirements have been met that are necessary to submit the interchange request to the Interchange Authority.
Doug Hils for MISO CA Wkg Group	The state where all arrangements necessary to submit the interchange request to the Interchange Authority have been made, *and the IA requests and receives approvals in order to perform required validation.*

Patti Metro for FRCC (15)	Circular – when developing a definition the word that is being defined should not be used in the definition. The following definition is suggested: The end result of all commercial activity for a specified transaction, enabling the PSE to submit a desired transaction to the Interchange Authority.
The use of Interchange is a proper noun ---- Ask Al.	

6. Suggested changes to definitions: Confirmed Interchange: The state where the Interchange Authority has verified the Arranged Interchange and is ready to submit it to the Balancing Authorities.	
Summary Consideration: Confirmed Interchange: The state where the Interchange Authority has verified the Arranged Interchange and is provided to the Balancing Authorities.	
Commenter(s)	**Comments**
Kathleen Goodman-ISO NE; Theodore G. Pappas-NYSRC; Gregory Campoli-NYISO; Karl Tammer for RTO/ISO Council (9) Guy Zito for NPCC CP9 Wkg Group(13)	ISO-NE (NYSRC, NYISO, RTO/ISO)suggests the following wording; "The state where the Interchange Authority has verified the Arranged Interchange and is ready to submit it to all Balancing Authorities including intermediate BAs."
Steven Cobb-SRP	Arranged Interchange that has been verified by the Interchange Authority to meet all requirements for submittal to the Source and Sink Balancing Authorities.
Ed Riley-CA ISO, CA ISO	An energy transfer that has been verified by the IA to meet all requirements for submittal to the source and sink BAs.
Shirley Buckmier-BPAT; Robert Schwermann for WECC Int Wkg Grp (26)	We are assuming that the CI standard is only referring to "Scheduled" and not "Actual" interchange as these two components are separated in our ACE. Scheduled interchange can be arranged, confirmed and implemented, however Actual interchange cannot be directly coordinated in a parallel electric system by virtue of provisions in a standard. If we are referring only to scheduled interchange then we offer the following definitions: **Confirmed Interchange:** An Arranged Interchange that has been verifier\ed by the IA to meet all requirements for submittal to the source and sink BA.
Doug Hils for MISO CA	The state where the Interchange Authority has ~~verified~~ *validated* the Arranged Interchange and ~~is ready to~~ submit*s*

Wkg Group	it to the Balancing Authorities.
Peter Burke-American Trans Co	The state where the Interchange Authority has verified the Arranged Interchange. The suggested change was to clarify the definition. The original definition had the Confirmed Interchange as something ready to be submitted but not yet submitted to the BA. The concern was in the definition of Implemented Interchange were the BA enters the Confirmed Interchange but per the original definition a Confirmed Interchange has not been sent to the BA.

6. Suggested changes to definitions: Implemented Interchange: The state where the Balancing Authority enters the Confirmed Interchange into its area control error equation.	
Summary Consideration: The team added, "net scheduled interchange component" to the end of the definition.	
Commenter(s)	**Comments**
Ed Riley-CA ISO, CA ISO	An energy transaction where the source and sink Balancing Authorities enter the Confirmed Interchange into their area control error equations and ramp generation in equal amounts and opposite directions to effect delivery of the energy.
Kathleen Goodman-ISO NE; Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)	ISO-NE suggests the following wording; " The state where the Balancing Authority <u>utilizes</u> the Confirmed Interchange <u>in its hourly dispatch</u>."
This comment is related to DC ties and this issue is still open.	
Karl Tammer for RTO/ISO Council (9); Gregory Campoli-NYISO	modify to state that the interchanges should be included in dispatch solutions, which includes ACE.
Shirley Buckmier-BPAT; Steven Cobb-SRP; Robert Schwermann for WECC Int Wkg Grp (26)	We are assuming that the CI standard is only referring to "Scheduled" and not "Actual" interchange as these two components are separated in our ACE. Scheduled interchange can be arranged, confirmed and implemented, however Actual interchange cannot be directly coordinated in a parallel electric system by virtue of provisions in a standard. If we are referring only to scheduled interchange then we offer the following definitions: **Implemented Interchange:** Confirmed Interchange that has been entered into the source and sink BA's ACE equation.

Roman Carter for Southern Co Generation (10)	If this definition is approved, it will require changes to the ACE equation to include this (or reference it in the definition of NSI). There are a lot of different variations of “interchange” in the proposed standard. I don’t believe this will eliminate any confusion. As an added note, the ACE equation in the CI Standard Reference Document is also incorrect.
Doug Hils for MISO CA Wkg Group	Question: If the BA receives notification of Confirmed Interchange from the IA and enters the information into a scheduling system one month ahead, what state is it in until the schedules run in real-time where it becomes Scheduled Interchange?

7. Do you agree with the proposed requirements and measurements in section 401?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Alan Johnson-Mirant		1	Okay with the requirement, but have a couple of questions about the measures section. First it's unclear to me what is meant by the phrase "…or the system that calculates the area control error equation." When would this not be the BA? Secondly, if evidence is allowed to be provided on a net basis (instead of individual), fail to see how compliance can be measured.
The phrase was added to ensure that whatever way the BA puts the Implemented Interchange values into the system (automatic system or manual system) that the values correspond to the information provided by the IA. The BA must implement what the IA tells them to implement. This could be done using individual or net values. The measure only addresses the fact that the BA did what the IA told them to do.			
Ev Lucenti-Power Decisions		1	If "implement Confirmed Interchange" refers to implementing the schedule change, then there needs to be a time frame of 1 hour before the schedule change to verify and confirm the upcoming "implantation of Confirmed Interchange."
The confirmation and verification takes place before this time. This measure only addresses the fact that the BA did what the IA told them to do.			
Roman Carter for Southern Co Generation (10); Marc Butts for Southern Co Svcs(9)		1	As stated in question 1, it is suggested that IA communication be provided to the IDC (an involved party to the transaction for Eastern Interconnect) for the Arranged Interchange to transition to a Confirmed Interchange.
The team agrees that the individual Interchange information must be provided to the IDC.			
Bert Gumm-Idaho Pwr		1	Unsure. The language is very vague and many individuals I've spoken with have communicated several differing interpretations.
The team will attempt to clarify the measures based on all the submitted comments.			
Patti Metro for FRCC (15)	1		For clarification, is the evidence that is required in 401(b)(1)(i) the rolling three months worth of values described in the compliance monitoring portion of the standard?
The compliance review will select from the stored data a sample period (several hours or days) and evaluate compliance.			
Karl Tammer for RTO/ISO Council (9); Gregory Campoli-		1	Evidence should include all transactions, rather than be limited to those considered purely in tie

NYISO			line control (ACE).
All transactions that require identification will be evaluated. Pseudo Ties are not scheduled by the IA			
Kathleen Goodman-ISO NE; Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)		1	Consistency with our position that DC Inter Area Ties should be treated as Interchange. Measurements – b.1 "Evidence must include all the transactions not just those in the ACE equation…", (include all DC tie flows)
Ed Riley-CA ISO, CA ISO	1		The evidence should include all transactions (dynamics etc.), whether or not they specifically feed into the ACE calculation.
All transactions that require identification will be evaluated. Pseudo Ties are not scheduled by the IA			
Pete Henderson / Khaqan Khan-The IMO-The IMO		1	There may be cases where DC ties are an interconnection between two BA's. Such aspects about DC inter Area ties needs to be addressed as an Interchange.
All transactions that require identification will be evaluated. Pseudo Ties are not scheduled by the IA			
Robert Schwermann for WECC Int Wkg Grp (26)		1	Yes, we agree with the requirement as written, but feel that due to the fact that we are not sure what the interchange process is it is difficult to set a specific requirement. WECC would suggest that a defined process with timelines and a central process be defined. If NERC declines to give specific methodology in the development of Standards, WECC would reserve the right to develop such specific methodology that may or may not be compatible with other interconnected NERC regions.
???			
Mark Creech for TVA (4)	1		Pending clarification the word "evidence".
Susan Morris for SERC (1)	1		However, more clarification is needed for the statement in Section 401.b.1.i requiring evidence demonstrating that Confirmed Interchange was implemented in the Balancing Authority's ACE equation. How do you prove that each transaction is in your ACE equation? EMS? The term "evidence" must be defined.
Al DiCaprio (4)-PJM	1		Yes, BAs must implement what the IA has verified.

William Smith-Allegheny Power	1		
Gerald Rheault-Manitoba Hydro	1		
James Spearman/Florence Belser (7)-PSC of SC	1		
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Doug Hils for MISO CA Wkg Group	1		
Peter Burke-American Trans Co	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		
Ron Gunderson-NB PPD	1		
Scott Moore for SPP ORWG (8)	1		
Shirley Buckmier-BPAT	1		
Steven Cobb-SRP	1		
Ed Davis-Entergy	1		
Tom Hawley-We Energies	1		

8. Do you agree with the proposed compliance monitoring process in section 401?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Lloyd Linke for MAPP RRC and OC (9)			It is not clear that Item 4(i) will provide the information required to monitor compliance. It could be interpreted as simply providing the information that was provided by the IA to the BA and not what the BA actually implemented. The correct measure would be to verify that the actual Implemented Interchange entered into the BA's ACE equation was the same as that sent to it by the IA.
Ron Gunderson-NB PPD		1	It is not clear that Item 4(i) will provide the information required to monitor compliance. It could be interpreted as simply providing the information that was provided by the IA to the BA and not what the BA actually implemented. The correct measure would be to verify that the actual Implemented Interchange entered into the BA's ACE equation was the same as that sent to it by the IA. Please clarify the terms block or ramp schedule.
The team agrees with the commenter that the intent was to ensure that what the iA sent to the BA was in fact what the BA implemented.			
Ev Lucenti-Power Decisions		1	Check by investigation as the result of a complaint. Verify process is document during on-site reviews.
The process will be verified during the on-site audit. The audit team will also be required to verify the process by including analysis of actual system data.			
John Horakh-MAAC		1	Section 401 (d) (1) requires compliance within the first year to be demonstrated by self-certification. This should be demonstrated by audit.
Patti Metro for FRCC (15)		1	The following is suggested as a more grammatical re-wording for 401(d)(1): Each Balancing Authority shall demonstrate compliance by self-certification to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation. In 401(d)(2), is the initial compliance review the self-certification described in 401(d)(1)? What is the difference between the audit [401(d)(1)(i)] and the spot check [401(d)(1)(ii)]? If the

			spot check is some type of self-certification submittal not an actual on-site visit, a more descriptive term such as random check could be used with an explanation of what the check would include. n 401(d)(2)(iv), a complaint must be lodged within 60 days of the incident, and in 401(d)(4)(i) a rolling 3 months worth of values must be maintained. It is, therefore, implied that the Compliance Monitor only has 30 days to complete the appropriate investigation. In 401(d)(3) the performance-reset period is tied to not meeting the requirement 401(a). Shouldn't the compliance monitoring process be linked to the measures which are in 401(b) rather than the requirements? The measures are supposed to be the specific items to look at to insure that you are meeting the requirement For 401(d)(4)(i), how will the Compliance Monitor be able to determine that the appropriate values were used to calculate ACE? For 401(d)(4)(ii), Interchange data is either block or ramp. Does this imply that both block or ramp is acceptable, or is this just for data storage? If both are allowed, how is the data stored and would it be part of the rolling average?
The intent is to verify within the first year of any new standard that the entity is compliant. During the first year the self-certification will be done for all entities within the region. Compliance of some entities will also be demonstrated by an on-site visit (assuming that 1/3 of the regions entities will be audited every three years. Spot checks could be self-certification or an actual request for specific data. The Team will clarify the intent. Once the complaint has been initiated the data will be collected by the region for review. The investigation will use the collected data and not rely of the entities locally stored information. The compliance should be directly tied to the measurement, which is derived from the standard. The team will clarify this statement. The individual Interchange details will be obtained from the IA. The measure in 401 will determine if the BA implemented what the IA told then to implement. If there were both ramp and block schedules, the IA would be providing the desired Interchange for each time frame.			
Bert Gumm-Idaho Pwr		1	It appears to be less restrictive than the WECC RMS requirements and sanctions. We feel that the greater the requirement for performance, the greater the performance. Therefore, If this standard is approved, WECC should be allowed to maintain its' own, more stringent standards.
WECC always has the option of having more stringent requirements for its region.			

Shirley Buckmier-BPAT; Steven Cobb-SRP		1	The WECC currently has a Reliability Management System in place for monitoring reliability Standard and Policy compliance and assigning sanctions for non-compliance. BPAT believes that compliance monitoring and formulation of non-compliance sanctions should the responsibility of the local Reliability Council. The CI standard should state that the Regional Council's monitoring and sanction program shall be comparable to, or at least as restrictive , as those defined by the NERC Standard.
WECC always has the option of having more stringent requirements for its region.			
Robert Schwermann for WECC Int Wkg Grp (26)		1	The WECC currently has a Reliability Management System in place for monitoring reliability Standard and Policy compliance and assigning sanctions for non-compliance. WECC reserves the right to apply sanctions that are equivalent to or more restrictive than NERC standard sanctions.
WECC always has the option of having more stringent requirements for its region.			
Ed Riley-CA ISO, CA ISO	1		This standard impacts the WECC RMS program (which is filed with FERC and other appropriate regulatory organizations), and there may need to be a regional difference on measuring non-compliance and sanctions. This response applies to 401 through 404.
Alan Johnson-Mirant	1		Think its okay, but wondering whether the BA's 90 day data retention requirement is sufficient given that complaints can be lodged up to 60 days after an incident. Doesn't seem to leave the compliance monitor with a lot of time to take action.
Theodore G. Pappas-NYSRC; Gregory Campoli-NYISO; Kathleen Goodman-ISO NE Guy Zito for NPCC CP9 Wkg Group(13)	1		Although NYSRC (NYISO, ISO-NE) feels audits are desirable for demonstrating compliance, we are concerned that the potential exists for excessive audits
James Spearman/Florence Belser (7)-PSC of SC	1		The term "Compliance Monitor" should be better defined within the Standard itself. This applies to the IA, BA, etc. functions as well. Considering the variety of grid operating configurations in place (vertically integrated utilities, RTOs, etc.), some concepts for who will actually perform the functions outlined should be provided.

Gerald Rheault-Manitoba Hydro	1		
Joel Mickey-ERCOT	1		
Karl Tammer for RTO/ISO Council (9)	1		
Ken Githens-Allegheny Energy	1		
Marc Butts for Southern Co Svcs(9)	1		
Mark Creech for TVA (4)	1		
Doug Hils for MISO CA Wkg Group	1		
Scott Moore for SPP ORWG (8)	1		
Susan Morris for SERC (1)	1		
Tom Hawley-We Energies	1		
Roman Carter for Southern Co Generation (10)	1		
William Smith-Allegheny Power	1		
Al DiCaprio (4)-PJM	1		
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		
Peter Burke-American Trans Co	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		

Ed Davis-Entergy	1		

9. Do you agree with the proposed levels of noncompliance in section 401?			
Commenter(s)	**Yes**	**No**	**Comments**
Summary Consideration:			
Alan Johnson-Mirant		1	Please see response to question #4. *(I agree in part with the sanction philosophy, but I think that an additional level of gradation needs to be added. It strikes me that an entity that achieves 90% compliance on 1000 records has a greater negative impact on reliability than the entity that achieves 90% compliance on 10 records. As such the entity with the greater negative impact on reliability should be more severely sanctioned than the entity whose non-compliance results in less of an impact on reliability. I don't know where the breakpoints should be, but I believe consideration should be given to creating a few buckets (for example 0-100, 101 – 500, >500) and utilizing the four sanction levels within each bucket.)*
The team debated this issue several times. The problem with percentages versus numbers can result in the same arguments. If the 1000 records were all 1 MW transactions and the 10 records were all 1000 MW transactions the impact may be reversed of what one would logically think.			
Bert Gumm-Idaho Pwr		1	WECC, or other Regional Councils, should be allowed to deviate from the level set in the standard, so long as their requirements (sanctions) meet or exceed those required by the standard.
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Shirley Buckmier-BPAT		1	The Regional Councils should establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC.
The regions can establish more restrictive standards than NERC and in doing so can have different levels of non-compliance as long as those new levels are equal to or more restrictive than the NERC standards and are included in the standard.			
Steven Cobb-SRP; Robert Schwermann for WECC Int Wkg Grp (26)		1	The Regional Councils should establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC. The CI Standard does not define the assessment period for which sanctions will be calculated. Is it intended that this period be monthly? 11&12, 14&15, 17&18.
The regions can establish more restrictive standards than NERC and in doing so can have different levels of non-compliance as long as those new levels are equal to or more restrictive than the NERC standards.			

Assessment Period ???			
Ed Riley-CA ISO, CA ISO	1		See # 8 *(This standard impacts the WECC RMS program (which is filed with FERC and other appropriate regulatory organizations), and there may need to be a regional difference on measuring non-compliance and sanctions. This response applies to 401 through 404.)*
Doug Hils for MISO CA Wkg Group		1	What is a record? Is a monthly transaction a record, or is each hour, day, week a record?
A record is defined as the Interchange entry. It could cover a partial hour, an entire hour, or a longer period.			
Al DiCaprio (4)-PJM		1	It would seem inconsistent to have a standard that requires all schedules be implemented as agreed to, but then allow a 20% margin of error. Regions should decide compliance levels for interchange.
The standard does not permit any error. The levels of non-compliance are to assess the degree of non-compliance.			
Richard Kafka-Pepco		1	Again, this goal should be 100%. Much smaller ranges and a higher "low limit" for level 3.
The drafting team will consider modifying the ranges for non-compliance.			
Karl Tammer for RTO/ISO Council (9)	1		To encourage a high level of compliance, the ranges for the levels of non-compliance could be made tighter than what is proposed
Patti Metro for FRCC (15)		1	There is some concern whether there is a percentage less than 80% that is just as bad as having no records at all. Is 20% compliance really the same as 79%? This should be considered in determining Level 4 non-compliance.
The drafting team will consider modifying the ranges for non-compliance.			
Ev Lucenti-Power Decisions		1	There needs to be a penalty matrix that includes penalties for any sending or receiving parties that implement schedule changes without verification and agreement with the other party.
The standard is intended to do what the commenter is asking.			
Peter Burke-American Trans Co		1	How should lack of Implemented Interchange evidence be counted? What should be done with a BA that has no complaints against it but is unable to produce 20% worth of positive evidence? Positive evidence being something other than the fact that no other entities have

			filed a complaint with the audited BAs compliance monitor.
The three types of audits will provide some level of compliance. If an entity does not do what it is directed to do and there are no complaints will probably never occur.			
Gregory Campoli-NYISO; Kathleen Goodman-ISO NE; Pete Henderson/Khaqan Khan; Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)	1		For the purposes of bringing more clarity; The NYISO (ISO-NE; NYSRC; The IMO)proposes that as per "requirements" and "measurements" of standard 401, the wordings within section (e) Levels 1-3 of non-compliance should be changed to " ………confirm that implemented Interchange matches corresponding "Confirmed Interchange submitted by the Interchange Authority"
Gerald Rheault-Manitoba Hydro	1		Manitoba Hydro agrees with the percentages proposed but suggests that the wording of "Levels of Noncompliance" be changed from "corresponding Interchange Authority Interchange" to "corresponding Interchange Authority Confirmed Interchange" to clarify the intent.
James Spearman/Florence Belser (7)-PSC of SC	1		It must be recognized that any problem may result in reduced reliability whether originating from a small or large entity. The approach adopted by the SDT is compliance-based rather than performance-based. Is the objective good data or a reliable system? The PSCSC maintains that the real objective is reliability, and not complete transaction records. They are merely an indicator that the process mechanics are working.
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Marc Butts for Southern Co Svcs(9)	1		

Mark Creech for TVA (4)	1		
Raj Rana-AEP	1		
Roman Carter for Southern Co Generation (10)	1		
Ron Gunderson-NB PPD	1		
Scott Moore for SPP ORWG (8)	1		
Susan Morris for SERC (1)	1		
William Smith-Allegheny Power	1		
Tom Hawley-We Energies	1		
Ed Davis-Entergy	1		

10. Do you agree with the proposed compliance monitoring process in section 402?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Bert Gumm-Idaho Pwr		1	The language is very vague and many individuals I've spoken with have communicated several differing interpretations
The drafting team will incorporate comments into a revised version which hopefully will clarify the standard.			
Gregory Campoli-NYISO; Kathleen Goodman-ISO NE; Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)		1	The NYISO (ISO NE, NYSRC) suggest the following wording (b) vii, "Each Reliability Authority, Balancing Area, and Transmission Service Provider has been notified and provided approval or denial.
This measure is only intended to evaluate whether or not approvals have been obtained. It does not evaluate notification.			
Patti Metro for FRCC (15)		1	In 402(a)(1), clarification should be provided for the terms "valid" and "balanced". These terms are very unclear and subjective. In 402(b)(1)(vii)(1), there is confusion on what is meant by a reliability related change. For example, could the RA change the ramp rate that is under the purview of the BA without the BA having to agree again or is a reliability change something more specific than this example?
The RA reliability related change would be to request a change in interchange to relieve a transmission overload. That change would abide by the BA ramp restrictions.			
Peter Burke-American Trans Co		1	The way this requirement reads is that the IA shall verify that Arrange Interchange is balanced and valid. Suggestion: The Interchange Authority shall submit Arrange Interchange's to the required Reliability Authority, Balancing Authority and Transmission Service Provider for the purpose of consideration of the Arrange Interchange. The Interchange Authority shall transition an Arrange Interchange to a Confirmed Interchange when and if the required Reliability Authority, Balancing Authority and Transmission Service Provider provide their approval.

			Measures: Measure (1)(vii)(1) seems out of place in this standard This requirement focuses on Arranged Interchanges coming from a PSE. This measure should either be included in a stand-alone standard or the requirements in this standard should be expanded. (Please see comment for question 21) *(This standard fails to address changes to a Confirmed Interchange or Implemented Interchange determined necessary by a Reliability Authority. Changes from a PSE seem to align with this standard except for the above comments. Requirement 404 only requires communication with entities when an Interchange has transitioned from an Arrange Interchange to a Confirmed Interchange. There is no requirement for the IA to make additional notification about changes. The SDT should add additional requirements to this standard to address changes to Confirmed Interchange or Implemented Interchange.)*
???			
Raj Rana-AEP		1	See comments under #5. *(This standard must provide guidelines to the parties involved in interchange for specific timing for requesting, approving or implementing interchange schedules from the reliability standpoint. As proposed, this standard requires PSEs to submit interchange schedules tag directly to IAs only, The IA, in turn, processes this information and sends the tag information to other entities involved in the schedule. This serial notification process will add time to the approval process. As a PSE, we would prefer that minimum notification time of 20 minutes be maintained and not increased. We suggest that IA be kept in the loop, however, same as today, when a tag is submitted by the a PSE, this information must go out to all involved entities in parallel. This will minimize the notification time.)*
Timing is a business practice. If entities can agree to Interchange with less than 20 minutes notice then that interchange should be allowed to take place.			
Robert Schwermann for WECC Int Wkg Grp (26)		1	Yes we agree, but who is the authority and the process. It goes back to the statement in #7. We think that NERC needs to define who specifically will be responsible for what function. Currently the Control area has specific functions relegated to them and we feel that NERC needs to continue to assign responsibility to specific functions for specific entities. As stated earlier, if NERC departs from its present mindset then this should be well stated and the reliability regions should be encouraged to develop their own specific methodologies.
???			

Roman Carter for Southern Co Generation (10) Marc Butts for Southern Co Svcs (9)	1	1	It is recommended that ramp rate be added as required reliability data. Since there is no standard stating a default ramp rate (as Policy 3 prescribes), it is recommended that the rate be a required piece of data for the BA to checkout in its approval process. If a Standard is established providing a standard ramp rate for the Eastern and Western Interconnect, the ramp rate would only be required in a "Request for Interchange" if it was different from the Standardized rate. Also, the SAR specifically mentions which reliability data is required as a minimum. This Standard just verifies that certain data is provided for. Are we to interpret that this verifiable data is the minimum amount acceptable? It is suggested that Requirement 402 (b) (1) be reworded to say "For each Arranged Interchange transitioned to Confirmed Interchange, the Interchange Authority shall show evidence that it has verified the following minimum amount of required data:"
If there is additional data required or expected we need to insert those items in this list. The ramp rate information is included in 402 (b) (1) (v).			
Mark Creech for TVA (4)	1		The words "balance and evidence" should be clearly defined in this SAR. TVA feels that 402(b)(1)(vii)(1) should be changed to 402(b)(1)(viii), and should state that at a request for a reliability related change by a Reliability Authority, no other entity approvals are required.
Shirley Buckmier-BPAT Steven Cobb-SRP	1		See point #2 under question #23. *(2. The CI Standard does not address processes, responsibilities, or ramifications associated with the correct or erroneous denial of an Interchange Transaction. Being "Held Hostage" by the Coordinate Interchange process can impact Balancing Authorities in several ways (Reference Document page 5). In the past NERC has promoted standardization of rules for all reliability regions. NERC, in this standard departs from that policy and opts for a more generic approach.)*
Susan Morris for SERC (1)	1		However, more clarification is needed for the statement in Section 402.b.1 requiring "for each Arranged Interchange transitioned to Confirmed Interchange, the Interchange Authority shall show evidence that it verified….." The term "evidence" must be defined.
Al DiCaprio (4)-PJM	1		Yes, NERC needs the standard to obligate IAs to validate the Arranged Interchage that they

			recieive.
William Smith-Allegheny Power	1		
Alan Johnson-Mirant	1		
Ed Riley-CA ISO, CA ISO	1		
Gerald Rheault-Manitoba Hydro	1		
James Spearman/Florence Belser (7)-PSC of SC	1		
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Karl Tammer for RTO/ISO Council (9)	1		
Ken Githens-Allegheny Energy	1		
Doug Hils for MISO CA Wkg Group	1		
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		
Richard Kafka-Pepco	1		
Ron Gunderson-NB PPD	1		
Scott Moore for SPP ORWG (8)	1		
Tom Hawley-We Energies	1		
Ed Davis-Entergy	1		
Ev Lucenti-Power Decisions			No Comment
Lloyd Linke for MAPP RRC and OC (9)			The MAPP Regional Reliability Council has no comment on this aspect of the Standard.

11. Do you agree with the proposed compliance monitoring process in section 402?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Ed Riley-CA ISO, CA ISO			See # 8 (This standard impacts the WECC RMS program (which is filed with FERC and other appropriate regulatory organizations), and there may need to be a regional difference on measuring non-compliance and sanctions. This response applies to 401 through)
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Bert Gumm-Idaho Pwr		1	It appears to be less restrictive than the WECC RMS requirements and sanctions. We feel that the greater the requirement for performance, the greater the performance. Therefore, If this standard is approved, WECC should be allowed to maintain its' own, more stringent standards.
Regional difference are permitted but should be included in this standard.			
Shirley Buckmier-BPAT; Steven Cobb-SRP; Robert Schwermann for WECC Int Wkg Grp (26)		1	See comments under question #8 *(The WECC currently has a Reliability Management System in place for monitoring reliability Standard and Policy compliance and assigning sanctions for non-compliance. BPAT believes that compliance monitoring and formulation of non-compliance sanctions should the responsibility of the local Reliability Council. The CI standard should state that the Regional Council's monitoring and sanction program shall be comparable to, or at least as restrictive , as those defined by the NERC Standard.)*
Regional difference are permitted but should be included in this standard.			
Alan Johnson-Mirant		1	Process may be okay but have a couple of questions. One, if under part (2)(iv) complaints can be lodged up to 60 days after the incident is the requirement for the IA to retain data for 90 days (3 months) sufficient? Secondly, under part (5) the compliance monitor is to verify IA data by comparing to entities including the PSE and TSP. However, I didn't observe any data retention requirements in the standard for either the PSE or TSP. Shouldn't there be so that the compliance monitor can do its job?
Once the complaint is logged, the region will collect the specific data required to conduct its investigation. The 90 day windows permits the timely collection of such data. The region will then conduct the investigation and complete that investigation as quickly as possible. ??? Data retention requirements for PSE and TSP, is that by contract???			

John Horakh-MAAC		1	Section 402 (d) (1) requires compliance within the first year to be demonstrated by self-certification. This should be demonstrated by audit.
Patti Metro for FRCC (15)		1	We have the same questions in regards to the compliance monitoring process for 402 as provided for 401, therefore, refer to the response to question 8. In addition, for 402(d)(5), how will the comparing of data be accomplished? References to keeping data are included in 401 and 403 for the RA, BA and TSP, however, this portion of the standard references the PSE having data, but there is no reference in the standard for a PSE to maintain any data. *(The following is suggested as a more grammatical re-wording for 401(d)(1): Each Balancing Authority shall demonstrate compliance by self-certification to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation. In 401(d)(2), is the initial compliance review the self-certification described in 401(d)(1)?* *What is the difference between the audit [401(d)(1)(i)] and the spot check [401(d)(1)(ii)]? If the spot check is some type of self-certification submittal not an actual on-site visit, a more descriptive term such as random check could be used with an explanation of what the check would include. In 401(d)(2)(iv), a complaint must be lodged within 60 days of the incident, and in 401(d)(4)(i) a rolling 3 months worth of values must be maintained. It is, therefore, implied that the Compliance Monitor only has 30 days to complete the appropriate investigation. In 401(d)(3) the performance-reset period is tied to not meeting the requirement 401(a). Shouldn't the compliance monitoring process be linked to the measures which are in 401(b) rather than the requirements? The measures are supposed to be the specific items to look at to insure that you are meeting the requirement* *For 401(d)(4)(i), how will the Compliance Monitor be able to determine that the appropriate values were used to calculate ACE? For 401(d)(4)(ii), Interchange data is either block or ramp. Does this imply that both block or ramp is acceptable, or is this just for data storage? If both are allowed, how is the data stored and would it be part of the rolling average?)*
ADD COMMENTS FROM 401			
Peter Burke-American Trans Co	1		Number (5) list the Purchasing/Selling Entity but there is no requirement currently in this standard that requires the PSE to retain any evidence. What evidence does the SDT expect the Compliance Monitor to get from the PSE? Requirement 403 states that the RA, BA and TSP need only to provide evidence that they responded to a request from the IA. What evidence does the SDT expect the Compliance Monitor to receive from the necessary RAs, BAs and TSPs? If a RA, BA or TSP only retains the minimum amount of evidence then all they would have is evidence showing a response, which might not include information about the request.

Theodore G. Pappas-NYSRC; Kathleen Goodman-ISO NE; Guy Zito for NPCC CP9 Wkg Group(13)Gregory Campoli-NYISO	1		Although the NYSRC (ISO-NE, NYISO) feels audits are desirable for demonstrating compliance, we have concerns that the potential exists for excessive audits.
William Smith-Allegheny Power	1		
James Spearman/Florence Belser (7)-PSC of SC	1		
Joel Mickey-ERCOT	1		
Karl Tammer for RTO/ISO Council (9)	1		
Gerald Rheault-Manitoba Hydro	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Marc Butts for Southern Co Svcs(9)	1		
Mark Creech for TVA (4)	1		
Doug Hils for MISO CA Wkg Group	1		
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		
Al DiCaprio (4)-PJM	1		

Roman Carter for Southern Co Generation (10)	1		
Ron Gunderson-NB PPD	1		
Scott Moore for SPP ORWG (8)	1		
Tom Hawley-We Energies	1		
Ed Davis-Entergy	1		
Susan Morris for SERC (1)	1		
Ev Lucenti-Power Decisions			No Comment

12. Do you agree with the proposed levels of noncompliance in section 402?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Peter Burke-American Trans Co			Is the following example correct? An Interchange Authority transitions 10 Arrange Interchanges to Confirmed Interchanges in the audited 3 months and 1 of those 10 is missing "Interchange duration is defined". That one would be counted against the IA and that IA should receive a level one non-compliance.
Ed Riley-CA ISO, CA ISO			See # 8 *(This standard impacts the WECC RMS program (which is filed with FERC and other appropriate regulatory organizations), and there may need to be a regional difference on measuring non-compliance and sanctions. This response applies to 401 through)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Shirley Buckmier-BPAT		1	See comments under question #9 *(The Regional Councils should establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC.)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Steven Cobb-SRP; Robert Schwermann for WECC Int Wkg Grp (26)		1	See comments under question #9 *(The Regional Councils should establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC. The CI Standard does not define the assessment period for which sanctions will be calculated. Is it intended that this period be monthly?) 1&12, 14&15, 17&18.*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			

<table>
<tr><td>Alan Johnson-Mirant</td><td></td><td>1</td><td>Please see response to question #4. (I agree in part with the sanction philosophy, but I think that an additional level of gradation needs to be added. It strikes me that an entity that achieves 90% compliance on 1000 records has a greater negative impact on reliability than the entity that achieves 90% compliance on 10 records. As such the entity with the greater negative impact on reliability should be more severely sanctioned than the entity whose non-compliance results in less of an impact on reliability. I don't know where the breakpoints should be, but I believe consideration should be given to creating a few buckets (for example 0-100, 101 – 500, >500) and utilizing the four sanction levels within each bucket.)</td></tr>
<tr><td colspan="4">The team debated this issue several times. The problem with percentages versus numbers can result in the same arguments. If the 1000 records were all 1 MW transactions and the 10 records were all 1000 MW transactions the impact may be reversed of what one would logically think.</td></tr>
<tr><td>Al DiCaprio (4)-PJM</td><td></td><td>1</td><td>It would seem inconsistent to have a standard that requires all schedules be implemented as agreed to, but then allow a 20% margin of error. Regions should decide compliance levels for interchange.</td></tr>
<tr><td colspan="4">The standard does not permit non-compliance but addresses levels for non-compliance. The drafting team will review the band width of non-compliance.</td></tr>
<tr><td>Bert Gumm-Idaho Pwr</td><td></td><td>1</td><td>WECC, or other Regional Councils, should be allowed to deviate from the level set in the standard, so long as their requirements (sanctions) meet or exceed those required by the standard.</td></tr>
<tr><td colspan="4">Regional differences must be included in this standard.</td></tr>
<tr><td>Doug Hils for MISO CA Wkg Group</td><td></td><td>1</td><td>What is a record? Is a monthly transaction a record, or is each hour, day, week a record?</td></tr>
<tr><td colspan="4">A record is each data entry. It could be apartial hour interchange, an hour interchenage, or a multi-hour interchange.</td></tr>
<tr><td>Patti Metro for FRCC (15)</td><td></td><td>1</td><td>We have the same questions in regards to the levels of noncompliance for 402 as provided for 401, therefore, refer to the response to question 9. (There is some concern whether there is a percentage less than 80% that is just as bad as having no records at all. Is 20% compliance really the same as 79%? This should be considered in determining Level 4 non-compliance.)</td></tr>
<tr><td colspan="4">The standard does not permit non-compliance but addresses levels for non-compliance. The drafting team will review the band width of non-compliance.</td></tr>
<tr><td>Richard Kafka-Pepco</td><td></td><td>1</td><td>Again, I do not understand why such a large percentage of "incorrect" would be allowed.</td></tr>
</table>

The standard does not permit non-compliance but addresses levels for non-compliance. The drafting team will review the band width of non-compliance.			
Gerald Rheault-Manitoba Hydro	1		Manitoba Hydro agrees with the concept of using percentage compliance for this item; however the wording of the "Levels of Noncompliance" is unclear as to exactly how this percentage is to be determined and over what time frame (a year ,a month, etc). This should be clarified.
Gregory Campoli-NYISO; Karl Tammer for RTO/ISO Council (9)	1		To encourage a high level of compliance, the ranges for the levels of non-compliance could be made tighter than what is proposed.
James Spearman/Florence Belser (7)-PSC of SC	1		It must be recognized that ***any*** problem may result in reduced reliability whether originating from a small or large entity. The approach adopted by the SDT is compliance-based rather than performance-based. Is the objective good data or a reliable system? The PSCSC maintains that the real objective is reliability, and not complete transaction records. They are merely an indicator that the process mechanics are working.
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Kathleen Goodman-ISO NE	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Marc Butts for Southern Co Svcs(9)	1		
Mark Creech for TVA (4)	1		
William Smith-Allegheny Power	1		
Pete Henderson / Khaqan Khan-	1		

The IMO-The IMO			
Raj Rana-AEP	1		
Roman Carter for Southern Co Generation (10)	1		
Ron Gunderson-NB PPD	1		
Scott Moore for SPP ORWG (8)	1		
Susan Morris for SERC (1)	1		
Theodore G. Pappas-NYSRC	1		
Tom Hawley-We Energies	1		
Ed Davis-Entergy	1		
Guy Zito for NPCC CP9 Wkg Group(13)	1		
Ev Lucenti-Power Decisions			No Comment

13. Do you agree with the proposed requirements and measurements in section 403?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Bert Gumm-Idaho Pwr		1	The language is very vague and many individuals I've spoken with have communicated several differing interpretations
Based on the comments we have received, the drafting team will clarify the document.			
Doug Hils for MISO CA Wkg Group		1	The measurements imply that out of thousands of transactions, the participant can be judged Level 4 non-compliant if it misses one transaction. We disagree with the Regional exemption, as a BA, ERCOT should interface with the IA
Since this measure is evaluated because of a complaint, any missing information for result in the entity being judged non-compliant level 4. ERCOT regional difference was a part of the original SAR.			
Peter Burke-American Trans Co		1	The way this currently reads, the RA, BA and TSP would be required to approve all Arrange Interchange requests submitted by the IA. Suggestion: The RA, BA and TSP shall respond to Arranged Interchange submitted by an IA. The RA, BA and TSP shall notify the IA if the submitted Arranged Interchange has their approval or denial with respect to their functional responsibilities.
???			
Robert Schwermann for WECC Int Wkg Grp (26)		1	See comments #7 & #10 *(Yes, we agree with the requirement as written, but feel that due to the fact that we are not sure what the interchange process is it is difficult to set a specific requirement. WECC would suggest that a defined process with timelines and a central process be defined. If NERC declines to give specific methodology in the development of Standards, WECC would reserve the right to develop such specific methodology that may or may not be compatible with other interconnected NERC regions.) (Yes we agree, but who is the authority and the process. It goes back to the statement in #7. We think that NERC needs to define who specifically will be responsible for what function. Currently the Control area has specific functions relegated to them and we feel that NERC needs to continue to assign responsibility to specific functions for specific entities. As stated earlier, if NERC departs from its present mindset then this should be well stated and the reliability regions should be encouraged to develop their own specific methodologies.)*

???			
Ron Gunderson-NB PPD		1	The measure is very ambiguous without a timing requirement. It could be interpreted that a response within a year meets the standard. At a minimum there should be a minimum time prior to the start of the interchange that the various entities need to respond by in order to meet the standard.
Timing requirement would be a business issue			
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		The type of evidence needs to be defined e.g. schedules, tape recordings or other documentation
Alan Johnson-Mirant	1		The last part of requirement 1 is not clear. Propose replacing "… reliable with respect to their functional responsibilities" with "…will result in no adverse reliability impact with respect to their functional responsibilities."
Al DiCaprio (4)-PJM	1		Yes, at a minimum all Reliability entities must be obligated to respond to the IA, since they ensure the integrity of the transmission system.
William Smith-Allegheny Power	1		
Gerald Rheault-Manitoba Hydro	1		
Gregory Campoli-NYISO	1		
James Spearman/Florence Belser (7)-PSC of SC	1		
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Karl Tammer for RTO/ISO Council (9)	1		
Kathleen Goodman-ISO NE	1		

Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Marc Butts for Southern Co Svcs(9)	1		
Mark Creech for TVA (4)	1		
Patti Metro for FRCC (15)	1		
Theodore G. Pappas-NYSRC	1		
Tom Hawley-We Energies	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		
Roman Carter for Southern Co Generation (10)	1		
Scott Moore for SPP ORWG (8)	1		
Shirley Buckmier-BPAT	1		
Steven Cobb-SRP	1		
Ed Davis-Entergy	1		
Susan Morris for SERC (1)	1		
Guy Zito for NPCC CP9 Wkg Group(13)	1		
Ed Riley-CA ISO, CA ISO			
Ev Lucenti-Power Decisions			No Comment

14. Do you agree with the proposed compliance monitoring process in section 403?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Ed Riley-CA ISO, CA ISO			See # 8 *(This standard impacts the WECC RMS program (which is filed with FERC and other appropriate regulatory organizations), and there may need to be a regional difference on measuring non-compliance and sanctions. This response applies to 401 through)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Robert Schwermann for WECC Int Wkg Grp (26)		1	See comments under question #8 *(The WECC currently has a Reliability Management System in place for monitoring reliability Standard and Policy compliance and assigning sanctions for non-compliance. WECC reserves the right to apply sanctions that are equivalent to or more restrictive than NERC standard sanctions.)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Shirley Buckmier-BPAT; Steven Cobb-SRP		1	See comments under question #8 *(The WECC currently has a Reliability Management System in place for monitoring reliability Standard and Policy compliance and assigning sanctions for non-compliance. BPAT believes that compliance monitoring and formulation of non-compliance sanctions should the responsibility of the local Reliability Council. The CI standard should state that the Regional Council's monitoring and sanction program shall be comparable to, or at least as restrictive , as those defined by the NERC Standard.)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Bert Gumm-Idaho Pwr		1	The standard requires proof of performance to a Compliance Monitor yet no "Levels of Noncompliance" are listed in 403(e). The sanctions would not apply, therefore it would not be enforceable. A defined time frame is also required.
This measure applies when an investigation by complaint has been started. The entity must provide the required information and if it can't it would be judged level 4 non-compliant.			
John Horakh-MAAC		1	Section 403 (d) (1) requires compliance within the first year to be demonstrated by self-certification. This should be demonstrated by audit. Section 403 (d) (2) requires that subsequent to the initial compliance review, compliance is verified only as the result of a complaint. At a minimum, compliance should also be verified by audit at least once every three

			years, similar to the verification requirements in Section 401 (d) (2) and Section 402 (d) (2).
The audit team will consider this in the next version???			
Alan Johnson-Mirant		1	Process may actually be okay, but wanted to point out a couple of things. One, I think the data retention requirement is unclear. The three-month requirement is listed as a subpart of part (3), which is directed at entities found to be non-compliant. This can be interpreted to mean that there is no data retention requirement for compliant entities. Structuring the section in a fashion similar to part (d) of section 402 could clear this up. I'll also raise the 60-day complaint period versus 90 days of data as a concern. Finally, under part (4) the compliance monitor is to verify BA, RA, PSE and TSP data by comparing to the IA's data. However, I don't see in the standard any data retention requirements in the standard for the PSE.
Patti Metro for FRCC (15)		1	We have the same questions in regards to the compliance monitoring process for 403 as provided for 401, therefore, refer to the response to question 8. In addition, why have the audits and spot checks been removed from the compliance monitoring process for 403? Also, as discussed in question 11 there is no reference in the standard for the PSE to maintain any data. *(The following is suggested as a more grammatical re-wording for 401(d)(1): Each Balancing Authority shall demonstrate compliance by self-certification to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation. In 401(d)(2), is the initial compliance review the self-certification described in 401(d)(1)?* *What is the difference between the audit [401(d)(1)(i)] and the spot check [401(d)(1)(ii)]? If the spot check is some type of self-certification submittal not an actual on-site visit, a more descriptive term such as random check could be used with an explanation of what the check would include. In 401(d)(2)(iv), a complaint must be lodged within 60 days of the incident, and in 401(d)(4)(i) a rolling 3 months worth of values must be maintained. It is, therefore, implied that the Compliance Monitor only has 30 days to complete the appropriate investigation. In 401(d)(3) the performance-reset period is tied to not meeting the requirement 401(a). Shouldn't the compliance monitoring process be linked to the measures which are in 401(b) rather than the requirements? The measures are supposed to be the specific items to look at to insure that you are meeting the requirement*

			For 401(d)(4)(i), how will the Compliance Monitor be able to determine that the appropriate values were used to calculate ACE? For 401(d)(4)(ii), Interchange data is either block or ramp. Does this imply that both block or ramp is acceptable, or is this just for data storage? If both are allowed, how is the data stored and would it be part of the rolling average?)
Three types of audits provide …			
Peter Burke-American Trans Co	1		Why in number (4) is the PSE included? The PSE is not listed in the requirements for this standard. What information would the Compliance Monitor expect to get or be required to receive from a PSE?
James Spearman/Florence Belser (7)-PSC of SC	1		It must be recognized that ***any*** problem may result in reduced reliability whether originating from a small or large entity. The approach adopted by the SDT is compliance-based rather than performance-based. Is the objective good data or a reliable system? The PSCSC maintains that the real objective is reliability, and not complete transaction records. They are merely an indicator that the process mechanics are working.
William Smith-Allegheny Power	1		
Al DiCaprio (4)-PJM	1		
Gerald Rheault-Manitoba Hydro	1		
Gregory Campoli-NYISO	1		
Joel Mickey-ERCOT	1		
Karl Tammer for RTO/ISO Council (9)	1		
Kathleen Goodman-ISO NE	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		

Marc Butts for Southern Co Svcs(9)	1		
Mark Creech for TVA (4)	1		
Doug Hils for MISO CA Wkg Group	1		
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		
Roman Carter for Southern Co Generation (10)	1		
Ron Gunderson-NB PPD	1		
Scott Moore for SPP ORWG (8)	1		
Tom Hawley-We Energies	1		
Susan Morris for SERC (1)	1		
Theodore G. Pappas-NYSRC	1		
Guy Zito for NPCC CP9 Wkg Group(13)	1		
Ed Davis-Entergy	1		
Ev Lucenti-Power Decisions			No Comment

15. Do you agree with the proposed levels of noncompliance in section 403?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Ed Riley-CA ISO, CA ISO			See # 8 *(This standard impacts the WECC RMS program (which is filed with FERC and other appropriate regulatory organizations), and there may need to be a regional difference on measuring non-compliance and sanctions. This response applies to 401 through)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Robert Schwermann for WECC Int Wkg Grp (26)		1	See comments under question #9 *(As stated in #8 The Regional Councils may establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC. The CI Standard does not define the assessment period for which sanctions will be calculated. Is it intended that this period be monthly? 11&12, 14&15, 17&18.)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Shirley Buckmier-BPAT		1	See comments under question #9 *(The Regional Councils should establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC.)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Steven Cobb-SRP		1	See comments under question #9 *(The Regional Councils should establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC. The CI Standard does not define the assessment period for which sanctions will be calculated. Is it intended that this period be monthly?)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Alan Johnson-Mirant		1	If we're going to measure and monitor compliance for this requirement, there should be a penalty for non-compliance.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			

Ron Gunderson-NB PPD		1	There are no levels of non-compliance specified.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Scott Moore for SPP ORWG (8)		1	Why couldn't the levels of noncompliance parallel those of 401 and 402 in utilizing percentages of responses to requests for evidence?
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Lloyd Linke for MAPP RRC and OC (9)		1	There are no levels of compliance specified.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Bert Gumm-Idaho Pwr		1	The "Levels of Noncompliance" in 403 (e) are "Not Specified". Does this infer that the sanctions proceed directly to step 4?
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
James Spearman/Florence Belser (7)-PSC of SC		1	No proposed levels of noncompliance provided.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Peter Burke-American Trans Co		1	Is the following assumption correct: If the BA, RA or TSP reviewed 100 Arranged Interchanges and 1 out of that 100 has no positive evidence that they responded to the Arrange Interchange that that RA, BA or TSP would be given a level four non-compliance. Positive evidence is evidence provided by the RA, BA or TSP. The IA could have evidence that they received a response but that would not benefit the RA, BA or TSP.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			

Gerald Rheault-Manitoba Hydro		1	The wording for this section is ambiguous. When using the term “Evidence not available or provided”, is it supposed to mean that the entity could not provide evidence because the requirement was not being done or because even if the requirement was being met the entity was not maintaining acceptable records so the performance could be monitored. This is not clear from the wording. The level of non compliance for not fulfilling the requirements should be more severe than for not having adequate records
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn’t respond and therefore is non-compliant.			
Mark Creech for TVA (4)		1	TVA feels that section 403 should have the same levels of non-compliance as sections 401 and 402.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn’t respond and therefore is non-compliant.			
Doug Hils for MISO CA Wkg Group		1	The measurements imply that out of thousands of transactions, the participant can be judged Level 4 non-compliant if it misses one transaction.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn’t respond and therefore is non-compliant.			
Patti Metro for FRCC (15)		1	Why are the levels of noncompliance different in this portion of the standard from those in 401 and 402? Isn’t a % also appropriate in 403?
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn’t respond and therefore is non-compliant.			
Tom Hawley-We Energies		1	
Gregory Campoli-NYISO; Karl Tammer for RTO/ISO Council (9)	1		Levels of noncompliance utilizing percentages of responses to requests for evidence, similar to those in 401 and 402 may be applicable
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Kathleen Goodman-ISO NE	1		

Ken Githens-Allegheny Energy	1		
Marc Butts for Southern Co Svcs(9)	1		
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		
William Smith-Allegheny Power	1		
Roman Carter for Southern Co Generation (10)	1		
Al DiCaprio (4)-PJM	1		
Susan Morris for SERC (1)	1		
Theodore G. Pappas-NYSRC	1		
Guy Zito for NPCC CP9 Wkg Group(13)	1		
Ed Davis-Entergy	1		
Ev Lucenti-Power Decisions			No Comment

16. Do you agree with the proposed requirements and measurements in section 404?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Bert Gumm-Idaho Pwr		1	We feel that "all entities" requires clarification. The standard makes no mention of the PSE yet following some discussion it is felt that that LSE/GPE need to be informed, in addition to any Transmission Operator or Balancing Authority.
Marc Butts for Southern Co Svcs(9); Roman Carter for Southern Co Generation (10)		1	As stated previously, it is suggested the IA shall communicate with the IDC.
Mark Creech for TVA (4)		1	The Coordinate Interchange Reference Document does not agree with standard 400-Coordinate Interchange section 404. The statement "all parties involved" is used in the reference document, and the statement "all entities involved" is used in the SAR. The SAR and the reference document need to be consistent with terms and words. Also, the SAR needs to explicitly state what parties or entities are to be contacted by the Interchange Authority. Note: Under the current policy the adjacent control areas are "all parties" that we confirm interchange transactions. The sink control area having the responsibility to confirm the entire transaction. If these "parties" are the ones referred to as being "all parties" then we can agree to this section.
Doug Hils for MISO CA Wkg Group		1	The measurements imply that out of thousands of transactions, the IA can be judged Level 4 non-compliant if it misses one transaction. We disagree with the Regional exemption, as a BA, ERCOT should interface with the IA

Peter Burke-American Trans Co		1	This requirement seems to place a heavy burden on the IA. The IA receives a request from a PSE and then solicits the necessary RA's, TSP's and BA's for rulings. Once all the required rulings have been received it seems that they should only have to notify the submitting PSE and the approving RA's, TSP's and BA's. The requirement would force them to also notify all other entities that were playing a role in the submitted interchange. It seems reasonable that once an interchange has gotten a ruling, the IA should notify the submitting PSE along with the RA's, TSP's and BS's that were solicited, but it should be the role of the PSE to notify all other involved entities. You use the word "interchange" in the Requirement but change it to "transaction" in the Measures. What is the difference? If no difference exists then it would be beneficial to use only one word. What does the SDT mean by "Final Status"? It seems that the requirement has the IA notifying entities if the submitted Arrange Interchange was approved or not. The words "final status" seems to imply something more than that.
Robert Schwermann for WECC Int Wkg Grp (26)		1	Same comments as #7, #10, #13 *(Yes, we agree with the requirement as written, but feel that due to the fact that we are not sure what the interchange process is it is difficult to set a specific requirement. WECC would suggest that a defined process with timelines and a central process be defined. If NERC declines to give specific methodology in the development of Standards, WECC would reserve the right to develop such specific methodology that may or may not be compatible with other interconnected NERC regions.) (Yes we agree, but who is the authority and the process. It goes back to the statement in #7. We think that NERC needs to define who specifically will be responsible for what function. Currently the Control area has specific functions relegated to them and we feel that NERC needs to continue to assign responsibility to specific functions for specific entities. As stated earlier, if NERC departs from its present mindset then this should be well stated and the reliability regions should be encouraged to develop their own specific methodologies.)*
Ron Gunderson-NB PPD		1	See below. Either the standard needs to require a response from each BA or the compliance monitoring process needs to change. *(Item (3) (i) in the compliance monitoring process requires IA's to keep three months of data showing that each interchange request was responded to, but there is no requirement in the standard for a BA to respond.)*
Alan Johnson-Mirant	1		Think that all entities that could be a party to the Interchange should be specifically mentioned (e.g., RA, BA, TSP, PSE) instead of using the phrase "all entities" such that it is not left up to interpretation as to whom the IA must communicate with.

Pete Henderson / Khaqan Khan-The IMO-The IMO	1		The type of evidence needs to be defined e.g. tape recordings
Al DiCaprio (4)-PJM	1		
Gerald Rheault-Manitoba Hydro	1		
Gregory Campoli-NYISO	1		
James Spearman/Florence Belser (7)-PSC of SC	1		
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Karl Tammer for RTO/ISO Council (9)	1		
Kathleen Goodman-ISO NE	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
William Smith-Allegheny Power	1		
Patti Metro for FRCC (15)	1		
Raj Rana-AEP	1		
Theodore G. Pappas-NYSRC	1		
Tom Hawley-We Energies	1		
Ed Davis-Entergy	1		

Susan Morris for SERC (1)	1		
Scott Moore for SPP ORWG (8)	1		
Shirley Buckmier-BPAT	1		
Steven Cobb-SRP	1		
Guy Zito for NPCC CP9 Wkg Group(13)	1		
Ed Riley-CA ISO, CA ISO			
Richard Kafka-Pepco			
Ev Lucenti-Power Decisions			No Comment

17. Do you agree with the proposed compliance monitoring process in section 404?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Ed Riley-CA ISO, CA ISO			See # 8 *(This standard impacts the WECC RMS program (which is filed with FERC and other appropriate regulatory organizations), and there may need to be a regional difference on measuring non-compliance and sanctions. This response applies to 401 through)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Alan Johnson-Mirant		1	My concerns are similar to those expressed in response to question 14. In addition, I think item (3)(i) is incorrectly written. I propose replacing it with the following: "Rolling three months worth of hourly Interchange records that indicate that the status of each Arranged Interchange was communicated to the BA, RA, TSP and PSE as appropriate." *(Process may actually be okay, but wanted to point out a couple of things. One, I think the data retention requirement is unclear. The three-month requirement is listed as a subpart of part (3), which is directed at entities found to be non-compliant. This can be interpreted to mean that there is no data retention requirement for compliant entities. Structuring the section in a fashion similar to part (d) of section 402 could clear this up. I'll also raise the 60-day complaint period versus 90 days of data as a concern. Finally, under part (4) the compliance monitor is to verify BA, RA, PSE and TSP data by comparing to the IA's data. However, I don't see in the standard any data retention requirements in the standard for the PSE.)*
Bert Gumm-Idaho Pwr		1	The standard requires proof of performance to a Compliance Monitor yet no "Levels of Noncompliance" are listed in 404(e). The sanctions would not apply, therefore it would not be enforceable. A defined time frame is also required.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
John Horakh-MAAC		1	Comments: Section 404 (d) (1) requires compliance within the first year to be demonstrated by self-certification. This should be demonstrated by audit. Section 404 (d) (2) requires that subsequent to the initial compliance review, compliance is verified only as the result of a complaint. At a minimum, compliance should also be verified by audit at least once every three years, similar to the verification requirements in Section 401 (d) (2) and Section 402 (d) (2).

Patti Metro for FRCC (15)		1	We have the same questions in regards to the compliance monitoring process for 404 as provided for 401, therefore, refer to the response to question 8. In addition, for 404(d)(3)(i), because the measurement for 404 is to provide final status it does not make sense that there would be compliance monitoring for a rolling three months that would indicate that each IA request was responded to. Also, as discussed in question 11 there is no reference in the standard for the PSE to maintain any data *(The following is suggested as a more grammatical re-wording for 401(d)(1): Each Balancing Authority shall demonstrate compliance by self-certification to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation.* *In 401(d)(2), is the initial compliance review the self-certification described in 401(d)(1)?* *What is the difference between the audit [401(d)(1)(i)] and the spot check [401(d)(1)(ii)]? If the spot check is some type of self-certification submittal not an actual on-site visit, a more descriptive term such as random check could be used with an explanation of what the check would include.* *n 401(d)(2)(iv), a complaint must be lodged within 60 days of the incident, and in 401(d)(4)(i) a rolling 3 months worth of values must be maintained. It is, therefore, implied that the Compliance Monitor only has 30 days to complete the appropriate investigation.* *In 401(d)(3) the performance-reset period is tied to not meeting the requirement 401(a). Shouldn't the compliance monitoring process be linked to the measures which are in 401(b) rather than the requirements? The measures are supposed to be the specific items to look at to insure that you are meeting the requirement)*
Ron Gunderson-NB PPD		1	Item (3) (i) in the compliance monitoring process requires IA's to keep three months of data showing that each interchange request was responded to, but there is no requirement in the standard for a BA to respond.
Robert Schwermann for WECC Int Wkg Grp (26)		1	See comments under question #8 *(The WECC currently has a Reliability Management System in place for monitoring reliability Standard and Policy compliance and assigning sanctions for non-compliance. WECC reserves the right to apply sanctions that are equivalent*

			to or more restrictive than NERC standard sanctions.)
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Shirley Buckmier-BPAT; Steven Cobb-SRP		1	See comments under question #8 *(The WECC currently has a Reliability Management System in place for monitoring reliability Standard and Policy compliance and assigning sanctions for non-compliance. BPAT believes that compliance monitoring and formulation of non-compliance sanctions should the responsibility of the local Reliability Council. The CI standard should state that the Regional Council's monitoring and sanction program shall be comparable to, or at least as restrictive , as those defined by the NERC Standard.)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
James Spearman/Florence Belser (7)-PSC of SC	1		It must be recognized that ***any*** problem may result in reduced reliability whether originating from a small or large entity. The approach adopted by the SDT is compliance-based rather than performance-based. Is the objective good data or a reliable system? The PSCSC maintains that the real objective is reliability, and not complete transaction records. They are merely an indicator that the process mechanics are working.
Peter Burke-American Trans Co	1		Why in number (4) is the PSE included? Nowhere in this standard does the PSE have to maintain and collect evidence? What does the SDT expect the Compliance Monitor to receive from the RA, BA and TSP? (The PSE is not included because the PSE's responsibilities are not part of this standard.) Reviewing standard 403, the RA, BA or TSP does not have to collect evidence that they received confirmation back for the IA once they have approved an Interchange. So how can an IA say that they have performed something when those entities that they need to communicate with are not required to save the communication?
Ed Davis-Entergy	1		
William Smith-Allegheny Power	1		
Al DiCaprio (4)-PJM	1		
Gerald Rheault-Manitoba Hydro	1		

Gregory Campoli-NYISO	1		
Joel Mickey-ERCOT	1		
Karl Tammer for RTO/ISO Council (9)	1		
Kathleen Goodman-ISO NE	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Marc Butts for Southern Co Svcs(9)	1		
Mark Creech for TVA (4)	1		
Doug Hils for MISO CA Wkg Group	1		
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		
Raj Rana-AEP	1		
Roman Carter for Southern Co Generation (10)	1		
Scott Moore for SPP ORWG (8)	1		
Susan Morris for SERC (1)	1		
Theodore G. Pappas-NYSRC	1		
Tom Hawley-We Energies	1		
Guy Zito for NPCC CP9 Wkg Group(13)	1		

Richard Kafka-Pepco			
Ev Lucenti-Power Decisions			No Comment

18. Do you agree with the proposed levels of noncompliance in section 404?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Ed Riley-CA ISO, CA ISO			See # 8 *(This standard impacts the WECC RMS program (which is filed with FERC and other appropriate regulatory organizations), and there may need to be a regional difference on measuring non-compliance and sanctions. This response applies to 401 through)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Robert Schwermann for WECC Int Wkg Grp (26)		1	See comments under question #9 *(As stated in #8 The Regional Councils may establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC. The CI Standard does not define the assessment period for which sanctions will be calculated. Is it intended that this period be monthly? 11&12, 14&15, 17&18.)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Shirley Buckmier-BPAT		1	See comments under question #9 *(The Regional Councils should establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC.)*
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Steven Cobb-SRP		1	See comments under question #9 (The Regional Councils should establish the levels of non-compliance as long as the levels are comparable to, or at least as restrictive, as those defined by NERC. The CI Standard does not define the assessment period for which sanctions will be calculated. Is it intended that this period be monthly?)
WECC standards can be more restrictive than the NERC standards however they must be included in the standard.			
Alan Johnson-Mirant		1	If we're going to measure and monitor compliance for this requirement, there should be a penalty for non-compliance.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			

Gerald Rheault-Manitoba Hydro		1	same comment as in #15 above *(The wording for this section is ambiguous. When using the term "Evidence not available or provided", is it supposed to mean that the entity could not provide evidence because the requirement was not being done or because even if the requirement was being met the entity was not maintaining acceptable records so the performance could be monitored. This is not clear from the wording. The level of non compliance for not fulfilling the requirements should be more severe than for not having adequate records)*
Bert Gumm-Idaho Pwr		1	The "Levels of Noncompliance" in 404(e) are "Not Specified". Does this infer that the sanctions proceed directly to step 4?
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
James Spearman/Florence Belser (7)-PSC of SC		1	No proposed levels of noncompliance provided.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Lloyd Linke for MAPP RRC and OC (9)		1	There are no levels of compliance specified.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Ron Gunderson-NB PPD		1	There are no levels of non-compliance specified.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Tom Hawley-We Energies		1	Levels not specified.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Mark Creech for TVA (4)		1	Same comment as question 15. *(TVA feels that section 403 should have the same levels of non-compliance as sections 401 and 402.)*

There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Patti Metro for FRCC (15)		1	We have the same questions in regards to the levels of noncompliance for 404 as provided for 403, therefore, refer to the response to question 15. *(Why are the levels of noncompliance different in this portion of the standard from those in 401 and 402? Isn't a % also appropriate in 403?)*
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Peter Burke-American Trans Co		1	Please reference question 15. The question asks how much lack of evidence is needed before a level four non-compliance is assigned to a IA. *(Is the following assumption correct: If the BA, RA or TSP reviewed 100 Arranged Interchanges and 1 out of that 100 has no positive evidence that they responded to the Arrange Interchange that that RA, BA or TSP would be given a level four non-compliance. Positive evidence is evidence provided by the RA, BA or TSP. The IA could have evidence that they received a response but that would not benefit the RA, BA or TSP.)*
Scott Moore for SPP ORWG (8)		1	See the response to Question 15. *(Why couldn't the levels of noncompliance parallel those of 401 and 402 in utilizing percentages of responses to requests for evidence?)*
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Gregory Campoli-NYISO; Karl Tammer for RTO/ISO Council (9)	1		Levels of noncompliance utilizing percentages of responses to requests for evidence, similar to those in 401 and 402 may be applicable.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Doug Hils for MISO CA Wkg Group		1	The measurements imply that out of thousands of transactions, the IA can be judged Level 4 non-compliant if it misses one transaction.
There is one defined level of non-compliance. The entity can either demonstrate that it responded (and is therefore compliant) or it didn't respond and therefore is non-compliant.			
Ed Davis-Entergy	1		

Al DiCaprio (4)-PJM	1		
William Smith-Allegheny Power	1		
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Kathleen Goodman-ISO NE	1		
Ken Githens-Allegheny Energy	1		
Marc Butts for Southern Co Svcs(9)	1		
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		
Raj Rana-AEP	1		
Theodore G. Pappas-NYSRC	1		
Roman Carter for Southern Co Generation (10)	1		
Susan Morris for SERC (1)	1		
Guy Zito for NPCC CP9 Wkg Group(13)	1		
Ev Lucenti-Power Decisions			No Comment
Richard Kafka-Pepco			

19. Do you agree with the concept that . . . losses will be handled as just another type of Interchange?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Kathleen Goodman-ISO NE; Pete Henderson / Khaqan Khan-The IMO; Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)		1	ISO-NE believes the issue of losses may appropriately be handled by mutual agreements or methodologies established between the BA's and the IA's.
Roman Carter for Southern Co Generation (10) Marc Butts for Southern Co Svcs(9)		1	According to the CI Standard Reference Document for self-provided losses, the IA will serve as the loss distributor by setting up individual transactions with the "intermediary" BAs on behalf of the Purchasing-Selling Entity. Are these individual transactions with the Intermediary BAs separate and independent from the original "Request for Interchange"? In today's terms, is the IA making separate "tags" with each TSP for the losses or is the IA simply asking the TSP to confirm the mw loss amounts allocated by the PSE for each TSP along the path in the original "Request for Interchange"? If it is the last scenario, which we believe to be so, the explanation for this needs to be more definitive and specific. Finally, are settlements (either financial or self-provided) for transmission losses a reliability issue? It appears to be a better topic for NAESB to establish the Standard for loss allocations.
Susan Morris for SERC (1) Ed Davis-Entergy		1	"The concept that Implemented Interchange requires equal and opposite use by two BA's in their ACE equations and that losses will be handled as just another type of Interchange when being settled as energy exchange" is misleading and does not conform to the examples contained in the CI Standard Reference Document Appendix C. This concept is reasonably close only when the transmission service losses of all intermediate Transmission Service Providers are settled financially. However, Interchange from the source BA is increased by the amount of losses provided in-kind and that loss provision must be identified as being associated with the original Interchange. Even the Reference Document identifies this loss provision as a "component" of a larger "composite" interchange.

			Also, separating the provision of losses from the principal Interchange will complicate the business practices associated with Interchange and cause the industry to incur additional unnecessary expense. Implementing this concept will increase the number of required Arranged Interchanges dramatically to accommodate the loss provision in-kind and will complicate the tracking of the Arranged Interchange and the associated losses provided in-kind. Finally, implementation of this concept is a change to existing business practices. This reliability standard should only reference existing business practices and should not attempt to implement new business practices. New business practices should be developed by NAESB. Therefore, we think this new business practice for provision of losses in-kind is without merit and an unnecessary complication to these NERC reliability standards.
Doug Hils for MISO CA Wkg Group		1	The Standard should recognize that the Net Scheduled Interchange for the IA must balance to zero, even if multiple BAs are involved along the path for proper delivery of losses - the Implemented Interchange in that example would not be equal and opposite between the two BAs. The Standard should capture loss provision in the coordination required of the IA and the BAs along the "path".
Gregory Campoli-NYISO		1	
Ken Githens-Allegheny Energy		1	
Gerald Rheault-Manitoba Hydro	1		Compensation for losses is a financial transaction and should regulated by the business standard process (NAESB responsibility), not the reliability process. This could be handled using either a financial settlement or return of energy.
Bert Gumm-Idaho Pwr	1		We agree, this is the method currently in use for CA's in the WECC today.
Mark Creech for TVA (4)	1		This statement also needs to reflect that losses may be handled by this or other approved methods.
Patti Metro for FRCC (15)	1		We agree with this concept, but were concerned whether the tool (OATI presently) developed would be able to process the number of transactions that might be required. In the example shown in the reference document, there would be a total of 5 transactions (1 main deal and 4

			transactions for losses) this could be cumbersome.
Robert Schwermann for WECC Int Wkg Grp (26)	1		We agree as this is present methodology that is successful
William Smith-Allegheny Power	1		
Alan Johnson-Mirant	1		
Al DiCaprio (4)-PJM	1		
James Spearman/Florence Belser (7)-PSC of SC	1		
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Karl Tammer for RTO/ISO Council (9)	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Steven Cobb-SRP	1		
Tom Hawley-We Energies	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		
Ron Gunderson-NB PPD	1		
Scott Moore for SPP ORWG (8)	1		
Shirley Buckmier-BPAT	1		

Ed Riley-CA ISO, CA ISO			
Ev Lucenti-Power Decisions			No Comment
Peter Burke-American Trans Co			

20. Do you agree that dynamic schedules would be covered by this standard as just another type of bilateral interchange?			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Patti Metro for FRCC (15)		1	We do agree that dynamic schedules would be covered by this standard, but think the standard should include some type of parameters on the electronic tag that supports dynamic schedules, such as, how much does the dynamic schedule have to change before the tag has to be changed? Today's process is a % of the dynamic schedule.
Robert Schwermann for WECC Int Wkg Grp (26)		1	We have no specific Yes/No answer. Dynamic Schedules need to be handled by the local reliability region. This is a difficult issue and needs to be handled on a regional basis with regional standards.
Bert Gumm-Idaho Pwr	1		This topic has been at the center of debate for some time. If it is covered by this standard there will be the need to have some flexibility for Regional differences.
Shirley Buckmier-BPAT		1	There needs to be recognition that the profile for a Dynamic Schedule has to include both the minimum and maximum expected values during the scheduling period, the reason is for reliable assessment of transmission capacity. Averages don't work. This should be coordinated with NERC's Dynamic Transfer Paper (reference document).
Scott Moore for SPP ORWG (8)	1		While dynamic schedules are bilateral interchange, the handling of losses and their true-up is significantly different from typical bilateral interchange. The standard and the reference document are silent on the treatment of losses for dynamic schedules.
Karl Tammer for RTO/ISO Council (9); Gregory Campoli-	1		Recognizing that Dynamic Schedules are a type of Dynamic Transfer and that psuedo ties are not included in this standard. Mention of this in the preamble may add clarity.

NYISO			
Mark Creech for TVA (4)	1		Pending an explicit definition of the term dynamic schedule.
Doug Hils for MISO CA Wkg Group	1		Including the treatment of losses
Steven Cobb-SRP	1		SRP strongly recommends that all Dynamic Transfers be subject to the Assessment, Confirmation, and Implementation processes defined in the Coordinate Interchange Standard. We believe that Dynamic Schedules and Pseudo Ties are identical in their function and their impacts to the interconnected system. The only difference between Dynamic Schedule and Pseudo Tie type Dynamic Transfers is that they affect different variables in the ACE equation. The argument that Pseudo Ties impact the Actual Interchange side of the ACE equation and should be excluded for this Standard exploits a technicality that compromises system reliability and places those entities that use Dynamic Schedules at a reliability and market disadvantage. If Dynamic Schedules provide visibility for a coordination and curtailment process that excludes Pseudo Ties, the user of the Dynamic Schedule will be subject to curtailments that may be exacerbated by Pseudo Ties that aren't curtailed. This type of process is contrary to SAR Market Interface Principle #2 "An Organization Standard shall not give any market participant an unfair competitive advantage." As with Dynamic Schedules, Pseudo Ties are not strictly limited to use by adjacent Balancing Authorities. They may extend across the boundaries of several Balancing Authorities and require contiguous transmission arrangements. As a result, Pseudo Ties must undergo the same kinds of reliability assessment given to Dynamic Schedules and other types of planned Interchange. Exempting Pseudo Ties from this Standard would indicate that existing Dynamic Schedules could be converted to Pseudo Ties and also be exempted from the Coordinate Interchange Standard process without impacting system reliability. This is simply not the case. Excluding Pseudo Ties from this Standard would seem to contradict the Standard's name:

			“Coordinate Interchange.”
Al DiCaprio (4)-PJM	1		
Ed Riley-CA ISO, CA ISO	1		
Gerald Rheault-Manitoba Hydro	1		
William Smith-Allegheny Power	1		
James Spearman/Florence Belser (7)-PSC of SC	1		
Joel Mickey-ERCOT	1		
John Horakh-MAAC	1		
Alan Johnson-Mirant	1		
Kathleen Goodman-ISO NE	1		
Ken Githens-Allegheny Energy	1		
Lloyd Linke for MAPP RRC and OC (9)	1		
Marc Butts for Southern Co Svcs(9)	1		
Roman Carter for Southern Co Generation (10)	1		

Ron Gunderson-NB PPD	1		
Pete Henderson / Khaqan Khan-The IMO-The IMO	1		
Raj Rana-AEP	1		
Richard Kafka-Pepco	1		
Susan Morris for SERC (1)	1		
Guy Zito for NPCC CP9 Wkg Group(13)	1		
Ed Davis-Entergy	1		
Theodore G. Pappas-NYSRC	1		
Tom Hawley-We Energies	1		
Ev Lucenti-Power Decisions			No Comment
Peter Burke-American Trans Co			

21. Does the standard adequately address the reliability requirements for implementing changes to the parameters of an already Implemented Interchange? For instance, if an emergency occurs, is the coordination defined by the requirements sufficient to ensure reliability is maintained or are additional coordination requirements needed? If so, please explain.

Summary Consideration:

Commenter(s)	Yes	No	Comments
Ev Lucenti-Power Decisions			401 states that confirmed interchange must be implemented exactly as agreed to in the interchange confirmation process. Does this extend to the situation described above? If the parameters are changed, is it a new "interchange"?
Karl Tammer for RTO/ISO Council (9); Pete Henderson/Khaqan Khan Gregory Campoli-NYISO	1	1	Defining the Emergency procedures in the Standard and the applicability of the standard in emergencies would add clarity.
Bert Gumm-Idaho Pwr		1	If it is not defined in this standard, then the development of an "Emergency" or "Curtailment/Adjustment" standard will be required. It currently is not defined in this standard.
James Spearman/Florence Belser (7)-PSC of SC		1	While the Standard references the Standard Reference Document, the PSCSC is concerned users may not hold the Reference Document in the same high regard that they hold the Standard itself. The PSCSC would prefer the key provisions of the Reference Document be rolled into the Standard itself.
Robert Schwermann for WECC Int Wkg Grp (26) Shirley Buckmier-BPAT		1	As we have stated earlier it tells us what, but does not tell us how. Is the emergency functionality covered in another standard? If not there should be specific emergency direction. Also refer to the previous comments about a general departure from present NERC specific directives

Kathleen Goodman-ISO NE; Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)		1	Standardized coordination modes and/or guidelines need to be defined or referred to within the standards to adequately address the reliability requirements. ISO-NE (NYSRC) believes more clarity is needed in defining what the Emergency procedures are in the Standard. Again, the Reference Document seems to holds these important details yet they are not clearly part of the Standard. Perhaps this needs to be addressed and coordinated with Standard 1000 Prepare for and Respond to Abnormal and Emergency Conditions.
Ken Githens-Allegheny Energy		1	The standard is unclear. Appendix B in the reference document does clarify what should happen. I personally do not like depending on an addition document to explain the standard. The standard should include all the information needed as a stand-alone document.
Lloyd Linke for MAPP RRC and OC (9) Ron Gunderson-NBPPD		1	Implemented Interchange changes also need to be adequately communicated and acknowledged by BA adjacent to but not in control of DC Ties between interconnections.
Patti Metro for FRCC (15)		1	That was a question we had. Why isn't there a requirement for the IA to communicate changes to a confirmed or implemented interchange? The reference document seems to imply that this would be covered under the requirements included in the standard, but we saw this as a "hole" and believe there should be something specific in the standard.
Peter Burke-American Trans Co		1	This standard fails to address changes to a Confirmed Interchange or Implemented Interchange determined necessary by a Reliability Authority. Changes from a PSE seem to align with this standard except for the above comments. Requirement 404 only requires communication with entities when an Interchange has transitioned from an Arrange Interchange to a Confirmed Interchange. There is no requirement for the IA to make additional notification about changes. The SDT should add additional requirements to this standard to address changes to Confirmed Interchange or Implemented Interchange.

Raj Rana-AEP		1	If timing requirement is too restrictive, it could affect the reliability. The standard should recommend or provide a guideline as to what is acceptable from the reliability standpoint.
Steven Cobb-SRP		1	See note #5 in question #23. *(402.b.1.vii.1 states: "For a reliability related change requested by a Reliability Authority, no other entity approvals are required." We suggest that the parties making the change MUST confirm emergency changes even though their approval is not required.)*
Ed Riley-CA ISO, CA ISO	1		Additional language may be required that better explains the inclusion of emergency procedures.
Alan Johnson-Mirant	1		From a reliability standpoint, I think the coordination is covered. However, the standard doesn't cover getting the changes back to the PSE, which I believe it should.
Al DiCaprio (4)-PJM	1		By handling changes (changes for commercial or changes for emergencies or changes for any other interchange-related activity) all in the same way (i.e. that all partities agree) is an appropriate NERC standard.
Mark Creech for TVA (4)	1		This statement addresses the reliability requirements as depicted in Figure 4 of the Coordinate Interchange Reference Document.
John Horakh-MAAC	1		Standard is adequate
Tom Hawley-We Energies	1		As long as changes are scrutinized in the same manner as initially arranged interchange.
William Smith-Allegheny Power	1		
Gerald Rheault-Manitoba Hydro	1		
Joel Mickey-ERCOT	1		

Marc Butts for Southern Co Svcs(9)	1		
Doug Hils for MISO CA Wkg Group	1		
Richard Kafka-Pepco	1		
Roman Carter for Southern Co Generation (10)	1		
Scott Moore for SPP ORWG (8)	1		
Susan Morris for SERC (1)	1		
Ed Davis-Entergy	1		

22. **Should a requirement for acknowledging the receipt of Confirmed Interchange from the Interchange Authority be included in the standard?**			
Summary Consideration:			
Commenter(s)	**Yes**	**No**	**Comments**
Ev Lucenti-Power Decisions		1	Not required if schedule changes are confirmed.
Gerald Rheault-Manitoba Hydro		1	A procedure requiring the BA and PSE to acknowledge receipt of Confirmed Interchange should not be included in the Standard. The compliance review process will determine whether proper notification was provided. If there is a need to have an acknowledgement process it should be part of the normal business practices related to this activity.
Gregory Campoli-NYISO; Kathleen Goodman-ISO NE; Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)		1	The NYISO (ISO-NE; NYSRC) understands this has been omitted due to its redundancy, however the Standard should clarify this and why.
Tom Hawley-We Energies		1	They should be informed, but not 'required' to acknowledge receipt to facilitate implementation.
Joel Mickey-ERCOT		1	
Ed Davis-Entergy		1	
John Horakh-MAAC		1	
Karl Tammer for RTO/ISO Council (9)		1	
Ed Riley-CA ISO, CA ISO		1	
William Smith-Allegheny Power		1	

Al DiCaprio (4)-PJM		1	
Bert Gumm-Idaho Pwr	1		BA's and PSE's should be required to acknowledge the receipt of Confirmed Interchange to ensure adequate communication for a reliably balanced system.
Robert Schwermann for WECC Int Wkg Grp (26)	1		How can Interchange be confirmed when the confirmation process does not include the entities that will implement said Interchange? A requirement needs to be included for reliability purposes; a tool such as the current E-Tag methodology is a must for reliability purposes.
Doug Hils for MISO CA Wkg Group	1		With regard to the BA: there has to be an audit trail to reflect which entity failed to perform its required operation. If the IA is to ensure the implementation of interchange, that acknowledgement is necessary.
Patti Metro for FRCC (15)	1		The BA and PSE should be required to acknowledge confirmed interchange from the IA. It is important for these entities be involved in the process because the BA and PSE are responsible for resources involved in the transactions.
Mark Creech for TVA (4)	1		The BA and PSE should be active in confirmed acknowledgments because any change or delay in the state of the transaction could directly affect resources of which they are responsible.
James Spearman/Florence Belser (7)-PSC of SC	1		The PSCSC believes the IA would certainly want such acknowledgement.
Alan Johnson-Mirant	1		Believe it would help to "complete the loop" and provide the compliance monitor with data to help it in performing its function.

Raj Rana-AEP	1		In order to keep proper accounting.
Scott Moore for SPP ORWG (8)	1		If there are passive approvals in the process, then the lack of acknowledgement can become a reliability issue.
Shirley Buckmier-BPAT	1		Bas and PSEs must acknowledge the receipt of Confirmed Interchange. How can interchange be confirmed when the confirmation process does not include the entities that will implement said interchange. A requirement needs to be included for reliability purposes; a tool such as the current E-Tag methodology is a must for reliability.
Steven Cobb-SRP	1		BAs and PSEs must acknowledge the receipt of Confirmed Interchange. How can Interchange be confirmed when the confirmation process does not include the entities that will implement said Interchange?
Ron Gunderson-NB PPD	1		Acknowledgement of BA's should required to provide positive feedback that the IA successfully notified the BA of a Confirmed Interchange
Ken Githens-Allegheny Energy	1		
Marc Butts for Southern Co Svcs(9)		1	
Pete Henderson / Khaqan Khan-The IMO-The IMO		1	
Peter Burke-American Trans Co		1	
Richard Kafka-Pepco		1	

Roman Carter for Southern Co Generation (10)		1	
Susan Morris for SERC (1)		1	
Lloyd Linke for MAPP RRC and OC (9)			The MAPP Regional Reliability Council has no comment on this aspect of the Standard.

23. Please provide other comments on the standard that you haven't provided in response to the previous questions in this document.	
Summary Consideration:	
Commenter(s)	**Comments**
William Smith-Allegheny Power	Allegheny Power feels that due to the importance of the associated Business Practice Standards currently being developed by NAESB, it is essential that these Business Practice Standards be implemented in conjunction with the standard. Also this SAR is a good candidate for field-testing prior to implementation.
Alan Johnson-Mirant	Overall, the drafting team has put together a very good document. The Reference Document is very helpful as well. The one area that may need additional debate is with respect to the Arranged Interchange cycle of the Interchange life cycle. The standard doesn't fully address activity occurring during this cycle, although it is considered to be part of the reliability period and not the market period (hence a NERC issue to resolve). I assume this was intentional since the reference document states that this standard covers the reliability related aspects of the Confirmed Interchange and Implemented Interchange cycles (p 4 of 18). That being the case, it seems that we need another standard developed within NERC to address this cycle. That would result in three separate standards/practices (2 in NERC, 1 in NAESB) to address the interchange transaction process. As an observation, it seems that we're heading down the wrong track to reach greater efficiency.
Bert Gumm-Idaho Pwr	Please refer to the WECC comments for this section.
Ed Riley-CA ISO, CA ISO	1. Exchanges across DC ties, psuedo ties, and dynamic exchanges should be specifically included in this standard. 2. There should be a requirement for adjacent BAs to perform pre-operating hour checkouts. 3. The standard should not go into effect until the industry has had a transition period and it has been field-tested. The standard should include all requirements identified in the SAR. These requirements must be in sufficient detail such that the standard is a stand alone document. The reference document should only contain supporting information and examples.

Kathleen Goodman-ISO NE Theodore G. Pappas-NYSRC Guy Zito for NPCC CP9 Wkg Group(13)	There is an outstanding issue with the inclusion of a monetary sanction matrix and what its implications are. ISO-NE has previously expressed concerns over its inclusion and maintains that the use of market mechanisms, where possible as well as letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance to reliability criteria and standards. Failure of NERC to gain authority through reliability legislation could result in NERC pursuing actions to implement "Plan B," a "voluntary" approach affording NERC the authority to perform these types of monetary sanctions. ISO-NE has also indicated that any posted Standard, with the included matrix, may not be supported. There are, however, proceedings at NERC by the Compliance Certification Committee (CCC) to address alternative sanction proposals and ISO-NE (NYSRC) will continue to work to oppose monetary sanctions. ISO-NE (NYSRC) recommends a more logical order to the Standard, (i.e., chronological sequence); "Implementation of Interchange" should be last, not first. ISO-NE (NYSRC) does not believe multiple IA's within a RA is a workable solution, furthermore, we feel that there may be a need for an Interconnection-wide IA for oversight. Effective Period – "The effective date upon the approval of the NERC Board of Trustees" is not a practical implementation. There needs to be a reasonable transition period built in, to allow Areas to make any necessary changes to achieve compliance. ISO-NE (NYSRC) believes all requirements must be documented and detailed in the Standard itself, not in the Reference Document. Any Reference Documents associated with a Standard should be used strictly as a training tool; the Standard should be a "stand-alone" document and be self-explanatory.

Gregory Campoli-NYISO	There is an outstanding issue with the inclusion of a monetary sanction matrix and what its implications are. ISO-NE, NYSRC, as well as NYISO, have previously expressed concerns over its inclusion and maintain that the use of market mechanisms where possible, as well as, letters of increasing degrees of severity and notifications to regulatory agencies are more effective in ensuring compliance to reliability criteria and standards. Failure of NERC to gain authority through reliability legislation could result in NERC pursuing actions to implement “Plan B,” a “voluntary” approach affording NERC the authority to perform these types of monetary sanctions. ISO-NE and NYSRC have indicated that any posted Standard, with the included matrix, will not be supported. There are, however, proceedings at NERC by the Compliance Certification Committee (CCC) to address alternative sanction proposals and NYISO will continue to work to oppose monetary sanctions. The NYISO also endorses the comments submitted by the ISO/RTO Council Standards Review Committee. The NYISO recommends a more logical order to the Standard, (i.e., chronological sequence); “Implementation of Interchange” should be last, not first. The Effective Period should allow for a reasonable transition period to allow Areas to make any necessary changes to achieve compliance. Field-testing this standard may be beneficial for the industry. All requirements must be complete and detailed in the Standard. The Reference Document should be used to provide examples and supplemental reference.
James Spearman/Florence Belser (7)-PSC of SC	1. While the Standard references the Standard Reference Document, the PSCSC is concerned users may not hold the Reference Document in the same high regard that they hold the Standard itself. The PSCSC would prefer the key provisions of the Reference Document be rolled into the Standard itself. 2. The Standard Reference Document states the Standard is performance-based. The PSCSC maintains that the real

	objective is reliability, and not complete transaction records. They are merely an indicator that the process mechanics are working. It seems there should be some additional penalty for reliability issues which arise from process transgressions.
Ken Githens-Allegheny Energy	AE would recommend any associated business practice standard be in place and implemented at the same time this standard is implemented.
Karl Tammer for RTO/ISO Council (9)	DC tie lines should be part of this standard, regardless of how the DC tie lines are modeled in a BA's area control algorithm, if the DC tie is an interconnection between two BAs. § Using the complete definition of the ACE equation, pointing out that the omitted components are not germane to this standard, would provide clarity. § Add requirement that adjacent BA's must check out with each other. § The Effective Period should allow for a reasonable transition period to allow Areas to make any necessary changes to achieve compliance. Field-testing this standard may be beneficial for the industry. § All requirements must be complete and detailed in the Standard. The Reference Document should be used to provide examples and supplemental reference.
Lloyd Linke for MAPP RRC and OC (9)	Particular care should be taken in determining impacts to BA's adjacent to DC Ties between interconnections. Communications affecting both Interconnections need to be verified. Provisions should be made to address Interchange supplied by a reserve sharing pool using CBM or TRM. During an emergency, the normal approval process takes too much time and should not be used.
Mark Creech for TVA (4)	TVA would prefer that this SAR is field tested prior to implementation. • This SAR appears to require extensive communication between all participants involved. So, depending upon the clarification of terms, in all the commented sections, development of communication protocols and appropriate tools that all participants must have to carry-out the intent of the SAR may-be required. • Coordinate Interchange Reference Document…pg 12 of 18. The statement suffcent information for all approval entities is a broad statement and needs clarification. What information required for one company may be defined as different for another.
Patti Metro for FRCC (15)	There is a concern that there should be a requirement for the IA to verify approvals from the RA and the Transmission Service Provider to complete reliability analysis. In this case, the BA should be notified of the approval prior to implementation of the interchange. Is this concern, included in what is addressed in Figure 1 of the reference document?

	Since the drafting team indicated in the conference call and the presentation at the January 2004 Standing Committee Meeting that because of the uncertainty of the Functional Model, there has not been much thought in the implementation of the standard, we advise that this standard be reviewed and revised as necessary based on the tasks of the entities identified in version 2 of the functional model. It's not clear, for example, that the BA's responsibility to approve interchange ramp rates is properly supported in the standard with the information to be provided (such as specific generator source/sink for some transactions)."
Pete Henderson / Khaqan Khan-The IMO-The IMO	(1) It is proposed that standard should follow a more logical order i.e. standard 401 re: "Implementation of Interchange" should be outlined at the end of the set of standards (2) We feel that a reasonable transition period should be given for the implementation of this standard to allow sufficient lead time to the Areas for achieving compliance. (3) The reference document/background is useful for the purposes of understanding the associated application modes of standard.
Robert Schwermann for WECC Int Wkg Grp (26) Shirley Buckmier-BPAT Steven Cobb-SRP	We suggest that the following definitions be added: - Source Balancing Authority The Balancing Authority in which the generator of a specific Interchange Schedule is located. - Sink Balancing Authority The Balancing Authority in which the load for a specific Interchange Schedule is located. "Source" and "Sink" are used throughout the document. In most cases they are accompanied by "Balancing Authority." In at least one case they aren't (402.b.1.i) We suggest that defining and utilizing Sink BA and Source BA terms will ensure clarity and consistency. 1. It is the WECC Interchange and Scheduling and Accounting Subcommittee (ISAS) view that the functional model throughout does not set parameters for the market to be held accountable for reliability criteria. We say it is a NAESB problem. We need to have specific language in the standards that states that ALL entities are accountable for complying

	with standards in order to participate in the interchange process. 2. NERC for many years has promoted standardization of rules for all reliability regions. NERC, in this standard, departs from that policy and opts for a more generic approach. It is the WECC view that the reliability and market operating entities need specific guidance such as the guidance that the current Policy 3 provides. If NERC is departing from this policy please state this in some form of statement that would create the necessity for regions such as WECC to develop their own standards based on the NERC new general specifications. 3. The CI Standard does not include a methodology for Assessment, Confirmation, and Implementation, of 'Intrachange' Schedules that may impact parallel paths in Adjacent Balancing Authority Areas. These schedules impact Interchange and should be coordinated. 4. The CI Standard does not address processes, responsibilities, or ramifications associated with the correct or erroneous denial of an Interchange Schedule. 5. 402.a.1. states: "The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange." We suggest the terms "balanced and valid" either be defined or replaced with a more definitive explanation. Is this statement referring to a single Interchange Schedule between two discrete BAs, or Net Scheduled Interchange between two BAs? How does the IA "balance" the Interchange? 6. In the Reference Document, page 8, the second bullet in the 402 Standard Measurement states: "Interchange is implemented by the source Balancing Authority and the sink Balancing Authority." The Standard states: "Interchange is between a source Balancing Authority and a sink Balancing Authority." Which statement is correct? 7. 402.b.1.vii.1 states: "For a reliability related change requested by a Reliability Authority, no other entity approvals are required." We suggest that the parties making the change MUST confirm emergency changes. 8. 404.b.1 states: "For each Arranged Interchange, the Interchange Authority shall provide evidence that it has

	communicated the appropriate final status to all entities involved in the transaction." What do "each", "final", and "all entities" mean? Could it be stated: "The Interchange Authority shall provide evidence that it has communicated to the Reliability Authority(s), Balancing Authority(s), and Transmission Service Provider(s) involved with the Interchange Transaction that the Interchange Transaction has been confirmed and it is approved for implementation." The term "Interchange Transaction" is used above based on its current NERC definition.
Ron Gunderson-NB PPD	Definition and scope of the Interchange Authority should be clarified in the functional model. Particular care should be taken in determining impacts to BA's adjacent to DC Ties between interconnections. Communications affecting both Interconnections need to be verified. Provisions should be made to address Interchange supplied by a reserve sharing pool using CBM or TRM. During an emergency, the normal approval process takes too much time and should not be used.
Scott Moore for SPP ORWG (8)	In the DC Tie section of the reference document: Regardless how the BA models the DC ties in his control algorithm, if the DC tie is an interconnection between two BAs, the DC ties should be incorporated into this standard. For example, a BA could model the tie as a load/generator and still use it as a connection to another BA. In the Terminology section of the reference document: To prevent confusion, the entire ACE equation should used in the reference document or a disclaimer stating that the omitted components are not relevant to this issue should be included.
Susan Morris for SERC (1)	Page 2 of the Coordinate Interchange Standard, version 1 lists terms referring to entities performing specific functions as defined in the Functional Model. Please add "Compliance Monitor" to this list of terms. The draft Standard makes references to the Compliance Monitor however; it does not explain the origin of this term.
Charles Yeung-Reliant	Reliant proposes that any ballot by the NERC RBB on the CI Standard not be taken until such time NERC-NAESB coordination on standards transition is in place. Reliant is concerned that the CI Standard in its proposed form falls significantly short of what industry needs to operate reliable systems and conduct business in markets. Though Reliant understands it is not within NERC's purview to develop business practices, the reality is that there may be severe impacts to the standards development process if the NERC CI Standard is approved absent an industry understanding of it's inter-relationship with the NAESB CI Business Standard. This is particularly important for the NERC CI Standard because of the drafting team's reliance on the NERC Functional Model White Paper, to guide in the definition of responsibilities of the functional areas to the NERC CI Standard. The Functional Model is focused on the needs for reliable operations, but assumes market designs and

	functions which may not be best suited for the industry in the near future. It is important to note that the Functional Model White Paper is a NERC Board approved document and not a result of the consensus stakeholder process of NAESB, tasked to develop business practices for the industry. NERC explains that the new NERC Reliability Standards will rely on other documents not a part of the mandatory standard. The manual states that, "These documents may explain or facilitate implementation of standards but do not themselves contain mandatory requirements subject to compliance review." Reliant understands this reference as requiring documents, such as the NAESB CI Business Practices (in development today) as one such document which the industry will rely upon. The difficulty that will be imposed on the industry by approving the NERC CI Standard before the NAESB CI Business Practices are ready is that when the NAESB development of the CI Business Practices gets more detailed, any changes that may be needed to reflect the market designs subsumed within the Business Practices, particularly in relationships and responsibilities between the various functional entities, will require NERC to undergo the entire SAR-Std process again for the same standard. This will delay implementation of the reliability standard and impose additional burden on the industry to re-do the NERC CI Standard.

Coordinate Interchange Standard Reference Document
Draft Version 4

- Introduction - Philosophy
- Relationship to the SAR
- Relationship to the Functional Model
- Terminology
- Timing
- Dynamic Transfers
- DC Ties
- Settlement of Losses
- Interchange Changes
- Appendix A – SAR and draft Standard requirement comparison
- Appendix B – Life Cycle Stages of Interchange
- Appendix C – Functional Model Technical Document - Losses

Introduction

This document explains the assumptions the Coordinate Interchange Standard Drafting Team (SDT) used to create the draft Standard.

<u>Standard Focuses on Reliability</u>

To date, both reliability and business concerns have driven the development of NERC's Policies. The Coordinate Interchange SAR focused on the reliability issues surrounding the process of approving and implementing energy transfers across BA boundaries (Interchange). Each BA uses Interchange values in calculating its ACE. The SAR did not delve into any of the business practices associated with Interchange since developing standards for business practices is outside the scope of NERC's Reliability Standards. Business Practices for energy transfers across BA boundaries are ~~to~~ being developed by NAESB. The SDT has been working cooperatively with its counterparts in NAESB to ensure that, to the extent practical, this new Coordinate Interchange Standard will not conflict with any associated business practices being developed by NAESB.

The NAESB Coordinate Interchange Business Practice (CIBP) Standard identifies market-supported processes to facilitate fair & equitable competitive interchange practices. The NAESB CIBP Standard requires that commercial and reliability data including the necessary front-end business arrangements be obtained by the PSE prior to the Interchange request being submitted to the IA. Upon receiving this information, the IA will then utilize the NERC CI Standard to transition the Interchange request from the Market period to the Reliability period as shown in Appendix B Figure 1.

<u>Standard is Performance-based</u>

Because the Standard is written as a "performance-based," standard, it does not require the use of specific tools, formats or methods to achieve compliance with the standard's requirements. For example, the E-Tagging process addressed NERC Policy is not required in the standard, neither is its use precluded. Similarly, manual processes such as the use of email, a phone, a fax, or any other mechanism is not precluded. This is consistent with the Standard's goal of focusing on reliability performance, rather than the processes that support that performance.

Standard is not a Replacement for Policy 3
This Standard is focused in its scope and is not intended to be a replacement for Policy 3. The requirements associated with this standard are intended to address reliability issues; therefore, the standard does not address issues associated with certification of Functional Model entities. The standard's requirements are assumed to be those associated with bilateral interchange (i.e. between a source and a sink, occurring at the same time in equal and opposite directions). The standard contains only those reliability requirements measurable for compliance.

The Director-Compliance and the SAC will decide on the need for field testing this standard. The SDT will develop an implementation plan that gives consideration to the practicalities of implementing this standard and may recommend waiting to implement this standard until some of the associated business practices or tools have been developed. The SDT will be seeking industry feedback on its implementation plan, as this standard is refined.

Relationship to the SAR

The SDT, as defined by the NERC Standards Development process, used the content of the Standard Authorization Request (SAR) as the basis for the corresponding Standard. SDTs are required to draft a standard that is within the scope of the associated SAR.

An example of an issue which some may consider part of "Coordinate Interchange" is communication by the IA of an implemented interchange to the existing Interchange Distribution Calculator (IDC) tool. Such a communication is not part of the requirements in the SAR and thus is not included in the standard.

Appendix A is a table that compares the Coordinate Interchange SAR's requirements to the requirements in the draft Coordinate Interchange Standard.

Relationship to Functional Model

The standard is based on Version 2 of the Functional Model.

Terms
The Standard (as well as the SAR from which it is derived) uses the terms defined in the NERC Functional Model. The Functional Model responsible entities used in the Standard or its companion Reference Document are:

- Interchange Authority (IA)
- Balancing Authority (BA)
- Reliability Authority (RA)
- Transmission Service Provider (TSP)
- Purchasing/Selling Entity (PSE)
- Transmission Operator (TOP)

Bilateral Interchange

Under the Functional Model, Interchange Authorities must be used to coordinate interchange that is 'bilateral' (i.e. between a source and a sink, occurring at the same time in equal and opposite directions). This standard focuses solely on bilateral interchange.
It has been discussed in various forums how many Interchange Authorities can exist. Neither the Functional Model nor this Standard imposes any upper or lower limit on the number of Interchange Authorities that can exist.

Number of Interchange Authorities
The Functional Model does not impose any limits on the number of Interchange Authorities that can exist. This standard only requires that an Interchange Authority be involved in coordinating Interchange.

Internal Interchange Activities
The Functional Model does not treat internal interchange that occurs within an energy market or within an RTO interchange in a special manner. For example, a Scheduling Agent that provides approved interchange instructions to internal BAs within an RTO market structure is assumed in this Standard to function as a BA's agent in its interactions with the IA. (See Functional Model Version 2 companion Technical Document Section 2.6 – Technical Discussion – Managing Bi-lateral Transactions – Scheduling Agents).

The relationships of the functions included in this Standard are consistent with those in the Functional Model. For example, in this Standard the BA is only to obtain the Implemented Interchange information from a single IA for each Confirmed Interchange. This does not preclude one physical entity from being certified by NERC to represent multiple functions in the interchange process. If certified, the same entity performing PSE activities could also perform IA activities and provide interchange information to the BAs for implementation.

Terminology

A major problem faced by both the Coordinate Interchange SAR DT and Standard DT has been terminology. The terminology problem is partially a result of the industry's inconsistent use of terms "*interchange*" "*transactions*" and "*schedules*". These terms have been used interchangeably to mean very different things. The SDT tried to correct the misunderstandings associated with these terms by developing precise definitions associated with the various steps in the decision making process that results in the data that is entered into the ***NET SCHEDULED INTERCHANGE*** term of the ACE equation.

Any discussion of ***INTERCHANGE*** must start with the use of the term as it applies to the control performance measure Area Control Error (ACE). ACE uses ***INTERCHANGE*** as a power flow (either agreed to obligation for power or metered power). Currently control areas perform the balancing function of the Functional Model and implement the agreement under the terms and conditions specified. NERC must ensure that Balancing Authorities implement the same agreement at the same time and in equal and opposite directions using criteria in the Functional Model.

ACE = (*Net Scheduled Interchange* – NET Actual Interchange) + B (Scheduled Frequency – Actual Frequency)

In order to understand the terminology used by this standard, refer to the graphic in **Appendix B** that shows the various stages in the life cycle of Interchange as addressed in this standard.

Interchange: Energy transfers that cross Balancing Authority boundaries.

Arranged Interchange: The state where the Purchasing/Selling Entity has obtained all necessary approvals to submit the Interchange to the Interchange Authority.

Confirmed Interchange: The state where the Interchange Authority has validated approvals and is ready to submit the Interchange to the Balancing Authorities.

Implemented Interchange: The state where the Balancing Authority enters the Confirmed Interchange into its area control error equation.

The Proposed Interchange stage of this process is outside the scope of this standard. In the Proposed Interchange stage, the PSE puts together the business arrangements for the interchange with TSPs, Generators and LSEs and obtains preliminary reliability approvals from RAs. At this stage, agreements (including transmission reservations) can be put together in a piecemeal fashion – but these business arrangements don't become an 'Arranged Interchange' until all the involved RA's and BA's give their preliminary approval to the PSE. These preliminary steps in the process weren't included in the scope of the SAR and aren't included in this draft standard.

The Standard covers the reliability-related aspects of the Confirmed Interchange and Implemented Interchange steps. The standard implies that prior to becoming an Arranged Interchange all business requirements associated with receiving agreement are settled; otherwise, the PSE would not receive consent from all the entities and the life cycle of the proposal would end before entering the reliability stages — those stages directly addressed by this standard.

Timing

Is the timing of the data exchange between entities addressed in this standard? No.
From a reliability perspective, it is only important that the required data be exchanged – not when the exchange occurs (except that the exchange must occur before the defined start date/time provided in the Arranged Interchange data).

How will the practicalities of timing be addressed?
The entities involved in this interchange process must address practical timing requirements such as minimum lead times so everyone involved has enough time to accomplish their tasks. The appropriateness of these times however, is a business issue and is outside the scope of this standard. If a function's timing is not met, it is assumed its approval will not be provided and the Interchange will not become an Implemented Interchange.

Will entities be held hostage to their approvals? What if an entity holds out so long as to render another entity's approval invalid?
"Approval" is more than just saying, 'YES' or 'NO'. While this standard does not specify the level of detail that must be included in each approval, most approvals are expected to be given in the form of 'conditional' approvals *{e.g. "This proposed agreement has my approval up to 5 minutes before the hour. If the IA has not returned its validation then the proposal is denied"}.* These conditional approvals will prevent an entity holding another set of entities hostage as the latter group awaits the former entities' response to a proposed interchange.

Dynamic Transfers

<u>Are dynamic transfers addressed in this standard?</u>
The use of dynamics schedules is a type of bilateral interchange that is covered by the requirements of this standard. The Implemented Interchange defined by the telemetered quantities associated with a dynamic schedule is applied to the Net Scheduled Interchange term of the ACE equation.

The use of pseudo-ties requires that both Balancing Authorities include the actual telemetered qualities in the Net Actual Interchange component of the ACE equation; therefore, pseudo-ties are not included in the standard.

DC Ties

<u>Are DC ties addressed in this standard?</u>

That depends on how the Balancing Authorities involved on either side of the DC tie handle the tie in their ACE equation.

- If a Balancing Authority is directly connected to a DC tie and includes the DC tie flow in its Net Scheduled Interchange component of the ACE equation, then, the DC tie Interchange is treated the same as any other Interchange.
- If a Balancing Authority is directly connected to a DC tie and models the tie as another load or generator in its area, the DC tie is not included in the Net Scheduled Interchange component of the ACE equation and is not addressed in this standard. (In this case, the Interchange is balanced internally like any other load or generation and doesn't cross Balancing Authority boundaries.)
- In the case of "flow through" Interchange, the BA connected directly to a DC tie would need to include the Interchange in its Net Scheduled Interchange component of its ACE equation, because it would be receiving or delivering energy with other BAs across AC interfaces. In this case, the DC tie's Interchange will be submitted by the IA as a Confirmed Interchange to the BAs connected to the DC tie and is subject to this standard.

In all cases noted above, the BA that operates the DC tie would receive the Interchange information and be subject to the standard and responsible for notifying the IA of a DC tie trip and the associated Interchange change.

Settlement of Losses

<u>Are loss settlements addressed in this standard?</u>
The settlement of losses incurred when implementing interchange can be handled either as financial or as energy "payment in kind." In either case, loss settlement is primarily a business issue and only involves reliability when losses are handled as Interchange.

Losses will be handled conceptually in this standard as outlined in Version 1 of the Functional Model's Technical Discussion 1 document, "Interchange Scheduling Process — Figure 7," **Appendix C**. In that document, all bilateral schedules are equal and opposite in direction for the source and sink BAs and losses settled as energy are merely an interchange "component" of a larger "composite" interchange involving the generation, load, and intermediate BAs.

Interchange Changes

Once an Interchange has transitioned to the Confirmed or Implemented state, it is entirely possible that the Interchange parameters (i.e. MW, ramp start and stop, duration, etc.) may need to change due to business or reliability reasons. The change to an Interchange in one of these states does not eliminate the necessity for coordination to take place. While Figure 1 of Appendix B shows the coordination communications that take place when an Interchange is initially established, the subsequent figures in Appendix B reflect the similar coordination steps to effect a change in an Interchange.

Figure 2 of Appendix B shows a change (e.g., cancel, increase MW, decrease MW, change ramp or duration info, etc.) initiated by the PSE for non-reliability reasons once the Interchange has transitioned to a Confirmed Interchange. In this case, the PSE would make the same type business and reliability arrangement communications that it did prior to first requesting the Interchange. Subsequent steps also follow the same process. Although not shown, if an Interchange has already transitioned to an Implemented state, the same steps taken during the original coordination would be taken by the PSE and IA to affect the change requested by the PSE.

Figure 3 of Appendix B shows the steps required to change an Interchange during the Confirmed state, which occurs for reliability reasons. In this scenario, only a BA or RA can initiate the change and only the RA can communicate the requested change to the IA. The IA will still verify the interchange parameters are valid but the other entities do not have the opportunity to deny the transition from Arranged to Confirmed because it is for reliability reasons. The IA then communicates the Confirmed state of the Interchange to all parties as in the other scenarios.

Similarly, Figure 4 of Appendix B shows the steps required to change an Interchange during the Implemented state which occurs for reliability reasons. As in the scenario fro a reliability change during the Confirmed state, only a BA or RA may initiate the change and only the RA can communicate the requested change to the IA. The remaining coordination to implement the reliability-based change occurs as described previously.

Examination of the coordination to affect a change to an Interchange which has already gone Confirmed or Implemented shows that they reflect the same requirements which are required for the initial creation of the Interchange except that requirement 403 is not required for a reliability-based change.

Appendix A — SAR and Draft Standard Requirement Comparison

SAR Requirement	Standard Requirement	Standard Measurement	Comment
BA shall confirm (with the IA) its approval or denial of the requested Interchange Schedule.	**403 — Response to Interchange Authority** ~~1.1.~~The Reliability Authority, Balancing Authority, and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. Approval is an acknowledgement by these entities that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.	The Reliability Authority, Balancing Authority, and Transmission Service Provider must provide evidence that they responded to each request from an Interchange Authority.	Included
BAs shall implement Interchange Schedules exactly as agreed upon in the interchange confirmation process.	**401 — Implementation of Interchange** The Balancing Authority shall implement Confirmed Interchange exactly as agreed upon in the interchange confirmation process.	The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange with involved Interchange Authorities. a. Evidence shall demonstrate that the Interchange was implemented in the Balancing Authority's area control error equation, or the system that calculates the area control error equation. Evidence may be on a net basis or an individual interchange basis.	Included
The IA shall confirm the approvals from all involved parties (RAs, BAs, TSPs) and shall	**402 — Interchange Confirmation** ~~1.1.~~The Interchange Authority shall verify that Arranged Interchange is	For each Arranged Interchange transitioned to Confirmed Interchange, the Interchange Authority shall show evidence that it has	Included in the measure for this requirement

SAR Requirement	Standard Requirement	Standard Measurement	Comment
authorize, upon confirming approvals, the implementation of Interchange Schedules.	balanced and~~,~~ valid prior to transitioning Arranged Interchange to Confirmed Interchange.	verified that: – Source MW= sink MW (plus losses, if appropriate) – Interchange is implemented by the source Balancing Authority and the sink Balancing Authority – There is a contiguous transmission arrangement across Transmission Service Providers from the source to the sink Balancing Authorities – MW magnitude is defined – Ramp start and stop times are defined – Interchange duration is defined – Each Reliability Authority, Balancing Authority, and Transmission Service Provider has provided approval	
The IA shall confirm that Interchange Transactions are balanced and valid prior to physical delivery.	**402 — Interchange Confirmation** ~~1.1.~~The Interchange Authority shall verify that Arranged Interchange is balanced and~~,~~ valid prior to transitioning Arranged Interchange to Confirmed Interchange.	For each Arranged Interchange transitioned to Confirmed Interchange, the Interchange Authority shall show evidence that it has verified that: – Source MW= sink MW (plus losses, if appropriate) – Interchange is implemented by the source Balancing Authority and the sink Balancing Authority – There is a contiguous transmission arrangement across Transmission Service Providers from the source to the sink Balancing Authorities – MW magnitude is defined – Ramp start and stop times are defined	Included

SAR Requirement	Standard Requirement	Standard Measurement	Comment
		– Interchange duration is defined – Each Reliability Authority, Balancing Authority, and Transmission Service Provider has provided approval	
The IA shall communicate implementation status to all parties (with which the Interchange Transaction must be coordinated).	**404 — Interchange Authority Disseminates Confirmation** The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to Confirmed Interchange to all parties involved in the Interchange.	For each Arranged Interchange, the Interchange Authority shall provide evidence that it has communicated the appropriate final status to all parties involved in the interchange.	Included
The RA shall receive and confirm Interchange Transaction information with the IA.	**403 — Response to Interchange Authority** The Reliability Authority, Balancing Authority, and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. Approval is an acknowledgement by these entities that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.	The Reliability Authority, Balancing Authority, and Transmission Service Provider must provide evidence that they responded to each request from an Interchange Authority.	Included
The RA shall approve or deny the request from the IA based on reliability perspectives.	**403 — Response to Interchange Authority** The Reliability Authority, Balancing Authority, and Transmission Service Provider shall respond to a request	The Reliability Authority, Balancing Authority, and Transmission Service Provider must provide evidence that they responded to each request from an Interchange Authority.	Included

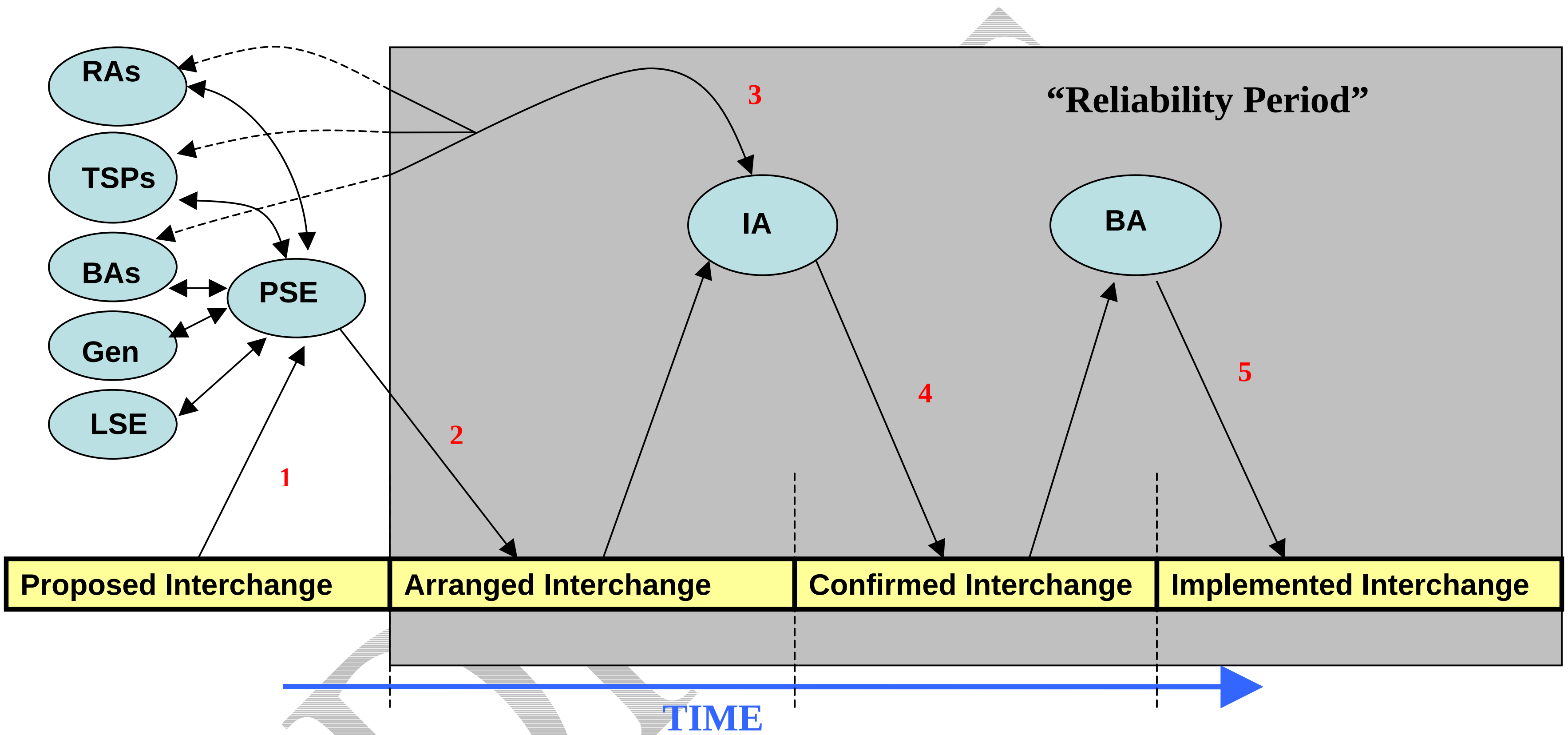
SAR Requirement	Standard Requirement	Standard Measurement	Comment
	from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. Approval is an acknowledgement by these entities that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.		
TSP shall receive and confirm Interchange Transaction information with the IA.	**403 — Response to Interchange Authority** The Reliability Authority, Balancing Authority, and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. Approval is an acknowledgement by these entities that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.	The Reliability Authority, Balancing Authority, and Transmission Service Provider must provide evidence that they responded to each request from an Interchange Authority.	Included
The TSP shall approve or deny the request from the IA.	**403 — Response to Interchange Authority** The Reliability Authority, Balancing Authority, and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange. Approval is an acknowledgement by these entities that the Arranged	The Reliability Authority, Balancing Authority, and Transmission Service Provider must provide evidence that they responded to each request from an Interchange Authority.	Included

SAR Requirement	Standard Requirement	Standard Measurement	Comment
	Interchange is acceptable and reliable with respect to their functional responsibilities.		
When an entity desires to transfer energy, the entity initiating the transaction shall submit, as a minimum, the following reliability-related transaction data to its IA: - Desire to transfer energy - Megawatt magnitude - Ramp start and stop times - Interchange transaction's duration - Sufficient information for all approval entities	**402 — Interchange Confirmation** ~~1.1.~~The Interchange Authority shall verify that Arranged Interchange is balanced and~~,~~ valid prior to transitioning Arranged Interchange to Confirmed Interchange.	For each Arranged Interchange transitioned to Confirmed Interchange, the Interchange Authority shall show evidence that it has verified that: – Source MW= sink MW (plus losses, if appropriate) – Interchange is implemented by the source Balancing Authority and the sink Balancing Authority – There is a contiguous transmission arrangement across Transmission Service Providers from the source to the sink Balancing Authorities – MW magnitude is defined – Ramp start and stop times are defined – Interchange duration is defined – Each Reliability Authority, Balancing Authority, and Transmission Service Provider has provided approval	Included in the measure for this requirement (note the standard does not address what should be submitted but it is included by default because these items are in the measure for requirement 402).
The PSE shall request approval for interchange transactions from the IA.	Not Included		This requirement is redundant to the requirement to submit the data.
The PSE shall confirm interchange transaction			Communication between the PSE and the IA is

SAR Requirement	Standard Requirement	Standard Measurement	Comment
requirements with the IA.			addressed in Standard Requirement 404.

Figure 1

APPENDIX B — Life Cycle Stages of Interchange



Data Flow:

1. PSE receives request for Proposed Interchange
2. After receiving all required business agreement, PSE communicates Arranged Interchange
3. IA requests and receives approvals in order to perform required validation
4. Upon validation, IA creates Confirmed Interchange and communicates
5. BA's create Implemented Interchange with entry into ACE equation

Appendix C —Functional Model Technical Document — Losses

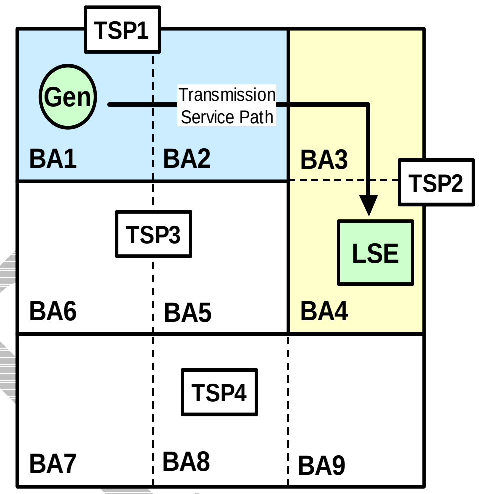


Figure 1 – The portion of the losses caused by the Transaction from the Generator in BA1 to the Load-Serving Entity in BA4 appear as a load change in all the Balancing Authorities 1–9.

Compensation for Losses. Before delving into how the Reliability Model handles compensation for losses, we need to review two physical properties of losses (see Figure 4):

1. **Losses occur when power flows over the transmission system, and these losses are simply part of the load within the Balancing Authority's area**. The Balancing Authority cannot tell what part of its load is due to losses and what part is due to customers' toasters and air-conditioners because load isn't metered. Only generation and tie-lines are metered.
2. **Losses due to Transactions are not confined to the Balancing Authorities along the transmission service path**. In Figure 4, the incremental losses caused by the Transaction from the Generator in BA1 to the Load-Serving Entity in BA4 appears as a load change in all the Balancing Authorities 1–9.

Because losses are part of the Balancing Authority's load, there must be compensation for serving that part of the load. We now need to review two fundamental assumptions regarding how losses are compensated:

1. **Loss compensation is only provided to the Balancing Authorities via their Transmission Service Providers who are providing the transmission service path**. In Figure 4, only BA1, 2, 3, and 4 are compensated through TSP1 and TSP2[1].
2. **Loss compensation may be in dollars (financial payment) or energy ("self-provision")**. This depends on the requirements in the Transmission Service Providers' tariffs.

We now turn our discussion to the details of loss compensation.

Financial Compensation. The Purchasing-Selling Entity may compensate the Transmission Service Providers by monetary payment according to the transmission tariffs. The Transmission Service Providers, in turn, pass these payments to their Balancing Authorities who reimburse those Generators providing load-following service.

The financial loss compensation is shown in Figure 5. In this case, the total energy contracted for (100 MW) is delivered from the Generator in BA1 to the Load-Serving Entity in BA4, and the Purchasing-Selling Entity reimburses TSP1 and TSP2 according to their tariffs.

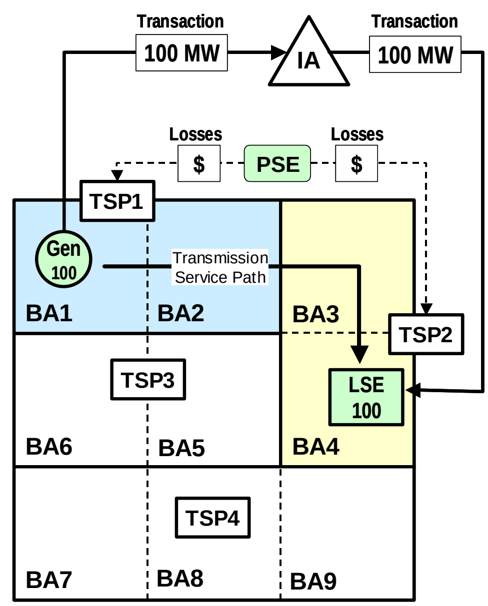


Figure 2 – The PSE may compensate the TSPs with monetary payment.

[1] This example assumes a "contract path." A regional transmission arrangement might compensate Balancing Authorities who are parties to the arrangement on a flow basis.

"Self-provision" Compensation. If the Transmission Service Provider's tariff allows, the Purchasing-Selling Entity may supply the energy losses himself as MW. This can be done two different ways:

Today, the most common way of self-provision involves the Purchasing-Selling Entity purchasing the Transaction energy plus losses energy from the Generator, and "dropping off" the losses along the transmission scheduling path as shown in Figure 6. Traditionally, this has been done between adjacent Control Areas, with each Control Area's net interchange equal to its loss compensation. This compensation is determined by the Transmission Provider's tariff. In the figure on the right, the Purchasing-Selling Entity has purchased 107 MW from the Generator in CA1, and has "dropped off" a total of 7 MW of losses within each Control Area along the scheduling path so that 100 MW arrives at the point of delivery to the Load-Serving Entity. The numbers in the white circle indicates the MW loss compensation.

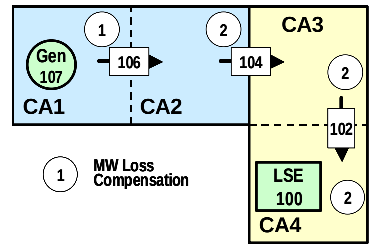


Figure 3 – Present practice for self-provision of losses.

The Task Force proposes a change in this method under the Reliability Model. As we explained above in the "Interchange" subsection, "intermediary" Balancing Authorities are not parties to Interchange Transactions between the source and sink Balancing Authorities. Therefore, self-provided losses cannot be simply "dropped" along the way by decrementing the Interchange Schedules from BA to BA. Instead, the Interchange Authority will serve as the loss distributor by setting up individual Transactions with the "intermediary" Balancing Authorities on behalf of the Purchasing-Selling Entity as shown in Figure 7. The Purchasing-Selling Entity notifies the Transmission Service Provider(s) of this loss compensation arrangement. The TSP, in turn, confirms the loss compensation arrangement with the IA when the IA approaches the TSP to confirm the transmission arrangements.

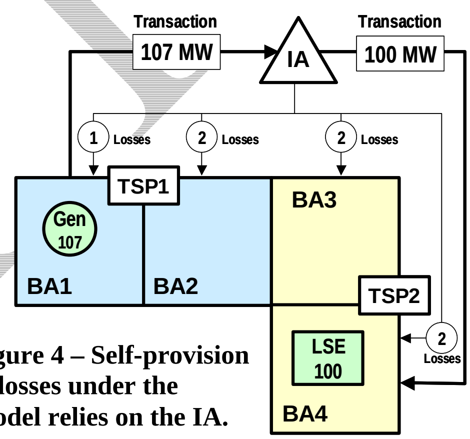


Figure 4 – Self-provision of losses under the Model relies on the IA.

Balancing Authority	*Actual from Tie Meters*	*Schedule(s) with IA*
BA1	+106 to BA2 **NET = +106**	+107 to IA -1 from IA for losses **NET = +106**
BA2	-106 from BA1 +104 to BA3 **NET = -2**	-2 from IA for losses **NET = -2**
BA3	-104 from BA2 +102 to BA4 **NET = -2**	-2 from IA for losses **NET = -2**
BA4	-102 from BA3 **NET = -102**	-100 from IA -2 from IA for losses **NET = -102**

The table above explains the resulting actual and scheduled interchange between the Balancing Authorities and the Interchange Authority.

The Purchasing-Selling Entity could also supply these losses from another Generator via separate Transactions.

These definitions will be posted and balloted along with the standard, but will not be restated in the standard. Instead, they will be included in a separate "Definitions" section containing definitions relevant to all standards that NERC develops.

Version 1

Definitions

Interchange: Energy transfers that cross Balancing Authority boundaries.

Arranged Interchange: The state where all arrangements necessary to submit the Interchange request to the Interchange Authority have been made.

Confirmed Interchange: The state where the Interchange Authority has verified the Arranged Interchange and is ready to submit it to the Balancing Authorities.

Implemented Interchange: The state where the Balancing Authority enters the Confirmed Interchange into its area control error equation.

400 — COORDINATE INTERCHANGE

Purpose: To ensure that the implementation of Interchange between source and sink Balancing Authorities is coordinated by an Interchange Authority such that the following reliability objectives are met:

(1) Each Interchange is checked for reliability before it is implemented.

(2) The Balancing Authorities implement the Interchange exactly as agreed upon in the Interchange confirmation process.

(3) Interchange information is available for reliability assessments.

Effective Period: This standard will become effective upon the date of NERC Board of Trustees adoption.

Applicability: This standard applies to entities performing various electric system functions, as defined in the most recent version of the North American Electric Reliability Council Functional Model. NERC is now developing standards and procedures for the identification and certification of such entities. Until that identification and certification is complete, these standards apply to the existing entities (such as control areas, transmission owners and operators, and generation owners and operators) that are currently performing the defined functions.

Clarifying documents: For more information see the North American Electric Reliability Council Functional Model and the Coordinate Interchange Standard Reference Document.

In this standard, the terms *Balancing Authority*, *Interchange Authority*, *Reliability Authority*, *Purchasing/Selling Entity, and Transmission Service Provider* refer to the entities performing these functions as defined in the Functional Model.

401 Implementation of Interchange

(a) Requirement

(1) The Balancing Authority shall implement Confirmed Interchange exactly as agreed upon in the Interchange confirmation process.

(b) Measures

(1) The Balancing Authority shall provide evidence that Implemented Interchange matches Confirmed Interchange as submitted by the Interchange Authority.

(i) Evidence shall demonstrate that the Interchange was implemented in the Balancing Authority's area control error equation, or the system that calculates the area control error equation. Evidence may be on a net basis or an individual Interchange basis.

(ii) Balancing Authorities that are interconnected with a DC tie shall demonstrate that the Interchange was implemented in the area control area equation or modeled as an equivalent generator / load within its area.

(c) Regional Differences

(1) This requirement does not apply in the ERCOT Region because ERCOT operates as a single Balancing Authority, asynchronous to the Eastern and Western Interconnections. This difference shall be applied on an Interconnection-wide basis in ERCOT.

(d) Compliance Monitoring Process

(1) Each Balancing Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

(2) Subsequent to the initial compliance review, compliance will be:

(i) Verified by audit at least once every three years.

(ii) Verified by spot checks in years between audits.

(iii) Verified by annual audits of noncompliant Balancing Authorities, until compliance is demonstrated.

(iv) Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

(3) The Performance-reset Period shall be twelve months from the last noncompliance to requirement 401(a). Balancing Authorities found noncompliant shall keep data until deficiencies resulting in noncompliance are resolved.

(4) The Balancing Authorities shall make the following available for inspection by the Compliance Monitor upon request:

(i) Rolling three months worth of Balancing Authorities' Implemented Interchange values as submitted to them by the Interchange Authorities.

(ii) Indication of whether Interchange data is block or ramp schedule.

(5) The Compliance Monitor shall verify Balancing Authority data by comparing it to corresponding Interchange Authority data.

(e) Levels of Noncompliance

(1) Level one: 90 to 99% of the records confirm that Implemented Interchange matches corresponding Interchange Authority Interchange.

(2) Level two: 80 to 89% of the records confirm that Implemented Interchange matches corresponding Interchange Authority Interchange.

(3) Level three: Less than 80% of the records confirm that Implemented Interchange matches corresponding Interchange Authority Interchange.

(4) Level four: No records available to review.

(f) Sanctions

(1) Sanctions for noncompliance shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this standard for reference). In cases where financial penalties are assigned for noncompliance, these penalties shall be the fixed dollar sanctions listed in the matrix, not the per MW sanctions.

402 Interchange Confirmation

(a) Requirement

(1) The Interchange Authority shall verify that Arranged Interchange is balanced and valid prior to transitioning Arranged Interchange to Confirmed Interchange.

(b) Measures

(1) For each Arranged Interchange transitioned to Confirmed Interchange, the Interchange Authority shall show evidence that it has verified that:

(i) Source MW= sink MW (plus losses, if appropriate)

(ii) Interchange is between a source Balancing Authority and a sink Balancing Authority

(iii) There is a contiguous transmission arrangement across Transmission Service Providers from the source to the sink Balancing Authorities

(iv) MW magnitude is defined

(v) Ramp start and stop times are defined

(vi) Interchange duration is defined

(vii) Each Reliability Authority, Balancing Authority, and Transmission Service Provider has provided approval.

vii(1) For a reliability related change requested by a Reliability Authority, no other entity approvals are required.

(c) Regional Differences

(1) This requirement does not apply in the ERCOT Region because ERCOT operates as a single Balancing Authority, asynchronous to the Eastern and Western Interconnections. This difference shall be applied on an Interconnection-wide basis in ERCOT.

(d) Compliance Monitoring Process

(1) Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

(2) Subsequent to the initial compliance review, compliance will be:

(i) Verified by audit at least once every three years.

(ii) Verified by spot checks in years between audits.

(iii) Verified by annual audits of noncompliant Interchange Authorities, until compliance is demonstrated.

(iv) Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

(3) The performance-reset period shall be twelve months from the last noncompliance to 402(a). Interchange Authorities found noncompliant shall keep data until deficiencies resulting in noncompliance are resolved.

(4) Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

(i) Rolling three months worth of Interchange-related data, as listed in 402(b)(1).

(5) The Compliance Monitor shall verify Interchange Authority data by comparing it to corresponding Balancing and Reliability Authority, Purchasing/Selling Entity, and Transmission Service Provider data.

(e) Levels of Noncompliance

(1) Level one: 90 to 99% of the Interchange-related data includes all items listed in 402(b)(1).

(2) Level two: 80 to 89% of the Interchange-related data includes all items listed in 402(b)(1).

(3) Level three: Less than 80% of the Interchange-related data includes all items listed in 402(b)(1).

(4) Level four: No records available to review.

(f) Sanctions

(1) Sanctions for noncompliance shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this standard for reference). In cases where financial penalties are assigned for noncompliance, these penalties shall be the fixed dollar sanctions listed in the matrix, not the per MW sanctions.

403 Response to Interchange Authority

(a) Requirement

(1) The Reliability Authority, Balancing Authority and Transmission Service Provider shall respond to a request from an Interchange Authority to transition an Arranged Interchange to a Confirmed Interchange by acknowledging that the Arranged Interchange is acceptable and reliable with respect to their functional responsibilities.

(b) Measures

(1) The Reliability Authority, Balancing Authority, and Transmission Service Provider shall provide evidence that they responded to each request from an Interchange Authority.

(c) Regional Differences

(1) This requirement does not apply in the ERCOT Region because ERCOT operates as a single Balancing Authority, asynchronous to the Eastern and Western Interconnections. This difference shall be applied on an Interconnection-wide basis in ERCOT.

(d) Compliance Monitoring Process

(1) The responsible entity shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

(2) Subsequent to the initial compliance review, compliance will be:

(i) Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. Complaints will be evaluated by the Compliance Monitor.

(3) The Performance-reset Period shall be twelve months from the last noncompliance to 403(a). Responsible entities found noncompliant shall keep data until deficiencies resulting in noncompliance are resolved. The responsible entity shall make the following available for inspection by the Compliance Monitor upon request:

(i) Rolling three months worth of hourly Interchange records that indicate that each Interchange Authority request was responded to.

(4) The Compliance Monitor shall verify Balancing Authority Reliability Authority, Purchasing/Selling Entity, and Transmission Service Provider data by comparing it to corresponding Interchange Authority data.

(e) Levels of Noncompliance

(1) Level one: Not specified

(2) Level two: Not specified

(3) Level three: Not specified

(4) Level four: Evidence not available or not provided.

(f) Sanctions

(1) Sanctions for noncompliance shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this standard for reference). In cases

where financial penalties are assigned for noncompliance, these penalties shall be the fixed dollar sanctions listed in the matrix, not the per MW sanctions.

404 Interchange Authority Disseminates Confirmation

(a) Requirement

(1) The Interchange Authority shall communicate whether the Arranged Interchange has transitioned to a Confirmed Interchange to all entities involved in the Interchange.

(b) Measures

(1) For each Arranged Interchange, the Interchange Authority shall provide evidence that it has communicated the appropriate final status to all entities involved in the Interchange.

(2) For each Arranged Interchange that includes a DC tie, the Interchange Authority shall provide evidence that it has communicated the appropriate final status to the Balancing Authorities on both sides of the DC tie, even if the Balancing Authorities are neither the source or sink for the Interchange.

(c) Regional Differences

(1) This requirement does not apply in the ERCOT Region because ERCOT operates as a single Balancing Authority, asynchronous to the Eastern and Western Interconnections. This difference shall be applied on an Interconnection-wide basis in ERCOT.

(d) Compliance Monitoring Process

(1) Each Interchange Authority shall demonstrate compliance to the Compliance Monitor within the first year that this standard becomes effective or the first year the entity commences operation by self-certification to the Compliance Monitor.

(2) Subsequent to the initial compliance review, compliance will be:

> (i) Verified at any time as the result of a complaint. Complaints must be lodged within 60 days of the incident. The Compliance Monitor will evaluate complaints.

(3) The performance-reset period shall be twelve months from the last noncompliance to 404(a). Interchange Authorities found noncompliant shall keep data until deficiencies resulting in noncompliance are resolved. Each Interchange Authority shall make the following available for inspection by the Compliance Monitor upon request:

> (i) Rolling three months worth of hourly Interchange records that indicate that each Interchange Authority request was responded to.

(4) The Compliance Monitor shall verify Interchange Authority data by comparing it to corresponding Balancing Authority, Reliability Authority, Purchasing/Selling Entity, and Transmission Service Provider data.

(e) Levels of Noncompliance

(1) Level one: Not specified

(2) Level two: Not specified

(3) Level three: Not specified

(4) Level four: Evidence not available or not provided.

(f) Sanctions

(1) Sanctions for noncompliance shall be applied consistent with the NERC compliance and enforcement matrix (attached to the end of this standard for reference). In cases where financial penalties are assigned for noncompliance, these penalties shall be the fixed dollar sanctions listed in the matrix, not the per MW sanctions.

Sanctions Table

The following table is an approved table of Compliance Sanctions. This table of sanctions was developed by the Compliance Subcommittee as part of the NERC Compliance Enforcement Program and was approved by the NERC Board of Trustees. The enforcement matrix is divided into four levels of increasing noncompliance vertically and the number of violations in a defined period at a given level horizontally. In the enforcement matrix, note that there are three sanctions that can be used: a letter, a fixed fine, and a $$ per MW fine.

Letter

The letter is a sanction used to notify company executives, Regional officers, and regulators when an entity is noncompliant. The distribution of the letter varies depending on the severity of the noncompliance. It is used first to bring noncompliance the attention of those who can take action to brig the entity into compliance.

- Letter (A) — Letter to the entity's vice president level or equivalent informing the entity of noncompliance, with copies to the data reporting contact, and the entity's highest ranking Regional Council representative.
- Letter (B) — Letter to the entity's chief executive officer or equivalent, with copies to the data reporting contact, the entity's highest ranking Regional Council representative, and the vice president over the area in which noncompliance occurred.
- Letter (C) — Letter to the entity's chief executive officer and chairman of the board, with copies to the NERC president, regulatory authorities having jurisdiction over the noncompliant entity if requested by such regulatory authorities, the data reporting contact, the entity's highest ranking Regional Council representative, and the vice president over the area in which noncompliance occurred.

Fixed Dollars

This sanction is used when a letter is not enough and a stronger message is desired. Fixed dollars are typically assigned as a one-time fine that is ideal for measures involving planning-related standards. Many planning actions use forward-looking assumptions. If those assumptions prove wrong in the future, yet they are made in good faith using good practices, entities should not be harshly penalized for the outcome.

Dollars per MW

Dollars per MW sanctions are oriented toward operationally based standards. The MW can be load, generation, or flow on a line. Reasonableness of a sanction needs to be figured into assessing $/MW penalties. Assessing large financial penalties is not the goal, but sending a message with proper emphasis on $$$ can be controlled with the multiplier.

Occurrence Period Category	Number of Violations in Occurrence Period at a Given Level			
1st Period of Violations (Fully Compliant Last Period)	1	2	3	4 or more
2nd Consecutive Period of Violations		1	2	3 or more
		$ Sanction from Table; Letter (C) only if Letter (B) previously sent		
3rd Consecutive Period of Violations			1	2 or more
			$ Sanction from Table; Letter (C) only if Letter (B) previously sent	
4th or greater Consecutive Period of Violations				1
				$ Sanction from Table; Letter (C)

Level of Noncompliance	Sanctions Associated With Noncompliance			
Level 1	Letter (A)	Letter (A)	Letter (B) and $1,000 or $1 Per MW	Letter (B) and $2,000 or $2 Per MW
Level 2	Letter (A)	Letter (B) and $1,000 or $1 Per MW	Letter (B) and $2,000 or $2 Per MW	Letter (B) and $4,000 or $4 Per MW
Level 3	Letter (B) and $1,000 or $1 Per MW	Letter (B) and $2,000 or $2 Per MW	Letter (B) and $4,000 or $4 Per MW	Letter (B) and $6,000 or $6 Per MW
Level 4	Letter (B) and $2,000 or $2 Per MW	Letter (B) and $4,000 or $4 Per MW	Letter (B) and $6,000 or $6 Per MW	Letter (B) and $10,000 or $10 Per MW

Interpreting the Tables:

- These tables address penalties for violations of the same measure occurring in consecutive compliance reporting periods.
- If a participant has noncompliant performance in consecutive compliance reporting periods, the sanctions applied are more punitive.