



NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

NERC-NAESB-ISO/RTO Council Joint Interface Committee

July 21, 2005 (1–5 p.m. EDT)
July 22, 2005 (8 a.m.–noon EDT)

Meeting Location	Dial-In Information
NPCC Offices 1515 Broadway (43rd Floor) (between 44th and 45th streets) New York, New York Telephone: 212-840-1070	Telephone: 732-694-2061 Pass Code July 21: 11300721 Pass Code July 22: 11300722 Facilitator: Gerry Cauley

Meeting Agenda

1. Administrative Items

- a. Introductions
- b. Roster and Membership Changes
- c. Establish Quorum
- d. Antitrust Guidelines
- e. Prior Meeting Minutes
- f. Agenda

2. Proposed Business Practice Standards

- a. R05004 TTC/ATC/AFC and CBM/TRM in Requesting and Scheduling Transmission Service
- b. R05007 Remove References to ERCOT from Version 0 Business Practice Standards
- c. R05018 PSE Optional Approval Rights for E-Tag Transmission Segment

3. Proposed Reliability Standards

- a. Nuclear Plant Offsite Power Reliability

4. Other Business

- a. Status of Functional Model and Regional Reliability Plans
- b. Future Meetings and Conference Calls
- c. Other Business

5. Special Agenda Item: Review of JIC Process

Adjourn

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Background for Agenda Item 1 – Administrative Items

Item 1a: Introductions — Co-Chairs Deselle, Campbell, and Tammar will lead the introduction of JIC members and guests.

Item 1b: Roster and Membership Changes — The current JIC roster is provided as **Attachment 1**. Secretary Cauley will review membership changes since the last meeting:

- NERC: Mike Penstone — Hydro One replaces Ed Tymofichuk — Manitoba Hydro.
- IRC: Karl Phirrmann — PJM replaces Audrey Zibelman — PJM.
- IRC: Ed Riley — CAISO resigned JIC, replacement TBD.

Item 1c: Establish Quorum — Secretary Cauley will determine the presence of a quorum for each party to the MOU.

Item 1d: Antitrust Guidelines — NAESB staff will review the Antitrust Guidelines.

Item 1e: Prior Meeting Minutes — Secretary Cauley will present the draft minutes of the January 18, 2005 meeting and the April 29, 2005 conference call for approval (**Attachments 2 and 3**).

Item 1f: Agenda — Co-chair Michael Deselle will review the meeting agenda and objectives.

Background for Agenda Item 2 — Proposed Business Practice Standards

Item 2a: R05004 TTC/ATC/AFC and CBM/TRM in Requesting and Scheduling Transmission Service — The proposal is to develop a business practice standard for the use of TTC/ATC/AFC and CBM/TRM in requesting and scheduling transmission service. The request was submitted by the NERC Long-Term ATC/AFC Task Force (LTATF). See **Attachments 4 and 5**. Two related SARs (**Attachments 6 and 7**) were submitted to NERC as proposed reliability standards. The SARs are currently posted for stakeholder comment and may be presented to the JIC for assignment once it is determined there is stakeholder consensus on the reliability need and scope of the proposed standards. This work by NAESB and NERC is related to a current FERC Notice of Inquiry (**Attachment 8**).

Item 2b: R05007 Remove References to ERCOT from Version 0 Business Practice Standards — The proposal is to review the NAESB WEQ "Version 0" business practice standards and remove any references to ERCOT. The request was submitted by the Electric Reliability Council of Texas (ERCOT). See **Attachment 9**.

Item 2c: R05018 PSE Optional Approval Rights for E-Tag Transmission Segment — The proposal is to revise the E-Tag specification document to allow PSEs associated with a transmission segment in the tag optional approval rights. The request was submitted by the Joint NERC-NAESB Interchange Scheduling Work Group. This item is on the July 8, 2005 triage agenda and will likely be assigned to the WEQ. See **Attachment 10**.

Background for Agenda Item 3 — Proposed Reliability Standards

Item 3a Nuclear Plant Offsite Power Reliability — The SAR (**Attachment 11**) proposing a standard on Nuclear Plant Offsite Power Reliability was posted for two rounds of stakeholder comments. There was support in the comments of the reliability need for the proposed standard. Minority views, which the SAC felt were adequately addressed by the drafting team, were: a) the requirements for reliable offsite power to nuclear plants can be addressed in agreements, and b) there may be a shifting of responsibilities or costs from the nuclear plant to the transmission owner/operator. The requester is the Nuclear Energy Institute Grid Reliability Task Force.

The request was sparked in part by an initiative of the Nuclear Regulatory Commission inquiring how to ensure grid reliability is sufficient to meet nuclear safety licensing requirements.

Background for Agenda Item 4 — Other Business

Item 4a Status of Functional Model and Regional Reliability Plans — Linda Campbell will review the status of the work of the Functional Model Working Group regarding revisions to the functional model and a guide for regional reliability plans. She will also review actions by the Standards Authorization Committee to direct drafting teams to develop standards based on the Reliability Coordinator in lieu of the Reliability Authority.

Item 4b Future Meetings and Conference Calls — The JIC is requested to schedule its next meeting date and suggest possible agenda items. The JIC is requested to schedule meeting dates for the remainder of 2005.

Item 4c Other Business — JIC members are requested to present any additional business for consideration of the JIC.

Background for Special Agenda Item: Review of JIC Process

The JIC is requested to review the JIC process and performance since the updated Memorandum of Understanding (**Attachment 12**) became effective on May 15, 2003. The MOU calls for an annual review stating:

The Parties agree to meet annually during the anniversary month of the signing of this MOU to evaluate in good faith the effectiveness and efficiency of this MOU in meeting the goal of coordinating the standards and policy development-related activities of the three organizations and to make any appropriate revisions.

Several issues are presented here to frame the discussion. The list is not intended to be exhaustive and members of the JIC are invited to raise other issues of importance to the group.

1. Has the JIC been successful in achieving its mission of assigning standards "to avoid overlap and duplication of effort in the activities of the three organizations"? What can be done to improve that performance?
2. Are standards requests presented to the JIC with sufficient completeness and clarity to understand the scope of the proposed standard and where it should be assigned? If not, what can be done to improve the completeness and clarity of requests?
3. Has the JIC been able to establish a basis, through experiential precedence, for determining which proposed standards should be reliability standards, business practice standards, and ISO/RTO market protocols? Is the distinction between reliability, business practice, and ISO/RTO protocol sufficiently clear for the JIC to be effective?
4. Has the JIC been successful in not overstepping its authority by basing its decisions on the technical merits or need for a proposed standard, which are issues to be addressed within the respective standards processes?
5. Is there an issue if the scope of a proposed standard changes in development after the request has been assigned by the JIC ('standard scope creep')? Has this been the case? Should changes in scope be subject to review by the JIC?
6. Has the assignment of standards requests allowed NERC to retain a 'complete set' of reliability standards to be used in its compliance program? Is achieving the 'complete set' necessary for reliability an issue?

7. Has the JIC been effective in coordinating annual work plans of the three parties?
8. Are there any revisions to the MOU that would be necessary and appropriate based on JIC performance and results over the past two years?

Adjourn

July 8, 2005

Joint Interface Committee (NERC-NAESB)

Co-Chair NERC	Linda Campbell Director of Reliability	Florida Reliability Coordinating Council 1408 N. Westshore Boulevard Suite 1002 Tampa, Florida 33607-4512	(813) 289-5644 (813) 289-5646 Fx lcampbell@ frcc.com
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Co-Chair IRC	Karl Tammar Administrator of Industry Affairs	New York Independent System Operator 3890 Carman Road Schenectady, New York 12303	(518) 356-6205 (518) 356-6118 Fx ktammar@ nyiso.com
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IRC Representative	TBD	California ISO 151 Blue Ravine Road Folsom, California 95630	(916) 351-2123 (916) 351-2350 Fx
NAESB Alternate	Andy Dotterweich General Supervisor-Federal Regulatory Affairs	Consumers Energy Co. 212 W. Michigan Avenue Jackson, Michigan 49281	(517) 788-0495 acdotterweich@ cmsenergy.com
NERC Representative	Mark E. Fidrych Power Operations Specialist	Western Area Power Administration MC J0003 P.O. Box 3700 Loveland, Colorado 80539-3003	(970) 461-7240 (970) 461-7299 Fx fidrych@wapa.gov
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NERC Representative	Sam R. Jones Chief Operating Officer	Electric Reliability Council of Texas, Inc. 2705 West Lake Drive Taylor, Texas 76574-2136	(512) 248-3177 (512) 248-3095 Fx sjones@ercot.com
IRC Representative	Bill Limbrick	IMO Station A Box 4474 Toronto, Ontario M5W 4E5	(905) 855-6293 (905) 855-6471 Fx bill.limbrick@ ieso.ca
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NAESB Representative	Lou Oberski Director, Electric Market Policy	Dominion Resources Services, Inc. 120 Tredegar Street P.O. Box 25615 Richmond, Virginia 23219	(804) 787-5714 (804) 787-6473 Fx lou_oberski@ dom.com
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IRC Representative	Karl Pfirrmann	PJM 800 Cabin Hill Drive Greensburg, PA 15601	(610) 666-3126 (724) 832-6528 Fx pfirrk@pjm.com
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NAESB Alternate	Thomas Ringenbach Manager, Business Standards	American Electric Power 1 Riverside Plaza 13th Floor Columbus, Ohio 43215	(614) 223-2679 tjrigenback@ aep.com
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IRC Alternate	Stephen G. Whitley Vice President, System Operations	ISO New England, Inc. One Sullivan Road Holyoke, Massachusetts 01040-2841	(413) 535-4361 (413) 535-4050 Fx swhitley@ iso-ne.com
NAESB Alternate	Walter L. Yeager Managing Director, Market Development	Cinergy Services Inc. 139 East Fourth Street Cincinnati, Ohio 45202	(513) 419-5711 (513) 419-5511 Fx wyeager@ cinergy.com
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Secretary	Gerry W. Cauley Director - Standards	North American Electric Reliability Council 116-390 Village Boulevard Princeton, New Jersey 08540-5731	(609) 452-8060 (609) 452-9550 Fx gerry.cauley@ nerc.net



NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

NERC — NAESB — ISO/RTO Council

Joint Interface Committee

January 18, 2005
FRCC Offices
Tampa, Florida

Minutes

Attendance

NERC Members/Alternates	IRC Members/Alternates
Linda Campbell, FRCC (JIC Co-Chairman)	Karl Tammar, NYISO (JIC Co-Chairman)
Mark Fidrych, WAPA [Phone]	Bill Limbrick, IESO [Phone]
Scott Henry, Duke Power	Ed Riley, California ISO [Phone]
Sam Jones, ERCOT [Phone]	Charles Yeung, SPP
Ed Schwerdt, NPCC	
Ed Tymofichuk, Manitoba Hydro [Phone]	Observers
Gerry Cauley, NERC (Secretary)	Bruce Balmat, MAAC [Phone]
	Christopher Burden, Williams Gas [Phone]
NAESB Members/Alternates	Roman Carter, Southern Company
Michael Desselle, AEP (JIC Co-Chairman)	Dale Davis, Williams Gas [Phone]
Syd Berwager, Bonneville Power [Phone]	Al DiCaprio, PJM [Phone]
Ed Davis, Entergy [Phone, non-voting]	Joel Dison, Southern Company [Phone]
Andy Dotterweich, Consumers [Phone, non-voting]	Ollie Frazier, Duke Energy [Phone]
Barry Green, Ontario Power Gen. [Phone]	Dowell Hudson, MISO
Lou Oberski, Dominion Resources	DeDe Kirby, NAESB [Phone]
Mary Ellen Paravalos	Rae McQuade, NAESB
Jim Templeton [Phone]	Lorne Midford, Manitoba Hydro [Phone]
Walt Yeager, Cinergy	John Mosier, NPCC [Phone]
	Veronica Tomason, NAESB [Phone]
	Kathy York, TVA [Phone]

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Call to Order

Chairman Desselle called the meeting to order.

Quorum

Secretary Cauley announced that each party had reached a quorum.

Antitrust Guidelines

Dede Kirby reviewed the antitrust guidelines.

Prior Meeting Minutes

On a motion by Scott Henry, the JIC approved the September 21–22, 2004 meeting minutes without objection.

Agenda

Chairman Desselle reviewed the meeting agenda, which is provided as **Exhibit A**. The agenda was adopted, with the addition of a discussion item on a joint NERC-NAESB operating manual.

Electric Market Timelines (R04020)

Kathy York presented a proposal to standardize Electric Market Timelines (Attachments 3 and 4 in the agenda package). Kathy clarified that this request focuses on the day-ahead trading horizon, including arrangements for transmission and energy trading. It was noted that this request is related to Seams Issues 79 and 106.

The JIC agreed that the Scoping Document provided a more complete and focused description of the proposed business practice than the request itself. The Scoping Document did not include ramping and the JIC agreed ramping should not be part of the request.

Several members questioned whether the request was duplicative of other projects, such as energy day, OASIS business practices, or interchange scheduling. NAESB representatives indicated this work is not duplicative of those projects. This project is focused on coordinating tariff and market timelines among RTOs, and between RTO and non-RTO entities.

There was also a concern expressed that the proposed standard was addressing an issue among several entities and could possibly be more appropriately addressed in an agreement. Others noted that whether or not the need for the standard is justified should be addressed in the appropriate (NERC or NAESB) standards forum, and not by the JIC.

The JIC unanimously approved a motion by Syd Berwager to assign Request R04020 "Electric Market Timelines" to NAESB for development, on the assumption that the scope will be as defined in the Scoping Document. A roll call vote was conducted as follows:

NERC
Linda Campbell — Yes
Scott Henry — Yes
Sam Jones — Yes
Ed Schwerdt — Yes

NAESB
Michael Desselle — Yes
Syd Berwager — Yes
Barry Green — Yes
Lou Oberski — Yes
Mary Ellen Paravalos — Yes
Jim Templeton — Yes
Walt Yeager — Yes

IRC
Karl Tammar — Yes
Bill Limbrick — Yes
Ed Riley — Yes
Charles Yeung — Yes

OASIS Business Practices (R04035) and Standards of Conduct (R04036)

Joel Dison presented a proposal to revise the OASIS Business Practices (Attachments 5 and 6 in the agenda package) and to revise the OASIS Standards of Conduct (Attachment 7 in the agenda package).

The JIC approved without objection a motion by Lou Oberski to assign the development of Request R04035 "OASIS Business Practices" and Request R04036 "OASIS Standards of Conduct" to NAESB for development.

TSIN Registry (R04037)

Joel Dison presented a request for developing a standard for the TSIN Registry. The JIC was concerned that the registry is a tool maintained by NERC, and that the tool has both reliability and business practice purposes. The JIC suggested there might be a need for both a business practice standard and a reliability standard to define the functional needs for the tool. The JIC also suggested that the standard should focus on generically defining data and performance requirements necessary to meet business and reliability objectives, not on writing a tool specification as part of a standard. NAESB representatives withdrew the request and indicated the request would be remanded back to Paul Sorenson for further work.

Interchange Business Practices (R05001)

Roman Carter presented a proposal to revise the draft Interchange Business Practices (Attachment 9 in the agenda package). The JIC discussed the relationship of this proposal to other interchange standards efforts at NERC and NAESB. A concern was expressed that there was not a clear sense of the purpose defined for the requested work.

The JIC approved without objection a motion by Lou Oberski to assign Request R05001 "Interchange Business Practices" to NAESB for development, with a request that this work be closely coordinated with the NERC Coordinate Interchange Standard Drafting Team and that a clear description of the need would be developed.

Phase III-IV Planning Standards

Gerry Cauley presented four related SARs for the development of Phase III-IV Planning Standards to replace those not completed in the Version 0 standards (Attachments 10-13 in the agenda package).

The JIC approved without objection a motion by Scott Henry to assign the development of the Phase III-IV planning standards to NERC.

Review of 2005 Work Plans

Michael Desselle provided an overview the NAESB Wholesale Electric Quadrant 2005 Annual Work Plan (Attachment 14 in the agenda materials). It was noted that Item 2 on the NAESB WEQ plan, related to ATC, required coordination between NERC and NAESB. It was also noted that the previous results on Seams Issues in February 2004 still apply in this area and should be considered for any project planning going forward.

Linda Campbell reviewed the current working draft of the Standards Authorization Committee's reliability standards work plan (Attachment 15 to be provided).

Karl Tammar reviewed the status of the IRC 2005 Work Plan (**Exhibit B**).

Joint TLR Procedure Task Force

Michael Desselle reviewed the status of the work by the joint NERC-NAESB task force determining how to split the TLR procedure into reliability requirements and business practices.

Functional Model / Standards Coordination Task Force

Gerry Cauley reviewed the status of a task force formed to resolve issues arising from the adoption of the Functional Model into the Version 0 Reliability Standards (Attachments 16 and 17 in the agenda package). The JIC discussed the need to clarify the status of the Interchange Authority or Coordinator to allow interchange standards to move forward.

NERC-NAESB Coordination

The JIC discussed how best to coordinate joint standards projects, now that the Market Committee is proposing to disband. The JIC agreed to work further on this issue at the next meeting.

Joint Operating Manual

The JIC discussed the need for initiating an operating manual that is coordinated between NERC and NAESB to facilitate ease of use by operating personnel. The JIC indicated a preference for a seamless, one-stop navigation page for users that would allow each organization to maintain its own source documents.

Future Meetings and Conference Calls

The JIC tentatively set March 4, 2005 at 2 p.m. EST for its next conference call.

Adjourn

There being no further business, a motion was approved to adjourn the meeting.



NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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NERC-NAESB-ISO/RTO Council Joint Interface Committee

January 18, 2005 (9:00 a.m. to 3 p.m.)

Meeting Agenda

1. **Administrative Items**
 - a. Introductions
 - b. Roster and Quorum
 - c. Antitrust Guidelines
 - d. Prior Meeting Minutes (**Approve**)
 - e. Agenda and Objectives
2. **Proposed Business Practice Standards**
 - a. Standardize Electric Market Timelines (**Assign to NAESB**)
 - b. Revise OASIS Business Practices (**Assign to NAESB**)
 - c. Revise OASIS Standards of Conduct (**Assign to NAESB**)
 - d. Revise TSIN Registry (**Assign to NAESB**)
 - e. Revise Interchange Business Practices (**Assign to NAESB**)
3. **Proposed Reliability Standards**
 - a. Phase III-IV Planning Standards (**Assign to NERC**)
4. **Preliminary Review of 2005 Annual Plans**
 - a. NAESB 2005 Annual Plan for Wholesale Electric Quadrant
 - b. NERC Standards 2005 Work Plan
 - c. IRC 2005 Work Plan
5. **Other Business**
 - a. NERC Functional Model/Standards Coordination Task Force
 - b. Future Meetings and Conference Calls
 - c. Other Business

Adjourn

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ISO/RTO Council 2005 Annual Work Plan for Standards Development and Standardization Activities

The ISO/RTO Council (“IRC”) will participate in industry standards development efforts with NERC and NAEASB. This plan identifies the objectives and priorities for the IRC in coordinating standards development activities with NERC and NAEASB. The primary mechanism for coordinating and presenting consensus positions to the industry will be through the IRC’s Standards Review Committee (“SRC”).

Reliability Standards Development

The IRC vigorously supports reliability standards that are clear, concise, and measurable. The requirement that reliability standards be uniformly implemented and complied with was clearly demonstrated by the August 2003 Blackout. During 2004 NERC and the industry responded to these needs and the Blackout Investigation recommendations through the development and ratification of the Version 0 Reliability Standards. The ISOs/RTOs concur with NERC’s 2005 objectives to build and improve on the foundation of reliability standards established in Version 0 and complete several high priority standards from the August 2003 blackout recommendations.

ISO/RTOs will participate in the development and prepare consensus comments and positions, as appropriate, for the Reliability standards that NERC plans to develop during 2005:

1. Version 0 adoption and implementation
2. Phase III/IV Planning replacement standards
3. Nuclear Station Off-Site Supply
4. Cyber Security permanent standard
5. Transmission right-of-way vegetation management
6. Organizational Certification of:
 - a. Balancing Authority Function
 - b. Reliability Authority/Coordinator Function
 - c. Transmission Operator Function
7. Complete development of compliance information

Recognizing the need to develop new standards must be balanced with available resources, the IRC anticipates NERC will review proposed standards efforts started before Version 0 and move forward to reach closure on these, as appropriate:

1. Coordinate Operations
2. Operate within Interconnection Operating Reliability Limits (IROL)
3. Determine Facility Ratings, Operating Limits, and Transfer Capabilities
4. System Personnel Training

The IRC recognizes there are other standards projects that are in development or may yet be proposed during 2005. The ISOs/RTOs will work with NERC to balance priorities and ensure that needed standards are developed in a timely manner.

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Functional Model

The Model provides the foundation and framework upon which NERC will develop and maintain its Reliability Standards. While the Model is not a standard, and does not have compliance requirements, the Reliability Standards must respect the definitions and interrelationships contained in the Model. NERC has formed a Functional Model Working Group (“FMWG”) to continue to evolve the Model. IRC will support the FMWG and related groups, working with NERC to seek enhancements to the Model, as appropriate.

Compliance

Compliance with consistently applied standards is essential for maintaining reliability. The ISOs and RTOs be actively engaged in developing and implementing new compliance templates and information to cover all of the Version 0 standards. The IRC will work with NERC to ensure that appropriate penalties are applied uniformly and proper appeals processes are established.

Business Standards Development Activities with NAESB

The ISO/RTOs will assist NAESB in the development of business standards by providing the perspectives and expertise of subject matter experts, as appropriate. The IRC will work with the NAESB WEQ’s Subcommittees, Task Forces, and working groups as they assess issues for potential market impacts and needs for market standards. Through the SRC, the ISOs/RTOs will advise NAESB on issues identified, submit comments in the standards process, and provide joint responses to NAESB.

The IRC will work with NAESB on the following issues in 2005:

- Market Seams, including TLR and ATC issues.
- Complimentary business practices to NERC Reliability Standards (including Version 0 and Version 1)
- OASIS Standards
- Electronic Scheduling Issues
- Gas/Electric Coordination
- Other significant Wholesale Electric Market Operations and Standardization issues, as they may arise.

Coordination with NAESB and NERC

One of the goals of the MOU is to establish and implement a process to coordinate work efforts among NERC, the NAESB WEQ and the IRC in a manner that avoids overlap and duplication of effort. The IRC, through its JIC representatives and the SRC, will work jointly with NAESB and NERC to coordinate standards development and related work efforts of each organization.

Inter-ISO/RTO Information Technology

The ISO/RTOs will look to identify appropriate technologies and opportunities for standardizing inter-ISO/RTO Information Technology (“IT”) processes. Through the

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IRC's Information Technology Committee ("ITC"), the ISO/RTOs will seek to adopt standard technologies and standardize processes and data exchanges unique to ISO/RTOs.

The IRC IT Committee is actively engaged in three initiatives:

1. Data initiative – defines the content of messages exchanged between ISO/RTOs
2. Message Transmission – the mechanics of data exchange
3. Common User Portal – defines interface to create and retrieve messages

The Data initiative will be based on the Common Information Model ("CIM") standard from EPRI. This will be extended to include market data.

The Message Transmission initiative will enable ISO/RTOs to access data across ISO/RTOs through a common portal. This will provide benefits in reliability coordination, outage management, and seams management. Once the scope and schedule are finalized, an implementation schedule will be developed

The Common User Portal will simplify information exchange processes with the ISO/RTOs. It will reduce development costs for each ISO/RTO and transaction costs for market participants. A development plan and requirements schedule is being prepared.

Technologies that may be identified as potential standards that may be applied on a North American basis will be proposed and coordinated through the IRC's Standards Review Committee.



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NERC – NAESB – ISO/RTO Council

Joint Interface Committee

April 29, 2005

Conference Call Minutes

Attendance

NERC Members/Alternates	IRC Members/Alternates
Linda Campbell, FRCC (JIC Co-Chairman)	Karl Tammar, NYISO (JIC Co-Chairman)
Mark Fidrych, WAPA	Bill Limbrick, IESO
Scott Henry, Duke Power	Bill Phillips, MISO
Sam Jones, ERCOT	Charles Yeung, SPP
Ed Schwerdt, NPCC	
Ed Tymofichuk, Manitoba Hydro	
Gerry Cauley, NERC (Secretary)	
NAESB Members/Alternates	Observers
Michael Desselle, AEP (JIC Co-Chairman)	Larita Cormier, Riverside
Ed Davis, Entergy	Dale Davis, Williams Gas Pipeline
Andy Dotterweich, Consumers Energy	DeDe Kirby, NAESB
Barry Green, Ontario Power Generation	Mark Ladrow, NERC
John Hughes, ELCON [Non-voting]	Rae McQuade, NAESB
Alan Johnson, Mirant	
Lou Oberski, Dominion Resources	
Walt Yeager, Cinergy	

Call to Order

Chairman Desselle called the meeting to order.

Quorum

Secretary Cauley announced that each party had reached a quorum.

Antitrust Guidelines

Antitrust guidelines were reviewed.

Agenda

Chairman Desselle reviewed the conference call agenda, which was adopted as presented.

Urgent Action Revision to TLR Procedure

Linda Campbell and Gerry Cauley presented a SAR for an urgent action ballot to revise IRO-006-0, Attachment 1 "Transmission Loading Relief Procedure – Eastern Interconnection". The proposed revision would allow dynamic schedules flowing on firm transmission to continue flowing uninterrupted when an adjustment is made to the tag in accordance with the tagging requirements of INT-004. The request had been submitted by the NERC Interchange Subcommittee and was authorized for posting by the SAC on April 19.

There was discussion whether the change was already encompassed within the scope of a prior action by the JIC to assign the TLR procedure to both NERC and NAESB. There was also discussion whether the requested change was entirely a business practice or both reliability and business practice.

The JIC approved without objection a motion by Lou Oberski to assign the proposed revision to Section 1.6.6 of the TLR procedure to both NERC and NAESB for development.

The JIC agreed that the language in the revised TLR procedure should remain identical in both the NERC and NAESB versions.

Future Meetings and Conference Calls

The JIC tentatively scheduled June 13–14, 2005 as a next meeting date in Tampa.

Adjourn

A motion was approved to adjourn the meeting.

R05004

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Instructions:

1. Please fill out as much of the requested information as possible. It is mandatory to provide a contact name, phone number and fax number to which questions can be directed. If you have an electronic mailing address, please make that available as well.
2. Attach any information you believe is related to the request. The more complete your request is, the less time is required to review it.
3. Once completed, send your request to:
Rae McQuade
NAESB, Executive Director
1301 Fannin, Suite 2350
Houston, TX 77002

Phone: 713-356-0060
Fax: 713-356-0067

by either mail, fax, or to NAESB's email address, naesb@naesb.org.

Once received, the request will be routed to the appropriate subcommittees for review.

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Date of Request: ___03 22 2005_____

1. Submitting Entity & Address:

___NERC Long Term ATC/AFC Task Force (LTATF)_____

2. Contact Person, Phone #, Fax #, Electronic Mailing Address:

Name : _____
Title : _____
Phone : _____
Fax : _____
E-mail : ___ltatf@nerc.com_____

3. Description of Proposed Standard or Enhancement:

It is proposed that a single Business Practice Standard be developed related to both:

- 1) the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM
- 2) the processing and evaluation of request(s) to schedule against approved transmission service reservation(s).

4. Use of Proposed Standard or Enhancement (include how the standard will be used, documentation on the description of the proposed standard, any existing documentation of the proposed standard, and required communication protocols):
 - a. The proposed standard will be applicable to transmission service providers to ensure that consistent practices are employed among transmission service providers when processing requests for transmission service,
 - b. The proposed standard will be applicable to transmission service providers to ensure that consistent scheduling practices are employed among transmission service providers, and
 - c. The proposed standard will be applicable to transmission service providers to ensure that details of the practices and procedures are available to market participants.

5. Description of Any Tangible or Intangible Benefits to the Use of the Proposed Standard or Enhancement:

Providing increased standardization of procedures and better informing market participants of these procedures would enhance market liquidity.

Additionally, this should result in better utilization of the transmission system.

6. Estimate of Incremental Specific Costs to Implement Proposed Standard or Enhancement:

t.b.d.

7. Description of Any Specific Legal or Other Considerations:

Development of this Business Practice needs to be closely coordinated with any work undertaken by NERC that impacts the calculation and coordination of AFC/ATC.

NERC's Long Term ATC/AFC TF (LTATF), which included NAESB participation, has identified a number of issues related to the calculation and coordination of ATC and AFC. Excerpts from the LTATF report are appended to the end of this document.

It is recommended that NAESB develop a Business Practice Standard that would ensure full disclosure as well as standardization where possible of the methodology by which Transmission Service Providers (TSPs):

- Determine the quantity of transmission service to be made available for sale to market participants; and
- Accept schedules for transmission previously purchased

In addition, in developing this methodology, each Transmission Service Provider TSP should, to the maximum extent possible:

- Use similar models and assumptions within equivalent operating timeframes;
- Use models and assumptions for the sale of transmission service that are similar to those used for the planning of the transmission system;
- Assure comparability of service for long term firm point to point and network service customers;
- Assure appropriate coordination between TSPs such that the sale of transmission service by one provider appropriately reflects the impacts on affected systems.

8. If This Proposed Standard or Enhancement Is Not Tested Yet, List Trading Partners Willing to Test Standard or Enhancement (Corporations and contacts):

N/A

9. If This Proposed Standard or Enhancement Is In Use, Who are the Trading Partners:

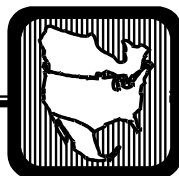
N/A

10. Attachments (such as : further detailed proposals, transaction data descriptions, information flows, implementation guides, business process descriptions, examples of ASC ANSI X12 mapped transactions):

Please see final Long Term AFC/ATC Task Force report on the NERC website at:
www.nerc.com (need to update with full URL when available)

Long-Term AFC/ATC TASK FORCE

FINAL REPORT



March 15, 2005

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Appendix F — CBM Redefinition Options

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Attachments:

AFC/ATC Revision Standard Authorization Request

CBM / TRM Revision Standard Authorization Request

Proposed Business Practice for Processing and Evaluation of Transmission Service Requests

Executive Summary

The Long-Term AFC/ATC Task Force¹ (LTATF) was created by the NERC Market Committee to address the long-term recommendations outlined by the Alliant West TLR Task Force (AWTTF).² The purpose of the LTATF was to develop a report and specific recommendations for the calculation and coordination of AFC/ATC³ to increase market liquidity and enhance reliability. The task force also used the report and recommendations to develop a proposed business practice standard and proposed revisions to related reliability standards, which are included as attachments to this report.

The major areas the task force considered were:

- Communication and Coordination of AFC/ATC (respecting 3rd party constraints)
- Calculation Process for AFC/ATC
- Consistency between planning criteria and the attributes of the AFC/ATC calculations (over both planning and operating horizons)

The task force also evaluated the results of the short-term recommendations of the AWTTF in the Alliant West area for summer 2004 and used this evaluation to recommend that the Alliant West short-term recommendations be extended to March 31, 2005, from the original expiration date of September 30, 2004. See Appendix D.

The NERC Market Committee directed the task force's efforts, and the task force coordinated its work with representatives from NAESB. The task force met nearly monthly from June 2004 through March 2005 to expedite the completion of its work.

Background

Since FERC's Order 888 first mandated the sale of transmission service by FERC-jurisdictional entities to wholesale electric customers, thus necessitating the explicit calculation of ATC, the industry has evolved significantly.

Although some progress was made publicizing and defining an algorithm for ATC calculations in Order 888 and the NERC Board of Trustees approved a document entitled "*Available Transfer Capability Definitions and Determination*,"⁴ an industry-wide methodology still does not exist today.

Furthermore, as the industry has discovered, during the work of the AWTTF and now with the LTATF, the lack of standardization and more significantly, limited coordination can negatively impact both the market, through the need for a large number of Transmission Loading Relief (TLR) actions (or curtailments in WECC) and, on occasion, reliability when even the use of TLRs provides insufficient relief on some critical interfaces.

¹ See Appendix G for the LTATF roster.

² The Alliant West TLR Task Force (AWTTF) was created during the November 2003 Standing Committee meetings to develop specific recommendations for market and operating practices to address problems associated with TLR curtailments in the Alliant West region expected in summer 2004. Its report is available on NERC website at: ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/AWTTF_FERC_Filing_040204.pdf

³ Available Flowgate Capability / Available Transfer Capability

⁴ ftp://ftp.nerc.com/pub/sys/all_updl/docs/pubs/atcfinal.pdf

There are also other elements of the industry's evolution that have changed the nature of the calculations and the interactions between neighbouring transmission providers. These include:

- The use of Available Flowgate Capability (AFC) calculations in conjunction with ATC.
- The development of centralized markets resulting in market to non-market interfaces.
- Agreements between neighbouring ISOs/RTOs and transmission service providers that have resulted in the increased coordination of operation and transmission service request processing.

While these changes have modified the relationship between Transmission Service Providers (TSPs), they have not reduced the relevance of ATC or AFC to both market participants and reliability coordinators. There is still a need for further industry-wide improvement because of continuing outages, curtailments, TLRs, and other reliability and commercial concerns.

Other appendices contain two proposed NERC standard authorization requests, a proposed NAESB business practice standard, and additional information related to the topics covered by the task force and used as a foundation for the development of the proposed standards.

LTATF AFC / ATC Discussions and Analyses

During the course of the LTATF investigation, the task force developed three groups of issues:

1. Communication and Coordination of AFC/ATC — respecting 3rd party constraints
2. Calculation Process for AFC/ATC
3. Consistency between planning criteria and the attributes of the AFC/ATC calculations (over both planning and operating horizons).

Those three issues are further outlined below:

1. Communication & Coordination of AFC/ATC — respecting 3rd party constraints

The objective of ATC/AFC coordination is to ensure that neighboring entities exchange relevant information to facilitate:

- a. a reasonable representation of external entities in the model for calculating AFC/ATC;
- b. the ability for each Calculator to honor flowgates in third party systems; and
- c. the ability for each Calculator to translate data from neighboring entities and make meaningful use of the data in their respective calculations.

Further details are contained in *Appendix A*.

2. Calculation Process for AFC/ATC

The task force agreed that TSPs need to provide better documentation and greater transparency for their AFC/ATC calculation processes.

- a. The proposed Standard Authorization Request (SAR) contains recommendations to achieve more consistency among AFC/ATC calculations.
- b. The task force conducted a review of ATC methodologies and found that numerous ATC calculators in the Midwest have been replaced with MISO and PJM.
- c. Additionally, the task force found industry-wide approximately 50–60 ATC calculators (TSPs posting to their OASIS website), with many (30–40) in the West.

- d. The task force also felt that consistency is important in the calculation of Capacity Benefit Margin (CBM) and Transmission Reserve Margin (TRM), and is reflected in the attached SAR recommending a revision to the applicable standards.

The task force found several different ways ATC, TTC⁵, TRM, and CBM are calculated and used, and are dependent on the type of market system utilized and electrical topology.

Following are some examples:

- Some first calculate TTC and then derive ATC
 - Some first calculate ATC and then derive TTC
 - Some first calculate AFC and then derive ATC
 - Some only calculate TTC
 - Some use CBM and some don't use CBM
 - The scope of CBM varies by footprint
 - Nearly all use TRM
3. Consistency between planning criteria and the attributes of the AFC/ATC calculations (over both planning and operating horizons)
 - a. The task force emphasized the requirement that assumptions used in the calculation of AFC/ATC and CBM/TRM should be consistent with those used in the respective planning and operating horizons (see Appendix E). The assumptions should be documented and transparent to stakeholders.

⁵ Total Transfer Capability

LTATF Recommendations and Other Issues

Data Input and Utilization — Calculation Process for AFC/ATC

- I. The task force recommends that NERC should establish minimum data entry and utilization requirements with standardized data definitions and definitions for the frequency and timing for exchanging data.
- II. The task force recommends that TSPs should be required to publish their methodology for the calculation of ATC or AFC, detailing how they deal with all of the items identified in Appendix A, or state why they are not relevant to their calculation.
- III. Standardization of the treatment of these items remains an additional objective. This information should be provided according to a template to be included as part of the compliance with the proposed NAESB Business Practice Standard and/or proposed revisions to Reliability Standards that are attached to this report.

TRM/CBM — Calculation process for AFC/ATC

The LTATF passed the following strawman motion by a vote of 15 to 2:

Because the LTATF debated at length the merits of CBM calculation and utilization, the LTATF asks the SAR Drafting Team (SAR DT) to consider whether the calculation and/or withholding of CBM as an explicit quantity is necessary for reliability and should be part of a reliability standard.

If the industry still considers CBM to be necessary, the SAR DT is asked to consider the following recommendations:

- IV. The task force recommends that NERC revise its standard on the calculation of CBM/TRM and that NAESB establish a standard on the use of CBM that would replace the NERC CBM standard associated with the use thereof.
- V. The task force recommends that NERC and complementary NAESB standards should require transparency, *but not be a prescriptive methodology*, for the calculation and use of CBM/TRM.
- VI. The task force recommends that NERC standards should provide guidelines for parameters that should be included in the TRM/CBM calculation, and reconcile methodologies where a RTO might cover several regions with differing methodologies.

See Appendices C and F.

Monitoring/Coordination — Communication and Coordination of AFC/ATC

- VII. The task force recommends the revision of the existing NERC standards to require the recognition and respect of impacts on external flowgates/paths in AFC/ATC calculations, and the establishment of NERC standards on AFC/ATC coordination.

Frequency of Calculations — Calculation Process for AFC/ATC

- VIII. The task force recommends the revision of NERC standards to increase the frequency of AFC/ATC calculations (e.g., see Appendix D on Alliant West recommendations).

Source and Sink Points - Calculation Process for AFC/ATC

The task force suggests that the sources and sinks (injections and withdrawals) used in the calculation of AFC/ATC and the evaluation of transmission service requests should replicate the anticipated use of service when utilized. It is important that TSPs have business practices outlining when they will allow confirmed transmission reservations to be used in manner that is not equivalent to how the request for the service was evaluated.

- IX. Therefore, the task force recommends that the NERC SAR DT establish or revise an existing standard to ensure that the calculation of AFC/ATC and the evaluation of the transmission service request reflect the anticipated usage of that service when that service is utilized.
- X. The task force also recommends that NAESB develop a business practice standard that relates to the processing and evaluation of request(s) to schedule against approved transmission service reservation(s). See Appendix B for additional details.
- XI. The task force also recommends that the SAR DT should review or create FERC / NERC definitions and utilizations of source and sink when revising the standard.
- XII. The task force also recommends that that NAESB develop a Business Practice Standard related to the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM. (see attached proposal for a NAESB business practice standard)

Curtailement Threshold Consistency — Calculation Process for AFC/ATC

The task force discussed distribution factor cutoff consistency between calculation of AFC/ATC and activation of TLR. The task force acknowledged existing inconsistencies among TSP practices. The task force did not reach a conclusion regarding an appropriate curtailment threshold level, and suggests that a larger stakeholder body would be necessary to reach a consensus.

Appendix A

ATC/AFC Coordination and Calculation

NERC LTATF

LTATF Appendix on AFC/ATC Coordination and Calculation

1.0 Introduction:

The purpose of this paper is to provide an overview of the process of calculating and coordinating transfer capability (AFC/ATC). The paper outlines existing coordination processes in the Eastern Interconnection (EI) and the WECC. The paper also defines a proposed method of exchanging ATC/AFC data between entities. The last section is a summary of minimum requirements for flowgate exchange and modeling techniques to facilitate proper calculation and coordination of transfer capability (AFC/ATC).

2.0 Coordination:

The objective of ATC/AFC coordination is to ensure that neighboring entities exchange relevant information to facilitate:

- a) a reasonable representation of external entities in the model for calculating AFC/ATC
- b) the ability for each Calculator to honor flowgates in third party systems
- c) the ability for each Calculator to translate data from neighboring entities and make meaningful use of the data in their respective calculations

The NERC SDX is a platform for data exchange between the various NERC regions. Several entities have developed alternate platforms to exchange data as a supplement to data exchange via SDX. Each NERC region has its own document outlining the coordination and calculation of transfer capability by its members.

Following is a summary of the coordination processes in place in major regions in NERC:

Eastern Interconnection:

In the EI, several entities have signed operating agreements to facilitate the coordination process. The following agreements are currently in effect or have been filed with the FERC:

- a) MISO – PJM¹
- b) MISO – MAPP²
- c) SPP - MISO³

SERC and FRCC members consist predominantly of ATC calculators. Coordination standards for SERC members are outlined in the SERC supplement⁴ to the NERC planning standards.

Western Interconnection:

WECC members coordinate transfer capability through seasonal studies⁵.

¹ <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf>

² http://www.midwestiso.org/initiatives/joa_seams/mapp_seams/docs/Final_SOA_modified_01142005.pdf

³ http://www.midwestiso.org/initiatives/documents/12-02-04%20FERC_Filing_SPP-MISO-JOA.pdf

⁴ <http://www.serc1.org/Pages/DocumentDisplay.aspx?FN=SERC%20Supplements/Planning/IE1%20SERC%20Supplement%203-8-02.PDF>

⁵ <http://www.wecc.biz/documents/library/procedures/ATC-apprdec01.pdf>

LTATF Appendix on AFC/ATC Coordination and Calculation

2.1 Exchange of data between and AFC and ATC calculator:

This section outlines an option to enable entities to exchange useful information on flowgates for use in their calculations.

2.1.1 AFC calculator reading data from ATC calculator:

- ATC calculator determines CE/LE (contingent element/limiting element/monitoring element) pairs that are limiting to transfers
- List is sorted to identify CE/LE pairs that are in the list of monitored flowgates for the AFC calculator
- For these CE/LE pairs, an equivalent AFC value is transmitted to the AFC calculator.

2.1.2 ATC calculator reading data from AFC calculator:

- AFC calculator supplies list of flowgate AFC values to the ATC calculator
- ATC calculator translates the AFC value into the model by adjusting the rating of the LE such that under contingency or non-contingency (as appropriate for the specified flowgate), the adjusted rating - flow (LE) equals the AFC value supplied by the AFC calculator

2.2 Flowgate data exchange and modeling requirements:

This section outlines the list of flowgates that should be considered for the coordination process. The section also defines modeling requirements for entities performing the transfer capability calculations.

2.2.1 Each TSP will consider in its TTC and ATC/AFC determination process all third party flowgates:

- (i) that are significantly impacted by its transactions, or
- (ii) as mutually agreed between the parties, subject to the following:
 - A TSP's transactions are deemed to significantly impact another TSP's flowgates if they have a response factor equal to or greater than the response factor cutoff (threshold) used by the owning TSP.
 - The parties, in their AFC determination and transmission service processing efforts, shall use the response factor cut-off that the owning/operating TSP uses for its flowgates.
 - The TSPs shall coordinate their counterflow assumptions on affected flowgates.
 - At a minimum, coordination should occur on flowgates in transmission systems that comprise the first tier with respect to the TSP.
 - To the extent a TSP is coordinating AFC on a requested flowgate, the TSP needs to ensure that modeling around the flowgate is sufficient to produce reasonable response factors. As an alternative, the TSP can use response factors provided by the requesting TSP.

LTATF Appendix on AFC/ATC Coordination and Calculation

2.2.2 All entities should meet the following minimum modeling requirements:

- Transmission providers should use reasonably accurate response factors
- Model should include the TSP's control area as well as control areas within the footprint of the adjacent TSP's tariff
- Equivalent model representations for beyond first-tier transmission providers / control areas are acceptable as long as they enable calculation of accurate response factors
- Use of an MMWG base case, modified by appropriate NERC SDX system conditions, would be considered a reasonable alternative
- If an area is too small or its model too limiting, it should delegate its calculations to an entity that has the capability to perform the calculations with appropriate modeling capabilities

2.2.3 In the absence of a mutual agreement, or for a waiver from this requirement, NERC or its designate shall define for the TSPs those external system modeling requirements to be used for TTC/ATC/AFC calculations.

Glossary

<i>TTC</i>	<i>Total Transfer Capability</i>
<i>ATC</i>	<i>Available Transfer Capability</i>
<i>AFC</i>	<i>Available Flowgate Capability</i>
<i>SDX</i>	<i>System Data Exchange: NERC tool to facilitate electronic data exchange</i>
<i>MMWG</i>	<i>Multi-regional model working group (NERC working group responsible for power flow model development)</i>
<i>TSP</i>	<i>Transmission Service Provider</i>
<i>CE/LE</i>	<i>Contingent Element/Limiting Element; typically used to identify facilities that define a flowgate</i>
<i>OTDF</i>	<i>Outage Transfer Distribution Factor</i>
<i>PTDF</i>	<i>Power Transfer Distribution Factor</i>
<i>LODF</i>	<i>Line Outage Distribution Factor</i>

LTATF Appendix on AFC/ATC Coordination and Calculation

1. ATC/AFC Equations

Basic transmission service is sold to customers in the form of “Transfer Capability” (TC). Available Transfer Capability (ATC) is the amount of transfer capability still available for sale after all existing uses are accounted for. Transfer Capability (TC) is measured along a path from source to sink. Transfer Capability is limited by the capacity of either equipment (such as transformer, circuits) or interfaces (collection of circuits). An example of an interface limit would be a voltage or stability limit that can be measured as a maximum flow on an interface or a thermal contract path limit.

A “flowgate” is the name given to the transmission element(s) and associated contingency if any, that may limit ATC. Available Flowgate Capability (AFC) is a measure of the capability remaining on a flowgate for future uses, after considering the impact of prior sales. AFC is measured as a “flow” limit on a flowgate, while ATC is measured as a “transaction” limit from a source to sink. There are typically several flowgates between source and sink that can limit the transaction. Transactions distribute amongst these flowgates based on the transmission configuration. The percent distribution of a transaction on a flowgate is determined via power flow analysis and is called a distribution factor (DF) (this term is interchangeable with “response factor”) whereby:

$$AFC(f) = DF(t,f) * ATC(t,f)$$

t = defined path from source to sink

f = flowgate “f”

ATC(t,f) = The maximum transaction for path t available as limited by flowgate “f”

AFC(f) = AFC for flowgate “f”

DF(t,f) = percentage of transaction on path that flows on flowgate “f”

Typically, AFCs are determined for all flowgates and ATC is then determined from AFC. For this reason, the equation is more frequently used in the format:

$$ATC(t,f) = AFC(f)/DF(t,f)$$

The overall “ATC” is the “minimum” ATC calculated from the above equation for all flowgates. Posted ATCs must therefore have an associated “most limiting” flowgate. Each flowgate has an associated AFC for the time frame being studied, which can be used to calculate an ATC for any potential path.

Other Relationships:

Total Flowgate Capacity (TFC) is generally equal to the *rating* of the flowgate. A typical flowgate might consist of a limiting circuit, or “monitored” circuit, along with the outage that limits the monitored circuit. An “interface” flowgate’s AFC is typically set to a flow value above which a stability or voltage limit will be exceeded.

LTATF Appendix on AFC/ATC Coordination and Calculation

Basic Equations:

AFC = TFC – Base Network Flows(Native & Network load model) – Margins (such as CBM/TRM) – Effect on the flowgates of existing transmission reservations

Margins:

Capacity Benefit Margin (CBM)¹ or Transmission Reserve Margin (TRM)¹ are margins used in ATC or AFC calculations to account for uncertainties or contingencies that are not explicitly modeled in the calculations due to time constraints. The criteria used to determine these values must be consistent with the TO's planning and operating criteria. A more detailed description of these margins can be found in the NERC white paper titled "Transmission Capability Margins and Their Use In ATC Determination" dated June 17, 1999.

2. Translation of ATC/AFC for Data Exchange Between Entities

Sharing of ATC/AFC quantities between entities, which sell transmission service, requires translating the data from ATC to AFC (& vice versa) if one of the entities uses ATC and the other uses AFC as a basis. The basic AFC/ATC equations discussed earlier can be used to "translate" shared data:

$$ATC(t,f) = AFC(f)/DF(t,f)$$

Where:

(t) is a defined source to sink transaction

(f) is any flowgate

DF is the distribution factor on the flowgate of the defined source to sink transaction.

Defined source to sink transactions are those qualifying for transmission service. For example, if two RTOs are coordinating data and the transaction is from a source in one to a sink in the other the direct path is usually not available. The transaction would be from the source in RTO number 1 to a border interface with RTO number 2. The transaction in RTO number 2 would be from the border interface to the sink in RTO number 2. Each RTO would be responsible for its portion of the transactions. Even if the transmission purchaser is oblivious to the intervening interface, the RTOs share their own piece of the calculation. This situation has the inherent problem that the true source to true sink is ignored when a "border" is introduced. It is a similar problem to "hubbed" transactions where transactions are ultimately split from the source to the "hub" and then from the "hub" to the sink.

1 "Transmission Capability Margins and Their Use in ATC Determination - White Paper" NERC ATCWG document dated 9/28/99. Available from the following URL:
<http://www.nerc.com/~filez/atcwg.html>

Appendix B

Source / Sink

NERC LTATF

LTATF Appendix on Source/Sink

1. Introduction

The purpose of this appendix is to provide guidance on “source” and “sink” point assumptions used in AFC/ATC calculations and in the evaluation of Transmission Service Requests.

2. Source/Sink Points in Transmission Analysis

The assumptions of source and sink points are fundamental in the determination of transfer capability. The North American Electric Reliability Council (*in “Glossary of Terms” – August 1996*) defines Transfer Capability as follows: It is “the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another area by way of all transmission lines between those areas under specified system conditions.”

The Transfer Capability between two areas is typically assessed or determined by modeling a generation excess in the “from” area at a specific source point(s) and a generation deficiency in the “to” area at a specific sink point(s). The increased source level at which the loading on a transmission element is at its normal rating (with no contingencies) or its emergency rating (with an outage of a generation unit or a transmission element) is defined as the incremental Transfer Capability.

Selection of the specific source and sink points will impact the calculated “power transfer distribution factors” and various transmission facility loadings to determine the AFC/ATC values and to determine the anticipated impact of a Transmission Service Request on specific Flowgates. Therefore, the posted AFC/ATC, as well as the evaluation of a transmission service request, is greatly influenced by the selection of these points. Transmission service sold based on a set of source/sink points that do not correspond to the generation that moves for the schedule results in inaccurate ATC values.

3. Source and Sink Point Concepts

Source and sink points, for the purpose of this appendix, do not necessarily correspond to the source or sink fields on a transmission reservation, but are constructs that mimic the expected actual change in generation dispatch that would be used to affect that power transfer in real-time. When determining a Transfer Capability (or determining ATC/AFC or evaluating a transmission service request) by modeling a power transfer, there are several ways to model the various source and sink points. Source/sink points have the following general characteristics:

- a. Source points could be generalized into the following four categories:
 - i. Increase generation level of an individual unit or units at a station
 - ii. Increase generation level of a group of units that represent a system dispatch
 - iii. Load Reduction (if there is no available generation in the source system)
 - iv. A combination of increasing generation and reducing load

LTATF Appendix on Source/Sink

- b. Sink points could be generalized into the following four categories:
 - i. Decrease generation level of an individual unit or units at a station
 - ii. Decrease generation level of a group of units that represent a system dispatch
 - iii. Load increase when the sink area is not at projected peak
 - iv. A combination of decreasing generation and increasing load

- c. Sources and Sinks Modeled at a Single Bus

Load reduction at a single bus would not usually be considered a valid source in the ATC/AFC calculations. A load increase on a single bus should be considered a valid sink only when a designated load is modeled entirely on that one bus.

- d. Source and Sink Points as a Group of Load Points

Similar to a single bus, a group of load buses is not typically considered a valid source unless there is no available generation in the source system. Load can be considered a valid sink point if the sink system is not at the anticipated peak load or if no sink system generation is available to scale down.

- e. Source or Sink Point from a Single Unit or Plant

Although utilizing a single unit or plant as a source or sink is acceptable, the provider must be careful to ensure the methodology is technically correct if/when reservations exceed the capability of the unit or plant, how redirects are handled and how service decrements flowgates.

- f. Source and Sink Points as a Group of Units

If a group of units or a control area is utilized as source and/or sink points, the following needs to be addressed in the transmission provider's ATC/AFC methodology.

The assumptions used in the creation of the 'subsystem' should mimic the dispatch of these units in real-time conditions. For example, issues that must be considered include economic dispatch order, jointly owned units, intermittent resources (e.g. wind and run of the river hydro) and how the ATC calculation will address the potential of generation modeled in excess of capacity (when the fleet is a source) and/or generating 'negative' generation (when the fleet is a sink).

When determining participation points, consideration needs to be given to whether the source or sink subsystem is dispatched by a single entity, such as a centralized market dispatch, a vertically integrated utility, or if all generators in a locality, including municipal generation and IPPs, are part of the single subsystem. The transmission provider must rationalize the consistency of these assumptions with real time operations.

LTATF Appendix on Source/Sink

- g. Source and sink points used to represent the source or sink area being studied need to be physically located in those areas. To the extent possible, the ultimate source and ultimate sink should be utilized, not just source and sink points at the border or in the first tier of the transmission provider.
- h. The source and sink on the energy tag should match the sources and sinks used to evaluate the transmission service request. (This is a scheduling issue)

4. Conclusion

Source and sink assumptions are a critical ingredient in the determination of ATC values. To the extent practical these assumptions need to reflect the actual generation dispatch used to implement a power transfer between two entities. If the source/sink assumptions do not reasonably mimic real time operations, the resultant ATC will reflect this inconsistency through values that result in overselling of transmission or the underutilization of the transmission capacity. In the case of over-estimation of ATC, the transmission system could be oversold, resulting in avoidable operating challenges in real time, including TLRs and curtailments, as well as generation costs associated with a less than efficient generation dispatch. In the case of underselling the transmission system, due to under-estimation of ATC values, the results are missed opportunity costs due to the underutilization of the transmission system.

It is important that the transmission provider document how sources and sinks are established and utilized in their ATC/AFC process to ensure consistency and to ensure that the methodology is validated.

Appendix C

Review of Current NERC Standards on CBM and TRM

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LTATF Appendix on the Review of Current NERC Standards on Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM)

The purpose of reviewing the current NERC standard on CBM and TRM was to determine if there were any deficiencies that could be addressed in a new proposed standard for Available Transfer Capability (ATC) and its associated margins CBM and TRM. In general, it was determined that the standard could be improved in the four following categories:

1. Independent Review
2. Consistency
3. Additional Specificity Where Feasible
4. Seams Issues

These four categories could possibly also apply to the current NERC standard on ATC calculations. Additional details of the review are as follows:

Independent Review

The current CBM and TRM standard calls for Regional Reliability Organization (RRO) methodologies to be established. The Regional methodologies are reviewed by NERC to determine if they address the subject matter listed in the standard. There is no judgment made regarding if the methodology is reasonable or correct. The Regions then review the ATC calculators in their areas to determine if they are following the methodology.

It is recommended that a new standard require a written methodology and be very specific regarding what subject matter is covered in the written methodology. The standard drafting team should also consider a requirement that all documents be in a specified format or at least follow the same outline. The standard would only require that the methodology address all specified subject matter and be publicly available. Any issues regarding the methodology or its resulting values would not be addressed by the standard, but would be addressed via an open process that the standard would require the owner of the methodology to have. Any dispute resolution would be handled by NERC or its designate.

To keep the number of methodologies to be reviewed to a reasonable number the following entities would be required to have written methodologies:

- RTOs and ISOs that calculate TRM and/or CBM would be required to have written methodologies that incorporate input from those RROs that are within or partially within the RTO/ISO.
 - **Would an RTO methodology be subject to FERC or NERC?**
 - **NERC or NAESB, as appropriate**
- Where the TO is not part of an RTO, individual transmission owners (TO) that calculate their own TRM and/or CBM or provide input data to a centralized AFC/ATC process where the calculation is done on their behalf must abide by a RRO methodology.

To provide consistency in the reviews, a single entity such as NERC or its designate must review all the methodologies to determine if they are compliant with the standard.

In addition, NERC or its designate will review the ISOs and RTOs who calculate TRM and/or CBM to determine if they are following their methodologies. Any TOs who are determining

LTATF Appendix on the Review of Current NERC Standards on Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM)

their own TRM and/or CBM values must be reviewed by the entity whose methodology they are using, to ensure consistency with the methodology. The reviews of the individual TO calculations must be summarized and the reports reviewed by NERC or its designate.

Consistency and Additional Specificity Where Feasible

The existing CBM and TRM standard could be more specific in the following areas:

1. Frequency of calculation must be at least annually or upon any change pursuant to FERC Order 889.
2. Provide guidelines for the following items in the CBM standard
 - a. Item 1e. Generator resources
 1. All generation directly connected to the TSP's system being used to serve load directly connected to that system would be considered in the CBM requirement determination.
 2. All generation not directly connected to the TSP's system being used to serve load directly connected to that system will be considered as "perfectly available" generation in the CBM requirement determination.
 - b. Item 1f. Definition of generators connected to the system
 1. The following units are included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined:
 - All generation directly connected to the TSP's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.
 - All generation not directly connected to the TSP's system being used to serve load directly connected to that system will be considered as perfectly available generation in the CBM requirement determination.
 - Generation directly connected to the TSP's system but not obligated to serve load directly connected to that system, will be incorporated into the CBM requirement determination as follows:
 - Generation directly connected to the TSP's system but committed to serve load on another system will not be included in the CBM requirement determination for the transmission system to which the generator is directly connected. These units are not included because they are committed to serve load on another system and therefore not available to serve load on the system for which the CBM requirement is being determined.
 - Generation directly connected to the TSP's system but not committed to serve load on any system will be included in the CBM requirement determination for the transmission system to which the generator is directly connected as follows:

LTATF Appendix on the Review of Current NERC Standards on Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM)

- a. The TSP will use the best information available to them (i.e. confirmed or requested transmission service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.
 - b. If no information on these units is available, the TSP will use the following default: Fifty percent of the generation directly connected to the TSP's system but not committed to serve load on any system will be included in the CBM requirement determination. By including all this generation, the CBM requirement may be reduced too much, and by excluding it the CBM requirement may be increased too much. Since this generation is uncommitted, there is a 50/50 probability that the energy will or will not be purchased to serve load connected to the TSP's system. Using the 50% value is a midpoint between the two extremes (using all the uncommitted generation or using none of the uncommitted generation).
3. Consistency with Planning Criteria
 - a. The existing CBM standard already requires this consistency
 - b. The TRM standard must require that the components that comprise the TRM are planned for by the TO or other planning entity.
 - c. The entity responsible for the CBM/TRM Methodology will be required to review the TO or other planning entity to ensure there is consistency with their planning criteria. The planning criteria consistency reviews will then be reviewed by NERC or its designate.
 4. Dates that seasonal CBM and TRM values apply must be specified in the methodology

Seams Issues

The existing CBM and TRM standard could be more specific in the following area:

1. Coordination of CBM and TRM values on flowgates especially tie-lines. (This issue can be covered in the AFC/ATC standard under coordination)

Appendix D

Evaluation of the AWTTF Short-term Recommendations

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Evaluation of the AWTTF Short-term Recommendations

I. Emergency Redispatch

For the identified Alliant West flowgates, the reliability coordinators shall identify key redispatch combinations and develop operating procedures that would relieve the defined Alliant West flowgate constraints in the event emergency redispatch was quickly needed to prevent an imminent threat of collapse, cascading or significant loss of load.

STATUS: MISO has identified three situations under which emergency dispatch will be implemented:

1. *If the actual real-time flow on the monitored element exceeds the emergency rating, the MISO RC shall order immediate emergency redispatch using any combination of the increment and decrement units.*
2. *If the calculated post-contingency loading on the monitored element is greater than 100% but less than 125% of the monitored elements emergency rating, the MISO RC will institute TLR to return within 100% of the emergency rating. If there is insufficient relief available from TLR or relief is not being accomplished within 60 minutes of the initial surpassing of the emergency limit, the MISO RC will order emergency redispatch. The emergency redispatch must be ordered to arrest the problem within 60 minutes of the initial surpassing of the post-contingent emergency rating*
3. *If calculated post contingency loading on the monitored element is greater than 125% of the monitored element's emergency rating, the MISO RC will implement emergency dispatch immediately. The emergency redispatch must be ordered to arrest the problem in 30 minutes of the initial surpassing of the post contingent emergency rating.*

II. Planning

Alliant and MISO should ensure that planning studies are underway to identify what transmission facilities would need to be upgraded or added to accommodate known firm transactions and reliability needs in the Alliant West area.

STATUS: MISO Expansion Planning Group study will be factoring in Alliant West flowgates for the creation of a 2009 base case for the MISO Transmission Expansion Plan. Alliant will be conducting an eastern Iowa study with the Iowa Transmission Working Group.

Alliant has initiated their Transmission Planning Study.

III. Source and Sink Points

- a. Within 10 days following a TLR level 5 or higher MISO shall work with other transmission providers to investigate all transaction pairs within the IDC having an impact of 3% or greater on the designated Alliant West flowgate that exist each hour of the TLR 5. The NERC TLR report will, for each schedule flowing during TLR 5, give evidence that generators designated for the schedule through the approval process that were specified as a POR were actually on line delivering sufficient energy for the schedule(s), at the time of the TLR5.
- b. If the unit that was designated as part of the schedule was not on line, the Midwest ISO shall request and report the response of the entity responsible (PSE, TP, etc) for the schedules as to what the actual source of the schedule was at the time of the TLR.

STATUS: MAPP is committed to gathering data. MISO has established procedures for those cases where transmission is granted on a unit specific basis.

LTATF Appendix on the Review of the Evaluation of the AWTTF Short-term Recommendations

IV. AFC Coordination

- a. Updated Alliant West flowgate AFC values will be made available (was scheduled for implementation by March 10th) by MISO as follows:
 - i. For hourly, once per hour
 - ii. For daily, once per hour (calculated four times per day)
 - iii. For monthly, once per hour (calculated twice a month)
- b. For the evaluation of transmission service requests, the identified transmission providers should utilize the updated AFC from MISO at the frequency noted below:
 - i. For hourly, once per hour.
 - ii. For daily, once per day
 - iii. Monthly, once a week

For those transmission providers that cannot meet the recommended frequency, provide an indication to NERC of why and what is possible by June 1, 2004, and when they would anticipate being able to fully meet the recommended frequency.

- c. Transmission providers shall not approve additional hourly, non-firm transmission during the expected remaining duration of a TLR Level 3 or higher curtailment, or until the TLR Level 3 or higher has ended, for those reservations that negatively impact (3% or greater) the designated Alliant West flowgates. This requires that transmission providers recognize the hourly AFC/ATC values provided by MISO during TLR level 3 or higher.

STATUS: PJM, SPP, Grid America, MISO (including Ameren and IP), MAPP (for non-MISO members) and AECI indicated that they are meeting the frequency called for above.

V. Monitoring

The identified transmission providers listed on page three¹ must monitor the identified Alliant West flowgates using a 3% OTDF threshold, unless MISO agrees that it is not required. AFCs will be provided for these flowgates by MISO and those AFC values must be implemented in any AFC/ATC calculation process and transmission service request evaluation process of the transmission providers specified below.

For those transmission providers that cannot meet the monitoring request, provide an indication of why and what is possible by June 1, 2004, and when they would anticipate being able to fully meet the recommended monitoring.

STATUS: PJM, SPP, and AECI indicated that they are monitoring the flowgates as described above.

VI. NERC IDC Tool and Policy (for a test period of June 1, 2004 to September 30, 2004)

- Step 1. TLR Level 3 procedures will be used as it exists today to curtail non-firm transactions, including appropriate Level 4 reconfiguration
- Step 2. If overloads still exist after step 1, prior to going to TLR Level 5, proceed to curtail remaining non-firm transactions (including Non-designated Network Resource 6-NN) using 3% as the threshold.
- Step 3. After step 1 and step 2, if overloads still exist, initiate Level 5 under current TLR procedures using a 5% threshold

STATUS: MISO indicated that from June 1, 2004 to June 7, 2004 there had not been a TLR Level 5. However, MISO has been prepared to implement the applicable procedures should a TLR 5 occur. There was one instance of a TLR 5 on June 30, 2004.

¹ page 3 of the final AWTTF report

Appendix E

Consistency Between AFC/ATC Calculations and Transmission Owners' Planning Criteria

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LTATF Appendix on the Consistency Between AFC/ATC Calculations and Transmission Owners' Planning Criteria

The intent of this appendix is to discuss the concept of consistency between AFC/ATC calculations and Transmission Owners' planning criteria. The NERC ATCWG reached conclusion on the following rule as they were developing the "Transmission Capability Margins and Their Use in ATC Determination" white paper which discusses the reliability margins of TRM and CBM:

A Transmission Provider's ATC/AFC calculations, and associated margins, must be consistent with the Transmission Owners' and Public Power Entities documented Planning Criteria

This rule was incorporated into the "Transmission Capability Margins and Their Use in ATC Determination" white paper dated June 17, 1999 as demonstrated in the following two excerpts:

- "The methodology used to derive TRM and its components must be documented and consistent with published planning criteria, and must not account for uncertainties already accounted for elsewhere in the ATC determination. A TRM is considered consistent with published planning criteria if the same components that comprise it are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process"
- The methodology used to derive CBM must be documented and consistent with published planning criteria. A CBM is considered consistent with published planning criteria if the same components that comprise the CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.

The rule was also incorporated into the existing Planning Standard for CBM and TRM as the following excerpts indicate.

- "Each Region's CBM methodology shall:
Specify that the method used by each Regional member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria".
- "This Regional procedure shall:
Require review of the consistency of the transmission provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process".

LTATF Appendix on the Consistency Between AFC/ATC Calculations and Transmission Owners' Planning Criteria

All transmission service requests must be evaluated consistent with each Transmission Owner's planning criteria in order to maintain reliability. Transmission service requests must not be subject to evaluation scenarios that exceed or are 'beyond' the applicable planning criteria. For example, if the most extreme event a Transmission Owner plans for were single contingencies, it would be inconsistent with the applicable planning criteria to evaluate a transmission service request to meet a double contingency test. In this instance, evaluating a transmission service request using double contingency analysis would be in conflict with the planning criteria and would not be compatible with the reliability requirements used to serve native connected load. In an ATC calculation the following components determine the loading on a flowgate for the period of time under evaluation:

1. Base Case Flows (which recognizes the forecasted load connected to the transmission network and planned system topology)
2. Impacts of existing transmission service reservations -- both positive and negative (i.e. counterflow)
3. TRM (consistent with applicable Planning Criteria)
4. CBM (consistent with applicable Planning Criteria)

When these four components are applied to a flowgate the result is a calculated AFC. If the resultant AFC is negative, the result indicates that the flowgate is projected to be overloaded because of the preexisting commitments (i.e. the four components listed above). In some cases negative AFC values exist for future years preventing transmission customers from obtaining transmission reservations for these future time periods.

The inconsistency between Transmission Provider's AFC/ATC calculations and the Transmission Owner's Planning criteria becomes evident when the Transmission Owner internal planning processes does not result in identification of system deficiencies requiring system expansion – even on Flowgate determined by the Transmission Provider to have negative AFC values far into the future. The likely cause of this discrepancy is that the TO is not applying the same scenario, including the same transmission uses (i.e. confirmed reservations), or consistent margins (TRM/CBM) in its internal planning process as is occurring in the ATC calculations. The following questions need to be answered affirmatively for the two processes to be consistent:

1. Are base case flows, impact from reservations, TRM and CBM that are all forecasted to occur simultaneously being considered in the planning process as they are in the ATC process?
2. Are the same counterflows being considered in the two processes?
3. Are the same positive impacts being considered in the two processes?
4. Are the components of TRM being considered in the planning process in a similar manner as the ATC process?
5. Is CBM being considered in the planning process in a similar manner as the ATC process?

Any new standard on ATC calculations and its margins of CBM and TRM need to address this issue. These revised standards must require consistency between the applicable Planning Criteria and ATC process. The consistency needs to be reviewed to ensure that what is applied in ATC calculations is being planned for by the TO. TOs may determine that they do not want to plan for 100% of positive impacts from reservations and may want to use varying amounts of counterflow on various flowgates.

Appendix F

CBM Redefinition Options

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CBM Applicability in an RTO Environment

Earlier in the development of this industry, there were predominately ‘local’ vertically integrated electric utilities. Each utility built sufficient generation to serve its own load responsibility. Transmission Interconnections with neighboring utilities were typically established for one of the following reasons:

1. To minimize duplication of transmission (i.e. tie to neighbor for transmission reliability instead of extending ‘local’ transmission system)
2. An economic decision to build transmission instead of generation based on the generation reliability criteria the utility planned for (i.e. tie to neighbor to facilitate emergency imports to meet generation reliability criteria).

This second reason is the origin of the CBM concept. Transmission interconnections provide each interconnected system with access to their neighbors so that in the event of an extreme generation outage within a utility, that temporarily generation deficient utility could have access to ‘emergency’ generation resources from their interconnected neighbors. CBM is the quantification of this use of the transmission system. Therefore, CBM is an ‘emergency’ use transmission quantity and only ‘exists’ on the importing system for use only during periods of an emergency generation deficiency when firm transmission service is not available (i.e. Firm ATC is insufficient to meet emergency import requirement). Just as transmission capacity is preserved for the transmission contingencies a utility planned for, transmission capacity is also preserved for the generation contingencies that are planned for. In either case, the utility customers paid for the transmission capacity that was installed to maintain the reliability level that is planned for, via their rates for service.

With the advent of RTOs, which result in essentially huge Control Areas/Transmission Service Providers, the amount of generation within the boundaries of these huge Transmission Providers is also increased – often by an order of magnitude. Although all RTOs operate the transmission system as one entity, the operational control of generation resources can vary among RTOs. Some RTOs also operate the generation as if it was one entity (i.e. a centralized dispatch) while in other RTOs each control area dispatches their own generation. As these larger organizations are created, the concept of CBM must be reexamined. For example, if two neighboring vertically integrated utilities combine (either by merger, or RTO membership), does the CBM between the previously ‘independent’ systems continue to ‘exist’ in the same manner as determined historically? Or is CBM re-determined for the larger organization, using the import capability from the sources external to the new larger organization? With the combination of utilities into RTO-type organizations, former transmission interconnections are internalized, rendering the issue: Does CBM continue to ‘exist’ **within** a larger organization, which historically was two or more independent utilities?

Although the concept of CBM existed since the establishment of interconnections, quantification of CBM was the result of Open Access required by FERC Order 888. The definition of CBM initially used was:

Previous Definition of CBM as per Available Transfer Capability Definition and Determination (NERC – 1996)

Capacity Benefit Margin (CBM) is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.

The CBM is a more locally applied margin than TRM, which is more of a network margin. As such, to the extent a load serving entity maintains policies and procedures to reserve transfer capability for generation reliability purposes, the CBM should be included in the reserved or committed system uses in the calculation of ATC. These CBMs should continue to be a consideration in transmission system development. It is anticipated that individual load serving entities and regional planning groups will continue to address CBMs and that the NERC and Regional reviews of generation adequacy will continue to consider this capability. It is also anticipated that load serving entities will develop additional procedures for reserving transfer capability for generation capacity purposes and include these procedures in Regional planning reviews and regulatory filings as appropriate.

The definition of CBM was refined based on a request by the NERC Planning Committee to establish a definition for CBM that all Regions agreed to. This new definition was then utilized as part of the development of the NERC Planning Standards. The current definition determined by the NERC ATCWG and agreed to by all Regions is:

Current Definition of CBM as per NERC Planning Standards (2001)

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

However, the definition currently in use still refers to CBM as an emergency import quantity and is silent of existence of CBM within or between parts of an RTO-type organization. If CBM does exist within an RTO-type organization, how are these internal quantities determined? How would this ‘internal’ CBM be used? If several formerly independent utilities combine into an RTO-type

LTATF Appendix on Redefinition Options for CBM

organization, can CBM continue to exist within this new larger organization? If so, how is a generation emergency within a portion of an RTO-type organization defined?

Redefinition options for CBM

Option 1: Retain the existing definition of CBM. The implication of retaining the existing definition is that CBM continues to be only an import quantity, and does not exist ‘within’ or ‘between’ geographical areas of an RTO-type footprint. If this concept is ratified, CBM would exist for RTOs only as import to the entire RTO footprint. Therefore the amount of CBM use would tend to be much smaller than currently. However, to the extent a generation deficiency within an RTO-type footprint was replaced with generation located elsewhere in the RTO, it would be considered a change in internal generation dispatch, and therefore be considered TRM.

Option 2: Change the definition to explicitly recognize CBM as applicable ‘within’ or ‘between’ geographical areas of an RTO-type footprint. For Example:

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

If Option 2 is accepted by the industry, several associated issues must be addressed;

1. How does the RTO-type organization determine the ‘subregions’ to calculate CBM? By load and or generation within an area? Historical company boundaries? Groupings of historical company boundaries? Other? How to develop without being arbitrary?
2. How does the CBM 'rights' of an LSE change when the footprint of the Transmission Service Provider changes?

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Standard Authorization Request Form

Title of Proposed Standard	Revision to Existing Standard Number MOD-001-0, MOD-002-0
Request Date	

SAR Requestor Information	SAR Type (Put an 'x' in front of one of these selections)	
Name LTATF	<input type="checkbox"/>	New Standard
Primary Contact Steve Dayney	x	Revision to existing Standard
Telephone Fax	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail	<input type="checkbox"/>	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

This request changes existing modeling standard(s) by adding a requirement for transmission providers to coordinate the calculation of ATC and requires that specific reliability practices be incorporated into the ATC calculation and coordination methodologies. Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity. This request adds a requirement for documentation of the methodologies used to coordinate ATC. In addition, a requirement is added for the enhanced documentation of the calculation methodology.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies by double clicking the grey boxes.)		
<input type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
<input type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules
<input type="checkbox"/>	Planning Authority	Plans the bulk electric system
<input type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input type="checkbox"/>	Transmission Owner	Owns transmission facilities
<input type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
<input type="checkbox"/>	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
<input type="checkbox"/>	Generator Owner	Owns and maintains generation unit(s)
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
<input type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
<input type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Pending resolution of the FMSCTF, might also apply to Transmission Planner and Planning Authority and Reliability Regions.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check boxes for all that apply by double clicking the grey boxes.)	
<input checked="" type="checkbox"/>	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage. Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Definitions of Terms used in standard:

Strawman Definitions:

The Drafting Team should finalize the definitions

Total Transfer Capability (TTC):

TTC and ATC are defined in standard 1E1

Existing Transmission Commitments (ETC)

ATC is expressed as:

ATC = TTC – Existing Transmission Commitments) – CBM – TRM

Flowgate is the name given to the transmission element(s) and associated contingency(ies) if any, that may limit transfer capability.

Flowgate Criteria – to be determined

Available Flowgate Capability (AFC)

AFC is expressed as:

AFC = [to be finalized by SARDT]

The relationship between ATC and AFC is as follows:

$ATC_{(Path\ A-B)} = AFC_{(Most\ Limiting\ Flowgate\ for\ Path\ A-B)} / Distribution\ Factor_{(Path\ A-B\ on\ Limiting\ Flowgate)}$

Daily, Monthly, Yearly TTC

Daily, Monthly, Yearly ATC

Daily, Monthly, Yearly TRM

Daily, Monthly, Yearly CBM

From existing standard, as recommend by LTATF

- Requirement 1 (R1). Each Region, RTO and ISO in conjunction with its members, shall develop and document a TTC and ATC (which may include the calculation of AFC) methodology.

If an RRO's members AFC, TTC and ATC values are determined by a RTO or ISO, then a Regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a Regional methodology.

Each transmission provider not associated with an RTO or ISO shall comply with the methodology developed by its respective reliability region.

(M1) This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

Each TTC and ATC methodology shall (S1):

- a) Include a narrative explaining how TTC and ATC values are determined and in evaluating a transmission service request and made available to customers. In addition, an explanation for all items listed here must also be included of any process that produces values that can override the TTC, AFC and ATC values.
- b) Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system, are included. An explanation must be provided on how reservations that exceed the capability of the specified source point are accounted for. (e.g. 500 MW of transmission service exists in each of three directions sourced from a generator with a capacity of 500 MW).
- c) Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations. Source and sink points are further defined in the Source and Sink Points white paper contained in Appendix B of the Final LTATF Report.
- d) Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)
- e) Require that ATC values and postings be updated at a minimum frequency to assure proper representation of the transmission system. These values will be made available to stakeholders at a similar frequency.
- f) Indicate the treatment and level of customer demands, including interruptible demands.
- g) Require that the data listed below, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used. Entities requiring data should request the data as needed. (SAR DT to determine to whom this applies, who supplies – who uses). In addition, specify how this information is coordinated and used to determine TTC and ATC values. If some data is not used or coordinated, provide an explanation. The required minimum update frequency¹ for each item is listed below:

¹ The update frequency specified should allow for improvements in technology, communication, etc, that might better represent actual system conditions.

1.1.1 **Generation Outage Schedules:** Minimum 13 month time frame includes all generators (SAR DT to determine MW threshold) used in the ATC/AFC calculation). The update frequency is daily.

1.1.2 **Generation dispatch order:** generic dispatch participation factors on a control area/market basis. The update frequency is as required.

1.1.3 **Transmission Outage Schedules:** Minimum 13 month time frame, updated daily for all bulk electric system facilities that impact ATC/AFC calculations; updated once an hour for unscheduled outages. (SAR DT should consider both pending and approved outages)

1.1.4 **Interchange Schedules :** The update frequency is hourly.

1.1.5 **Transmission Reservations:** The update frequency is daily.

1.1.6 **Load Forecast:** supplied via the SDX(or similar method), includes hourly data or peak with profile for the next 7-day time frame. The update frequency is daily. **In addition, daily peak for day 8 to 30 updated at least daily, and monthly for next 12 months updated monthly.**

1.1.7 **Flowgate AFC:** Firm and non-firm AFC values will be exchanged between entities that have coordination agreements. Unless otherwise specified in the coordination agreement, the minimum update frequency is as follows: Hourly AFC once-per-hour, Daily AFC once-per-day and Monthly AFC once-per-week.

1.1.8 Flowgate rating: Seasonal flowgate ratings will also be provided. Updated as required.

1.1.9 **Calculation model:** Updated model will be made available to neighboring/affected calculators.

1.1.10 Flowgates and flowgate definitions/criteria should be exchanged with neighboring/affected calculators on a seasonal basis, or more often as required to represent actual system conditions.

(SAR DT should discuss establishing defined criteria for establishing flowgates consistent with regional operating and planning practices)

h) Describe how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.

i) Describe assumptions used for positive impacts and counterflow of transmission reservations, including the basis for the assumptions.

k) Describe assumptions used for generation dispatch for both external and internal systems for base case dispatch and transaction modeling , including the basis for the assumptions.

l) Ensure that the TTC/ATC calculations are consistent with the Transmission Owner's/Transmission Planner's (leave FM designation to SAR DT) planning and operating criteria . (SAR DT see white paper dealing with consistency with planning criteria)

m) Describe the formal process for the RRO to grant any variances to individual transmission providers from the Regional TTC/ATC methodology.

- Any variances must also be approved by NERC or its designate

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

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

M3. (SDT to develop procedures for audit to ensure adherence to stated methodology)

Below is one suggested methodology from LTATF:

Each Region, in conjunction with its members, shall develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria. A review to verify that the ATC/TTC calculations are consistent with the TO's/TP's planning criteria is also required. RTOs and ISO will also be required to perform this review of consistency with planning criteria and document the results. The procedure used to verify the consistency must also be documented in the report. Documentation of the results of the most current reviews shall be provided to NERC within 30 Days of completion.

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

The RRO must review and approve the RTO or ISO ATC/TTC methodology to ensure it is consistent with the RRO's Planning and Operating Criteria.

The RRO or RTO/ISO is responsible for ensuring that TTC and ATC calculations are consistent with the individual TOs/TPs planning criteria.

Each procedure shall specify:

- a) The name, telephone number, and email address of a contact person to whom concerns are to be addressed.
- b) The amount of time it will take for a response.

- c) The manner in which the response will be communicated (e.g., email, letter, telephone, etc.)
- d) What recourse a customer has if the response is deemed unsatisfactory.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard Revision to Version Standards MOD 004, MOD005, MOD006, MOD 007, MOD 008, and MOD 009

Request Date

SAR Requestor Information	SAR Type (Put an 'x' in front of one of these selections)	
Name LTATF	<input type="checkbox"/>	New Standard
Primary Contact Steve Dayney	<input checked="" type="checkbox"/>	Revision to existing Standard
Telephone	<input type="checkbox"/>	Withdrawal of existing Standard
Fax		
E-mail	<input type="checkbox"/>	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

The LTATF passed the following strawman by a vote of 15 to 2:

Because the LTATF debated at length the merits of CBM calculation and utilization, the LTATF asks the SAR Drafting Team (SAR DT) to consider whether the calculation and/or withholding of CBM as an explicit quantity is necessary for reliability and should be part of a reliability standard. (please also see appendix F to the Final LTATF report)

If the industry still considers CBM to be necessary, the SAR DT is asked to consider the following recommendations:

If yes, then the existing standards on CBM should be revised to require crisp and clear documentation of the calculation of CBM and make various components of the methodology mandatory so there is more consistency across methodologies.

Additionally, the existing standards on TRM should be revised to require crisp and clear documentation of the calculation of TRM and make various components of the methodology mandatory so there is more consistency across methodologies.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies by double clicking the grey boxes.)		
<input type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
<input type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules
<input type="checkbox"/>	Planning Authority	Plans the bulk electric system
<input type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input type="checkbox"/>	Transmission Owner	Owens transmission facilities
<input type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
<input type="checkbox"/>	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
<input type="checkbox"/>	Generator Owner	Owens and maintains generation unit(s)
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
<input type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
<input type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Applicability to be determined by SAR DT.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check boxes for all that apply by double clicking the grey boxes.)	
<input checked="" type="checkbox"/>	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage. Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

M1. Each Region, RTO and ISO in conjunction with its members shall develop and document a CBM methodology. This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

If a RRO's members CBM values are determined by a RTO or ISO, then a Regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a Regional methodology.

Each transmission provider not associated with an RTO or ISO shall comply with the methodology developed by its respective reliability region. (S1)

Each CBM methodology shall (S1):

- a) Specify that the method used to determine generation reliability requirements as the basis for CBM shall be consistent with the respective generation planning criteria.
- b) Specify the frequency of calculation of the generation reliability requirement and associated CBM values.
 - Require that the calculations must be verified at least annually.
 - Require that the dates seasonal CBM values apply must be specified.
- c) Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system. SAR DT should discuss whether CBM should be an explicit reservation and how/if it would be made a requirement. Also, whether the reservations would be a business practice?
- d) Require that CBM be preserved only on the transmission provider's system where the load serving entity's load is located (i.e., CBM is an import quantity only). SAR DT should discuss whether there could be a reciprocal agreement for the use of CBM.
- e) Describe the inclusion or exclusion rationale in the CBM calculation for generation resources of each LSE including those generation resources not directly connected to the transmission provider's system but serving LSE loads connected to the transmission provider's system. The following rationale must be included in all methodologies:
 - All generation directly connected to the transmission provider's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.
 - The availability of generation not directly connected to the transmission provider's system being used to serve load directly connected to that system would be considered available per the terms under which it was arranged.

- f) Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system.. The following rationale must be included in all methodologies:
- The following units shall be included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined:
 - 1.Generation directly connected to the transmission provider's system but not obligated to serve load directly connected to that system, will be incorporated into the CBM requirement determination as follows:
 - a) Generation directly connected to the transmission provider's system, but committed to serve load on another system, will not be included in the CBM requirement determination for the transmission system to which the generator is directly connected.

(Note to SAR DT – Ensure that this would be consistent with any pending resource adequacy SAR.) These units are not included because they are committed to serve load on another system and therefore not available to serve load on the system for which the CBM requirement is being determined.)
 - b) Generation directly connected to the TSP's system, but not committed to serve load on any system, will be included in the CBM requirement determination for the transmission system to which the generator is directly connected as follows:
 1. The TSP will use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.
- g) Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.
- Require any variances must also be approved by NERC or its designate
- h) Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.
- i) Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).

j) Describe any adjustments to CBM values to account for generation reserve sharing arrangements (i.e. Use of CBM and a reserve sharing event simultaneously occurring that is not planned for). Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

SAR DT should consider paragraph below:

k) Require that CBM be based on the required or recommended planning reserve. In other words, a load serving entity that does not arrange for resources at least equal to the recommended or required planning reserve levels does not benefit by causing a higher CBM.

The SAR DT should consider the option below:

Require that the appropriate entities will plan and reinforce the transmission system for the amount of CBM being preserved.

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

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

- The RRO must review and approve the RTO or ISO methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO or RTO/ISO is responsible for ensuring that CBM calculations are consistent with the individual TOs planning criteria.
- SAR DT - Would the above be applicable to the Planning Authority?

The CBM review procedure shall:

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

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

The SAR DT should consider the option below:

- d) Require verification that the appropriate entities are planning and reinforcing the transmission system for the amount of CBM being preserved. The procedure must specify how the verification would be determined. RTOs and ISOs must also perform this verification and report on the findings as specified below.
- e) Require CBM values to be updated at least annually and available to the Regions, NERC, and stakeholders in the electricity markets.

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

Use of CBM

- Use of CBM should be addressed under business practices and not be part of this standard

TRM

M6. Each Region, RTO and ISO in conjunction with its members, shall develop and document a TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a RRO's members TRM values are determined by a RTO or ISO, than a Regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a Regional methodology. (S2) use same wording as above.

Each TRM methodology shall (S2):

- a) Specify the update frequency of TRM calculations.
 - Require that calculations be verified at least annually if determined to be required
 - Require that dates that seasonal TRM values apply must be specified
- b) Specify how TRM values are incorporated into ATC calculations.
- c) Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM: aggregate load forecast error (not included in determining generation reliability requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in

transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window). Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.

- Additional detail on how variations in generation dispatch are handled from intermittent generation sources such as wind and hydro, need to be provided

d) Describe the conditions, if any, under which TRM may be available to the market as non-firm transmission service.

e) Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional TRM methodology.

- Any variances must also be approved by NERC or its designate

f) Describe the methodology and conditions thereof that are used to reflect if TRM is reduced for the operating horizon,.

g) Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

SAR DT should consider paragraph below:

h) Specify TRM methodologies and values must be consistent with the approved planning criteria. Require that the appropriate entities will plan and reinforce the transmission system for the amount of TRM being preserved. The methodology must specify how the verification of the consistency would be determined.

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

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

The SAR DT should consider ways to ensure adherence with the paragraph below:

- The RRO must review and approve the RTO or ISO methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO or RTO/ISO is responsible for ensuring that TRM calculations are consistent with the individual TOs planning criteria.

The TRM review procedure shall:

- a) Indicate the frequency is at least annual, under which the verification review shall be implemented.

- b) Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to stakeholders.
- c) Require review of the consistency of the transmission provider's or Transmission Owner's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. RTOs and ISOs must also perform this review and report on the results. The review process used by a RTO or ISO also needs to be documented.
 - Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

SAR DT to review paragraph below:

- TRM methodologies and values must be consistent with the applicable planning criteria
- The methodology must specify how the verification of the consistency would be determined
- d) Require TRM values to be verified at least annually and made available to the Regions, NERC, and stakeholders.
- e) The documentation of the Regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC within 30 days of completion.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Instructions:

1. Please fill out as much of the requested information as possible. It is mandatory to provide a contact name, phone number and fax number to which questions can be directed. If you have an electronic mailing address, please make that available as well.
2. Attach any information you believe is related to the request. The more complete your request is, the less time is required to review it.
3. Once completed, send your request to:
Rae McQuade
NAESB, Executive Director
1301 Fannin, Suite 2350
Houston, TX 77002

Phone: 713-356-0060
Fax: 713-356-0067

by either mail, fax, or to NAESB's email address, naesb@naesb.org.

Once received, the request will be routed to the appropriate subcommittees for review.

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Date of Request: _____

1. Submitting Entity & Address:

__Long Term ATC/AFC Task Force_____

2. Contact Person, Phone #, Fax #, Electronic Mailing Address:

Name : __Steve Dayney_____
Title : _____
Phone : _____
Fax : _____
E-mail : _ltatf@nerc.com_____

3. Description of Proposed Standard or Enhancement:

It is proposed that a single Business Practice Standard be developed related to both:

- 1) the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM
- 2) the processing and evaluation of request(s) to schedule against approved transmission service reservation(s).

4. Use of Proposed Standard or Enhancement (include how the standard will be used, documentation on the description of the proposed standard, any existing documentation of the proposed standard, and required communication protocols):
 - a. The proposed standard will be applicable to transmission service providers to ensure that consistent practices are employed among transmission service providers when processing requests for transmission service,
 - b. The proposed standard will be applicable to transmission service providers to ensure that consistent scheduling practices are employed among transmission service providers, and
 - c. The proposed standard will be applicable to transmission service providers to ensure that details of the practices and procedures are available to market participants.

5. Description of Any Tangible or Intangible Benefits to the Use of the Proposed Standard or Enhancement:

Providing increased standardization of procedures and better informing market participants of these procedures would enhance market liquidity.

Additionally, this should result in better utilization of the transmission system.

6. Estimate of Incremental Specific Costs to Implement Proposed Standard or Enhancement:

t.b.d.

7. Description of Any Specific Legal or Other Considerations:

Development of this Business Practice needs to be closely coordinated with any work undertaken by NERC that impacts the calculation and coordination of AFC/ATC.

NERC's Long Term ATC/AFC TF (LTATF), which included NAESB participation, has identified a number of issues related to the calculation and coordination of ATC and AFC. Excerpts from the LTATF report are appended to the end of this document.

It is recommended that NAESB develop a Business Practice Standard that would ensure full disclosure as well as standardization where possible of the methodology by which Transmission Service Providers (TSPs):

- Determine the quantity of transmission service to be made available for sale to market participants; and
- Accept schedules for transmission previously purchased

In addition, in developing this methodology, each Transmission Service Provider TSP should, to the maximum extent possible:

- Use similar models and assumptions within equivalent operating timeframes;
- Use models and assumptions for the sale of transmission service that are similar to those used for the planning of the transmission system;
- Assure comparability of service for long term firm point to point and network service customers;
- Assure appropriate coordination between TSPs such that the sale of transmission service by one provider appropriately reflects the impacts on affected systems.

8. If This Proposed Standard or Enhancement Is Not Tested Yet, List Trading Partners Willing to Test Standard or Enhancement (Corporations and contacts):

N/A

9. If This Proposed Standard or Enhancement Is In Use, Who are the Trading Partners:

N/A

10. Attachments (such as : further detailed proposals, transaction data descriptions, information flows, implementation guides, business process descriptions, examples of ASC ANSI X12 mapped transactions):

Please see final Long Term AFC/ATC Task Force report on the NERC website at:
www.nerc.com (need to update with full URL when available)

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	ATC/TTC/AFC Revisions
Request Date	Revised June 16, 2005

SAR Requestor Information	SAR Type (Put an 'x' in front of one of these selections)	
Name (LTATF) Long Term AFC/ATC Task Force	<input type="checkbox"/>	New Standard
Primary Contact LTATF@nerc.com	<input checked="" type="checkbox"/>	Revision to existing Standard
Telephone Fax	<input type="checkbox"/>	Withdrawal of existing Standard
E-mail	<input type="checkbox"/>	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

This request changes existing modeling standard(s) by adding a requirement for transmission providers to coordinate the calculation of ATC and requires that specific reliability practices be incorporated into the ATC calculation and coordination methodologies. Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity. This request adds a requirement for documentation of the methodologies used to coordinate ATC. In addition, a requirement is added for the enhanced documentation of the calculation methodology.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies by double clicking the grey boxes.)		
<input type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
<input type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules
<input type="checkbox"/>	Planning Authority	Plans the bulk electric system
<input type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input type="checkbox"/>	Transmission Owner	Owens transmission facilities
<input type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
<input type="checkbox"/>	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
<input type="checkbox"/>	Generator Owner	Owens and maintains generation unit(s)
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
<input type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
<input type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Pending resolution of the FMSCTF, might also apply to Transmission Planner and Planning Authority and Reliability Regions.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check boxes for all that apply by double clicking the grey boxes.)	
<input checked="" type="checkbox"/>	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage. Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Definitions of Terms used in standard:

The Drafting Team should finalize the definitions for TTC, ATC, AFC.

The Drafting Team should finalize the criteria for determining flowgates

The Drafting Team should add a requirement for transmission providers to coordinate the calculation of ATC and require that specific reliability practices be incorporated into the ATC calculation and coordination methodologies.

The Drafting Team should add a requirement for the enhanced documentation of the ATC calculation methodology.

Strawman Definitions from LTATF are contained in the Appendix:

Additions/changes from existing standard in green, recommended by LTATF

B. Requirements

MOD-001-0 Requirement 1 (R1). Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region, shall jointly develop and document a TTC and ATC (which may include the calculation of AFC) methodology.

If the transmission service providers/and or AFC/ATC/TTC calculators' AFC, TTC and ATC values are determined by a RTO or ISO, then a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a jointly developed regional methodology.

Each transmission provider not associated with an RTO or ISO shall comply with the methodology jointly developed by the group of transmission service providers/and or AFC/ATC/TTC calculators within its respective reliability region.

This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

Each TTC and ATC methodology shall:

R1.1 Include a narrative explaining how TTC and ATC values are determined and in evaluating a transmission service request and made available to customers. In addition, an explanation for all items listed here must also be included of any process that produces values that can override the TTC, AFC and ATC values.

R1.2 Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system,

are included. An explanation must be provided on how reservations that exceed the capability of the specified source point are accounted for. (e.g. 500 MW of transmission service exists in each of three directions sourced from a generator with a capacity of 500 MW).

- R1.3 Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations. Source and sink points are further defined in the Source and Sink Points white paper contained in Appendix B of the Final LTATF Report.
- R1.4 Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)
- R1.5 Require that ATC values and postings be updated at a minimum frequency to assure proper representation of the transmission system. These values will be made available to stakeholders at a similar frequency.
- R1.6 Indicate the treatment and level of customer demands, including interruptible demands.
- R1.7 Require that the data listed below, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used. Entities requiring data should request the data as needed. (SAR DT to determine to whom this applies, who supplies – who uses). In addition, specify how this information is coordinated and used to determine TTC and ATC values. If some data is not used or coordinated, provide an explanation. The required minimum update frequency¹ for each item is listed below:
- R1.7.1 **Generation Outage Schedules:** Minimum 13 month time frame includes all generators (SAR DT to determine MW threshold) used in the ATC/AFC calculation). The update frequency is daily.
 - R1.7.2 **Generation dispatch order:** generic dispatch participation factors on a control area/market basis. The update frequency is as required.
 - R1.7.3 **Transmission Outage Schedules:** Minimum 13 month time frame, updated daily for all bulk electric system facilities that impact ATC/AFC calculations; updated once an hour for unscheduled outages. (SAR DT should consider both pending and approved outages)
 - R1.7.4 **Interchange Schedules :** The update frequency is hourly.

¹ The update frequency specified should allow for improvements in technology, communication, etc, that might better represent actual system conditions.

R1.7.5 Transmission Reservations: The update frequency is daily.

R1.7.6 Load Forecast: supplied via the SDX(or similar method), includes hourly data or peak with profile for the next 7-day time frame. The update frequency is daily. In addition, daily peak for day 8 to 30 updated at least daily, and monthly for next 12 months updated monthly.

R1.7.7 Flowgate AFC: Firm and non-firm AFC values will be exchanged between entities that have coordination agreements. Unless otherwise specified in the coordination agreement, the minimum update frequency is as follows: Hourly AFC once-per-hour, Daily AFC once-per-day and Monthly AFC once-per-week.

R1.7.8 Flowgate rating: Seasonal flowgate ratings will also be provided. Updated as required.

R1.7.9 Calculation model: Updated model will be made available to neighboring/affected calculators.

R1.7.10 Flowgates and flowgate definitions/criteria should be exchanged with neighboring/affected calculators on a seasonal basis, or more often as required to represent actual system conditions.

(SAR DT should discuss establishing defined criteria for establishing flowgates consistent with regional operating and planning practices)

R1.8 Describe how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.

R1.9 Describe assumptions used for positive impacts and counterflow of transmission reservations, including the basis for the assumptions.

R1.10 Describe assumptions used for generation dispatch for both external and internal systems for base case dispatch and transaction modeling, including the basis for the assumptions.

R1.11 Ensure that the TTC/ATC calculations are consistent with the Transmission Owner's/Transmission Planner's (leave FM designation to SAR DT) planning and operating criteria. (SAR DT: see Appendix E of final LTATF report dealing with consistency with planning criteria)

R1.12 Describe the formal process for the granting of any variances to individual transmission providers from the jointly developed regional TTC/ATC methodology.
➤ Any variances must be approved by NERC or its designate

R2. The most recent version of the documentation of each TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the stakeholders in the electricity market.

R3. Each TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.

C. Measures.

M1. The Regional Reliability Organization shall provide evidence that its most recent TTC and ATC methodology documentation meets Reliability Standard MOD-001-0_R1.

M2. The Regional Reliability Organization shall provide evidence that its TTC and ATC methodology is available on a web site accessible by NERC, the Regional Reliability Organizations, and transmission users.

(SDT to develop procedures for audit to ensure adherence to stated methodology)

Moved to appendix per suggestion from SAC

a)

Related Standards

Standard No.	Explanation
MOD-002-0	Review of TTC and ATC Calculations and Results

Related SARs

SAR ID	Explanation
T.B.D	LTATF SAR for TRM and CBM (submitted with this SAR)
R05004	NAESB proposed Business Practice for a single Business Practice Standard to be developed related to both: 1) the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM 2) the processing and evaluation of request(s) to schedule against approved transmission service reservation(s).

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

Appendix

Strawman Definitions from LTATF:

Total Transfer Capability (TTC):

TTC and ATC are defined in standard 1E1

Existing Transmission Commitments (ETC)

ATC is expressed as:

ATC = TTC – Existing Transmission Commitments) – CBM – TRM

Flowgate is the name given to the transmission element(s) and associated contingency(ies) if any, that may limit transfer capability.

Flowgate Criteria – to be determined by SDT

Available Flowgate Capability (AFC)

AFC is expressed as:

AFC = [to be finalized by SARDT]

The relationship between ATC and AFC is as follows:

$ATC_{(Path\ A-B)} = AFC_{(Most\ Limiting\ Flowgate\ for\ Path\ A-B)} / Distribution\ Factor_{(Path\ A-B\ on\ Limiting\ Flowgate)}$

Daily, Monthly, Yearly TTC

Daily, Monthly, Yearly ATC

Daily, Monthly, Yearly TRM

Daily, Monthly, Yearly CBM

LTATF Suggested Audit Methodology

M1. Each group of transmission service providers within a region, in conjunction with the members of that region, shall jointly develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria.

M2. A review to verify that the ATC/TTC calculations are consistent with the TO's/TP's planning criteria is also required. The procedure used to verify the consistency must also be documented in the report. Documentation of the results of the most current reviews shall be provided to NERC within 30 Days of completion.

M3. Each entity responsible for the TTC and ATC methodology, in conjunction with its members and stakeholders, shall have and document a procedure on how stakeholders can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be

addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the stakeholders in the electricity market.

M4. The RRO must review and approve the ATC/TTC methodology to ensure it is consistent with the RRO's Planning and Operating Criteria.

The RRO is responsible for ensuring that TTC and ATC calculations are consistent with the individual TOs/TPs planning criteria.

Each procedure shall specify:

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

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	CBM/TRM Revisions
Request Date:	revised June 16, 2005

SAR Requestor Information	SAR Type (Put an 'x' in front of one of these selections)	
Name (LTATF)	Long Term AFC/ATC Task Force	<input type="checkbox"/> New Standard
Primary Contact	ltatf@nerc.com	<input checked="" type="checkbox"/> Revision to existing Standard
Telephone Fax		<input type="checkbox"/> Withdrawal of existing Standard
E-mail		<input type="checkbox"/> Urgent Action

Purpose/Industry Need (Provide one or two sentences)

The existing standards on TRM should be revised to require crisp and clear documentation of the calculation of TRM and make various components of the methodology mandatory so there is more consistency across methodologies.

NOTE: the LTATF passed the following strawman by a vote of 15 to 2:

Because the LTATF debated at length the merits of CBM calculation and utilization, the LTATF asks the SAR Drafting Team (SAR DT) to consider whether the calculation and/or withholding of CBM as an explicit quantity is necessary for reliability and should be part of a reliability standard. (please also see appendix F to the Final LTATF report)

If however, the industry still considers CBM to be necessary, the SAR DT is asked to consider the following recommendations:

The existing standards on CBM should be revised to require crisp and clear documentation of the calculation of CBM and make various components of the methodology mandatory so there is more consistency across methodologies.

Reliability Functions

The Standard will Apply to the Following Functions (Check box for each one that applies by double clicking the grey boxes.)		
<input type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
<input type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules
<input type="checkbox"/>	Planning Authority	Plans the bulk electric system
<input type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
<input type="checkbox"/>	Transmission Owner	Owns transmission facilities
<input type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
<input type="checkbox"/>	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
<input type="checkbox"/>	Generator Owner	Owns and maintains generation unit(s)
<input type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
<input type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
<input type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Applicability to be determined by SAR DT.

Reliability and Market Interface Principles

Applicable Reliability Principles (Check boxes for all that apply by double clicking the grey boxes.)	
<input checked="" type="checkbox"/>	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input type="checkbox"/>	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input type="checkbox"/>	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? (Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage. Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

LTATF proposed changes are highlighted in green

SUGGESTED REVISIONS to MOD-004-0

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region shall jointly develop and document a CBM methodology. This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

If a RRO's members CBM values are determined by a RTO or ISO, then a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a jointly developed regional methodology.

Each transmission provider not associated with an RTO or ISO shall comply with the methodology jointly developed within its respective reliability region.

Each CBM methodology shall (S1):

R1.1 Specify that the method used to determine generation reliability requirements as the basis for CBM shall be consistent with the respective generation planning criteria.

R1.2 Specify the frequency of calculation of the generation reliability requirement and associated CBM values.

- Require that the calculations must be verified at least annually.
- Require that the dates seasonal CBM values apply must be specified.

R1.3 Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.

SAR DT should discuss whether CBM should be an explicit reservation and how/if it would be made a requirement. Also, whether the reservations would be a business practice?

R1.4 Require that CBM be preserved only on the transmission provider's system where the load serving entity's load is located (i.e., CBM is an import quantity only).

SAR DT should discuss whether there could be a reciprocal agreement for the use of CBM.

R1.5 Describe the inclusion or exclusion rationale in the CBM calculation for generation resources of each LSE including those generation resources not directly connected to the transmission provider's system but serving LSE loads connected to the transmission provider's system. The following rationale must be included in all methodologies:

R1.5.1 All generation directly connected to the transmission provider's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.

R1.5.2 The availability of generation not directly connected to the transmission provider's system being used to serve load directly connected to that system would

be considered available per the terms under which it was arranged.

R1.6 Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system but not obligated to serve Native/Network Load connected to the TSP's system. The following rationale must be included in all methodologies:

R1.6.1 The following units shall be included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined:

i. Generation directly connected to the transmission provider's system but not obligated to serve load directly connected to that system, will be incorporated into the CBM requirement determination as follows:

1. Generation directly connected to the transmission provider's system, but committed to serve load on another system, will not be included in the CBM requirement determination for the transmission system to which the generator is directly connected. **(Note to SAR DT – Ensure that this would be consistent with any pending resource adequacy SAR.) These units are not included because they are committed to serve load on another system and therefore not available to serve load on the system for which the CBM requirement is being determined.)**

2. Generation directly connected to the TSP's system, but not committed to serve load on any system, will be included in the CBM requirement determination for the transmission system to which the generator is directly connected as follows:

The TSP will use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.

R1.4 Describe the formal process and rationale for the RRO to grant any variances to individual transmission providers from the Regional CBM methodology.

R1.6.1 Require any variances must also be approved by NERC or its designate.

R1.5 Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.

R1.6 Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain

conditions).

R1.7 Describe any adjustments to CBM values to account for generation reserve sharing arrangements (i.e. Use of CBM and a reserve sharing event simultaneously occurring that is not planned for). Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

SAR DT should consider paragraph below:

R1.8 Require that CBM be based on the required or recommended planning reserve. In other words, a load serving entity that does not arrange for resources at least equal to the recommended or required planning reserve levels does not benefit by causing a higher CBM.

The SAR DT should consider the option below:

R1.9 Require that the appropriate entities will plan and reinforce the transmission system for the amount of CBM being preserved.

R2. The RRO's most recent version of the documentation of each entity's CBM methodology shall be available on a web site accessible by NERC, the RROs, and the stakeholders in the electricity market.

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

- The RRO must review and approve the TSP methodology to ensure it is consistent with the RRO's Planning Criteria. The TSP is responsible for ensuring that CBM calculations are consistent with the individual TOs planning criteria.

Question for SAR DT - Would the above be applicable to the Planning Authority?

REVISIONS to MOD-005-0

R1. Each Regional Reliability Organization, in conjunction with its members, shall develop and implement a procedure to review (at least annually) the CBM calculations and the resulting values of member Transmission Service Providers to ensure that they comply with the Regional Reliability Organization's CBM methodology. The CBM review procedure shall include the following four requirements:

- R1.1 Indicate the frequency **is at least annual**, under which the verification review shall be implemented.
- R1.2 Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to **stakeholders**.
- R1.3 Require review of the consistency of the transmission provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the **same** components that comprise CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. **It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. The procedure must specify how the consistency would be verified.**

The SAR DT should consider the options below:

R1.3.1 Require verification that the appropriate entities are planning and reinforcing the transmission system for the amount of CBM being preserved. The procedure must specify how the verification would be determined. Transmission service providers must also perform this verification and report on the findings as specified below.

- R1.4 Require CBM values to be updated **at least annually** and available to the Regions, NERC, and **stakeholders in the electricity markets**.

R2. The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days).

R3. Documentation of the results of the most current implementation of the procedure shall be sent to NERC within 30 days of completion.

REVISIONS to MOD-006-0

Note to SAR DT: Use of CBM should be addressed under business practices and not be part of this standard - consider the withdrawal of MOD-006-0 and transfer to NAESB.

REVISIONS to MOD-008-0

R1. Each **group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region in conjunction with its members, shall jointly develop and document a TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a RRO's members TRM values are determined by a RTO or ISO, than a jointly developed regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to**

have a regional methodology.

Each TRM methodology shall:

- R1.1 Specify the update frequency of TRM calculations.
 - Require that calculations be verified at least annually if determined to be required
 - Require that dates that seasonal TRM values apply must be specified
- R1.2 Specify how TRM values are incorporated into ATC calculations.
- R1.3 Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values. The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM:
 - R1.3.1 aggregate load forecast error (not included in determining generation reliability requirements).
 - R1.3.2 load distribution error.
 - R1.3.3 variations in facility loadings due to balancing of generation within a Balancing Authority Area.
 - R1.3.4 forecast uncertainty in transmission system topology.
 - R1.3.5 allowances for parallel path (loop flow) impacts.
 - R1.3.6 allowances for simultaneous path interactions.
 - R1.3.7 variations in generation dispatch
 - R1.3.8 short-term operator response (operating reserve actions not exceeding a 59-minute window).
 - R1.3.9 Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.
 - R1.3.10 Additional detail on how variations in generation dispatch are handled from intermittent generation sources such as wind and hydro, need to be provided.
- R1.4 Describe the conditions, if any, under which TRM may be available to the market as Non-Firm Transmission Service.
- R1.5 Describe the formal process for the granting of any variances to individual transmission service providers from the regional TRM methodology.
 - R1.5.1 Any variances must also be approved by NERC or its designate
- R1.6 Describe the methodology and conditions thereof that are used to reflect if TRM is reduced for the operating horizon.
- R1.7 Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

SAR DT should consider paragraph below:

- R1.8 Specify TRM methodologies and values must be consistent with the approved

planning criteria.

R1.8.1 Require that the appropriate entities will plan and reinforce the transmission system for the amount of TRM being preserved. The methodology must specify how the verification of the consistency would be determined.

R1.8.2 Each TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are entity specific or that are considered in each respective methodology shall also be explained along with their use in determining TRM values.

REVISIONS to MOD-009-0

R1. Each group of transmission service providers/and or AFC/ATC/TTC calculators within a region, in conjunction with the members of that region, in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and resulting values of member transmission providers to ensure that they comply with the regional TRM methodology and are updated at least annually and available to transmission users.

The SAR DT should consider ways to ensure adherence with the paragraph below:

- The RRO must review and approve the transmission service provider(s)' methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO is responsible for ensuring that TRM calculations are consistent with the individual TOs planning criteria.

The TRM review procedure shall:

- R1.1 Indicate the frequency is at least annual, under which the verification review shall be implemented.
- R1.2 Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to stakeholders.
- R1.3 Require review of the consistency of the transmission service provider's or Transmission Owner's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process. The review process used by a transmission service provider or transmission owner also needs to be documented.
- R1.3.1 Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

SAR DT to review paragraph below:

R1.4 TRM methodologies and values must be consistent with the applicable planning criteria

➤ The methodology must specify how the verification of the consistency would be determined

R2. The documentation of the regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC within 30 days of completion.

R3. Documentation of the results of the most current regional reviews shall be provided to NERC within 30 days of completion.

R4. Require TRM values to be verified at least annually and made available to the RROs, NERC, and stakeholders.

Related Standards

Standard No.	Explanation
t.b.d	LTATF SAR for ATC and TTC (submitted with this SAR).
R05004	NAESB proposed Business Practice for a single Business Practice Standard to be developed related to both: 1) the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM 2) the processing and evaluation of request(s) to schedule against approved transmission service reservation(s).

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

Attachment 8

111 FERC ¶ 61,274
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 37

[Docket No. RM05-17-000]

Information Requirements for Available Transfer Capability

(May 27, 2005)

AGENCY: Federal Energy Regulatory Commission

ACTION: Notice of Inquiry

SUMMARY: The Federal Energy Regulatory Commission seeks comments on:

(a) the North American Electric Reliability Council's recent Long-Term AFC/ATC Task Force Report; (b) the advisability of revising and standardizing available transfer capability calculations; and (c) the most expeditious way to obtain an industry-wide standard for available transfer capability calculations.

This Notice of Inquiry is the result of a review conducted by the Commission's Information Assessment Team (FIAT), to propose: (a) new information the Commission needs to promote greater market transparency in electricity markets; and (b) ways to reduce the reporting burden on industry through the elimination, reduction, streamlining or reformatting of current information collections.

DATES: Comments on this Notice of Inquiry are due on [Insert date 60 days after publication in the FEDERAL REGISTER].

ADDRESSES: Comments may be filed electronically via the eFiling link on the Commission's web site at <http://www.ferc.gov>. Commenters unable to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street N.E., Washington, DC, 20426. Refer to the Comment Procedures section of the preamble for additional information on how to file comments.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Information Requirements for
Available Transfer Capability

Docket No. RM05-17-000

NOTICE OF INQUIRY

(May 27, 2005)

1. In Order No. 889,¹ the Commission required transmission providers² to offer unused transmission capacity to the market by posting available transfer capability (ATC) on their Open Access Same-Time Information Systems

¹ *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, 61 FR 21,737 (1996), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, 62 FR 12,484 (1997), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,049 (1997), *reh'g denied*, Order No. 889-B, 81 FERC ¶ 61,253 (1997).

² A transmission provider is the public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff. *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles January 1991-June 1996 ¶ 31,036 Appendix D (Pro Forma Tariff) at 1.46 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12,274 (March 4, 1997), FERC Stats. & Regs., Regulations Preambles July 1996-December 2001 ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) (Order No. 888).

(OASIS).³ In the years since the Commission issued Order No. 889, market participants have complained that variations in the way ATC is calculated provide opportunities for undue discrimination and create obstacles to doing business. The Commission believes that standardizing the way ATC is calculated will alleviate these obstacles. This Notice of Inquiry is the result of a review conducted by the Commission's Information Assessment Team (FIAT), to propose: (1) new information the Commission needs to promote greater market transparency in electricity markets; and (b) ways to reduce the reporting burden on industry through the elimination, reduction, streamlining or reformatting of current information collections.

2. The Commission has reviewed the final report of the North American Electric Reliability Council (NERC) on long-term available flowgate capability (AFC) and ATC,⁴ which addresses the calculation and coordination of AFC/ATC to increase market liquidity and enhance reliability. As discussed more fully below, NERC's LTATF Report provides useful guidance on how to achieve an industry-wide methodology for calculating ATC. The Commission encourages the electricity industry to work toward standardization and coordination of ATC and

³ 18 CFR Part 37.

⁴ North American Electric Reliability Council, *Long-Term AFC/ATC Task Force Final Report* (2005) (LTATF Report).

related terms, and requests comments on the recommendations put forth in the LTATF Report.⁵

Background

A. Definitions

3. The calculation of ATC involves a number of variables that require definition. The Commission will use the LTATF Report definitions for purposes of the discussion in this Notice of Inquiry. The Commission requests, however, that the industry comment on these definitions, as these variables determine the calculation of ATC.

4. For market participants, ATC is essentially a measure of unused transmission that a transmission provider can offer for sale pursuant to Order Nos. 888 and 889. Transmission providers sell transmission service to customers in the form of transfer capability. Transfer capability is the measure of the ability of the interconnected electrical system to move electric energy reliably from one point to another and is limited by, among other things, the capacity either of equipment (such as transformers or transmission circuits) or interfaces (one or more circuits). ATC is the amount of transfer capability still available for sale after all existing uses are accounted for.⁶ Transmission providers calculate ATC

⁵ The Commission recognizes the common interest of the United States, Canada and Mexico in maintaining a safe and reliable interconnected North American bulk power system. Any standards promulgated by the Commission would apply only to jurisdictional entities.

⁶ LTATF Report, Appendix A, page 4.

by subtracting existing transmission commitments, transmission reserve margin, and capacity benefit margin from total transfer capability.⁷

5. A flowgate is the name given to a transmission element(s) and associated contingencies that may limit ATC. AFC is a measure of the capability remaining on a flowgate for future uses, after considering the effect of prior sales. AFC is measured as a flow limit on a flowgate, while ATC is measured as a transaction limit from a source to a sink.⁸

6. There may be multiple flowgates between source and sink that can limit a transaction. If the assumptions that underlie AFC and ATC do not reasonably conform to real-time operations, the transmission system will either be artificially constrained, or it will be underused, leading to lost transmission opportunities.

7. Transmission providers use CBM and TRM in their ATC and AFC calculations to account for uncertainties or contingencies that are not explicitly modeled in the calculations. CBM is the amount of firm transmission transfer capability reserved by the transmission provider so that load serving entities, whose loads are located on that transmission provider's system, can access remote reserve generation from interconnected systems.⁹ TRM is the amount of

⁷ ATC equals Total Transfer Capability (TTC) minus Existing Transmission Commitments (ETC) minus Transmission Reserve Margin (TRM) minus Capacity Benefit Margin (CBM), or $ATC = TTC - ETC - TRM - CBM$.

⁸ "Source" and "sink" are points at which the transmission of electric energy begins (source) and ends (sink).

⁹ LTATF Report, Appendix F, page 2.

transmission transfer capability necessary to ensure that the interconnected transmission network will be secure under a reasonable range of uncertainties in system conditions. The criteria used to determine TRM and CBM should be consistent with the transmission operator's planning and operating criteria.¹⁰

B. Evolution of Electricity Markets since Order Nos. 888 and 889

8. In Order Nos. 888 and 889, the Commission required transmission providers to sell unused transmission capacity and post their ATC on OASIS. Market transactions depend on this critical transmission information. As the electric industry has evolved, the nature of the calculations of ATC, TTC, TRM and CBM and the interaction between neighboring transmission providers has changed substantially. In the years since the Commission established OASIS, independent system operators (ISOs) and regional transmission organizations (RTOs) have developed organized markets. Agreements among neighboring ISOs/RTOs and transmission service providers have led to increased coordination of operation and requests for transmission service, and have resulted in fewer variations in the calculation of ATC for those regions. In regions without an ISO/RTO, however, this may not be the case.

9. While the electric industry uses OASIS for posting ATC, there is as yet no industry-wide standard for calculating ATC. The Commission's OASIS II Advanced Notice of Proposed Rulemaking, issued in July 2000, contemplated

¹⁰ *Id.* at Appendix A, page 5.

detailed, standard communication protocols and associated business practices for ATC, TTC, and CBM¹¹ but these standards and protocols are not yet in place.

C. Problems with ATC Calculations

10. Transmission providers have incentives to understate ATC on those paths valuable to power sellers that are competitors to a transmission provider's own (or its affiliate's) power sales. The lack of clear and consistent methodologies for calculating ATC can allow transmission providers the discretion to control the transmission system to favor their own power sales or those of their affiliates. ATC can vary considerably depending on the criteria they use to calculate it and the order in which the calculations are made. Although the Commission has required transmission providers to post the formula for calculating ATC,¹² the transmission provider has sole responsibility for, and a great deal of discretion in, its calculation. More rigorous and consistent standards and procedures for ATC calculations would help ensure that transmission providers' exercise of discretion in their calculation of ATC does not result in undue discrimination with respect to interstate transmission.

11. Complainants have alleged that transmission providers misrepresent ATC, often using ATC calculations to inflate transmission needed to serve native load or to set aside capacity for their affiliates. In one instance, a transmission provider

¹¹ *Open Access Same-Time Information System Phase II*, 92 FERC ¶61,047 at 61,126-27 (2000).

¹² 18 CFR 37.6.

reserved capacity on behalf of native load but failed to designate network resources as required by the open access transmission tariff. The company thus improperly increased the existing transmission commitment component of the ATC calculation, artificially reducing posted ATC.¹³ It is thus important that the ATC component (TRM and CBM) assumptions are stated and posted so that recalculated ATC values are transparent and not devised to produce an unduly discriminatory result.

12. The lack of standardization and coordination of ATC can not only result in unduly discriminatory behavior, but can also on occasion affect reliability. As the LTATF recognized, inaccurate ATC values can lead to Transmission Loading Relief actions [or curtailments in the Western Electricity Coordinating Council (WECC)] if they result in transmission flows that exceed line limits.¹⁴ In this regard, preceding the August 14, 2003 blackout, transmission operators calculated ATC values approximately seven days ahead using forecasted system conditions. This lag in real-time ATC values contributed to the blackout. The Final Blackout Report indicated that transmission operators should update ATC/TTC values as the forecast of system conditions changes.¹⁵

¹³ See *Aquila Power Corporation v. Entergy Services, Inc.*, 90 FERC ¶ 61,260 at 61,859-60 (2000).

¹⁴ LTATF Report, page 1.

¹⁵ U.S.-Canada Power System Outage Task Force, *Final Report on the August 14th Blackout in the United States and Canada: Causes and Recommendations* 31 (April 2004) (Final Blackout Report).

D. The LTATF Report

13. NERC created the LTATF to develop a report and specific recommendations for the calculation and coordination of AFC/ATC to increase market liquidity and enhance reliability. NERC's Market Committee directed the LTATF efforts and the LTATF also coordinated its efforts with representatives from the North American Energy Standards Board (NAESB). The LTATF Report builds upon NERC's "Version 0" reliability standards, which the Commission incorporated into its Policy Statement on Matters Related to Bulk Power System Reliability in February 2005.¹⁶ The Version 0 reliability standards attempt to state reliability goals clearly and provide a means by which to measure the progress toward their attainment. The Commission's Supplement to the Policy Statement makes clear that the term Good Utility Practice as used in the open access transmission tariff (OATT) includes compliance with NERC's Version 0 reliability standards.¹⁷

14. The LTATF Report outlines existing ATC practices in the Eastern Interconnection and the WECC. It also proposes a method of exchanging AFC/ATC data between entities and summarizes the minimum requirements of

¹⁶ *Supplement to Policy Statement on Matters Related to Bulk Power System Reliability*, 110 FERC ¶61,096 (2005) (*Supplement*); see *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 (*Policy Statement*), *clarified*, 108 FERC ¶61,288 (2004).

¹⁷ *Supplement* at P 23. Version 0 Standards MOD 001-0 through 009-0 are specifically relevant here.

modeling techniques to facilitate proper calculation and coordination of AFC/ATC.

15. The LTATF Report details three groups of issues: (1) communication and coordination of AFC/ATC; (2) calculation process for AFC/ATC; and (3) consistency between planning criteria and the attributes of AFC/ATC calculations (over both planning and operating horizons).

Communication and coordination of AFC/ATC—respecting third party constraints

16. The objective of AFC/ATC coordination is to ensure that neighboring entities exchange relevant information to facilitate: (a) a reasonable representation of external entities for modeling purposes; (b) the ability of each calculator¹⁸ to adequately represent the values of flowgates on third party transmission systems; and (c) the ability of each calculator to translate data from neighboring entities and make meaningful use of the data in its calculations.

17. The LTATF documented the existing coordination processes for the major regions in the Eastern Interconnection and the WECC. The report proposes a method of exchanging AFC/ATC data between entities and provides the minimum requirements for flowgate exchange and modeling techniques needed to ensure proper calculation and coordination of transfer capability.

¹⁸ The calculator prepares and updates ATC values for the transmission provider.

Calculation process for AFC/ATC

18. The LTATF agreed that transmission service providers need to provide better documentation and greater transparency for their AFC/ATC calculation processes. The LTATF Report contains a number of recommendations to achieve more consistency among AFC/ATC calculations.

19. The LTATF proposed a Standard Authorization Request (SAR) that contains recommendations to achieve more consistency among AFC/ATC calculations. The SAR would change the existing modeling standard(s) by adding a requirement for transmission providers to coordinate the calculation of ATC and incorporate specific reliability practices into the ATC calculation and coordination methodologies.¹⁹

20. The LTATF found that the way in which various regions calculate and use ATC, TTC, TRM and CBM varies widely.²⁰ As the LTATF Report explains, some transmission providers first calculate TTC, and then derive ATC. Others first calculate ATC, and then derive TTC. Some transmission providers first calculate AFC, and then derive ATC. Some only calculate TTC. Some transmission providers use CBM; some do not use CBM. The scope of CBM varies by footprint. Nearly all transmission providers use TRM.²¹

¹⁹ LTATF Report, Attachment A, SAR-1.

²⁰ LTATF Report at page 3.

²¹ *Id.* at page 2. The LTATF reviewed ATC methodologies and found that the numerous ATC calculators in the Midwest have been replaced by the Midwest Independent Transmission System Operator and the PJM Interconnection, LLC.

21. The LTATF noted that consistency is important in the calculation of CBM and TRM and recommended revising applicable standards. The LTATF proposed a SAR to modify the current methodology for calculating CBM and TRM.²²

22. The LTATF also used the LTATF Report and recommendations to develop a proposed NAESB business practice standard. The LTATF Report proposes that a single business practice standard be developed related to both: (a) the processing and evaluation of transmission service requests which use TTC/ATC/AFC and CBM/TRM; and (b) the processing and evaluation of requests to schedule against approved transmission service reservations.²³

Consistency between planning criteria and the attributes of the AFC/ATC calculations (over both planning and operating horizons)

23. The LTATF emphasized that the assumptions used in the calculation of AFC/ATC and CBM/TRM should be consistent with those used in the planning and operating horizons. The LTATF noted that transmission service providers should document these calculations and make them transparent to all who use the transmission network.²⁴

24. The LTATF suggested that transmission providers ensure consistency between their ATC calculations and their internal planning processes. For

The LTATF found 50 to 60 ATC calculators nationwide, with most of those in the West (30 to 40). *Id.* at page 3.

²² *Id.* at Attachment B, SAR-1.

²³ *Id.* at Attachment C, page 2.

²⁴ *Id.* at page 3.

example, the LTATF recommended that both the internal planning processes and the ATC calculations reflect the same counterflows and the same components of TRM. Discrepancies between the internal planning processes and ATC calculations can result in inaccurate calculations of transmission available to the market.²⁵

Discussion

25. As noted above, problems in the way AFC and ATC are calculated can create and have created obstacles to ensuring that the provision of interstate transmission service is not unduly discriminatory or preferential. **The**

Commission believes that standardizing the way AFC and ATC are calculated will help mitigate this potential, and enhance system performance.

26. The LTATF Report contains proposals that appear to go a long way toward refining and standardizing these calculations. By developing a business practice standard and revisions related to reliability standards, the LTATF Report would also take such calculations beyond NERC's Version 0 reliability standards.

27. NERC also has long encouraged regions to promote a common methodology for determining TRM and CBM.²⁶ Appendix C to the LTATF Report²⁷ recommends that the regions adopt written regional methodologies for

²⁵ *Id.* at, Appendix E, page 2.

²⁶ See North American Electric Reliability Council, *Transmission Capability Margins and Their Use in ATC Determination 3* (1999).

²⁷ Appendix C is entitled: Review of Current NERC Standards on CBM and TRM.

calculating CBM and TRM. The LTATF Report also sets forth areas in which CBM and TRM standards could be more specific. The Commission requests comments on these recommendations and whether they go far enough in promoting a common TRM and CBM methodology within each region. The Commission also invites comments on whether there should be common TRM and CBM methodologies among regions.

28. More specifically, the Commission seeks industry comment on: (a) the definitions of AFC, ATC, CBM and TRM used in this order; (b) the advisability of revising and standardizing AFC, ATC, TRM and CBM values; (c) the advisability of developing interconnection-wide standards for the Eastern Interconnection and the WECC; (d) the contents of the LTATF Report; and (e) the most expeditious way to obtain industry-wide standards for ATC calculations.

29. While the LTATF Report is a start, the Commission recognizes that more work is needed before there can be industry-standard AFC and ATC calculations. The Commission notes that the LTATF coordinated its efforts with NAESB and applauds NERC's efforts to work with NAESB in developing comprehensive business practice and reliability standards. The Commission urges that these efforts continue.

Comment Procedures

30. The Commission invites interested persons to submit comments on these matters and any related matters or alternative proposals that commenters may wish to discuss. Comments are due **[insert date 60 days after publication in the**

FEDERAL REGISTER]. Comments must refer to Docket No. RM05-17-000, and must include the commenter's name, the organization they represent, if applicable, and their address.

31. Comments may be filed electronically via the eFiling link on the Commission's web site at <http://www.ferc.gov>. The Commission accepts most standard word processing formats and commenters may attach additional files with supporting information in certain other file formats. Commenters filing electronically do not need to make a paper filing. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: The Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street N.E., Washington, DC, 20426.

32. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters commenting on this proposal are not required to serve copies of their comments on other commenters.

Document Availability

33. In addition to publishing the full text of this document in the *Federal Register*, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through Commission's Home Page (<http://www.ferc.gov>) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

34. From the Commission's Home Page on the Internet, this information is available in its eLibrary. The full text of this document is available in the eLibrary both in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

35. User assistance is available for eLibrary and the Commission's website during normal business hours. For assistance contact FERC Online Support at FERCOnlineSupport@ferc.gov or toll-free at (866)208-3676, or for TTY, contact (202) 502-8659. E-Mail the Public Reference Room at public.referenceroom@ferc.gov or (202) 502-8371.

By direction of the Commission.

Linda Mitry,
Deputy Secretary.

R05007

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction

Instructions:

1. Please fill out as much of the requested information as possible. It is mandatory to provide a contact name, phone number and fax number to which questions can be directed. If you have an electronic mailing address, please make that available as well.
2. Attach any information you believe is related to the request. The more complete your request is, the less time is required to review it.
3. Once completed, send your request to:
Rae McQuade
NAESB, Executive Director
1301 Fannin, Suite 2350
Houston, TX 77002

Phone: 713-356-0060
Fax: 713-356-0067

by either mail, fax, or to NAESB's email address, naesb@naesb.org.

Once received, the request will be routed to the appropriate subcommittees for review.

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

R05007

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction

or

Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction

Date of Request: 04/08/05

1. Submitting Entity & Address:

Electric Reliability Council of Texas
7620 Metro Center Drive
Austin, Texas 78744

2. Contact Person, Phone #, Fax #, Electronic Mailing Address:

Name : Mark Walker
Title : Deputy General Counsel
Phone : 512-225-7076
Fax : 512-225-7079
E-mail : mwalker@ercot.com

3. Description of Proposed Standard or Enhancement:

Review the NAESB WEQ business practice standards that address coordinate interchange (WEQBPS-002-000), area control error (ACE) special cases (WEQBPS-003-000), manual time error correction (WEQBPS-004-000), inadvertent interchange payback (WEQBPS-005-000), and transmission loading relief (Eastern Interconnection) (WEQBPS-006-000) and remove any references to the Electric Reliability Council of Texas (ERCOT). The above-referenced NAESB WEQ standards are generally referred to as the 'Version 0' standards.

4. Use of Proposed Standard or Enhancement (include how the standard will be used, documentation on the description of the proposed standard, any existing documentation of the proposed standard, and required communication protocols):

In 2004, NAESB and the North American Electric Reliability Council (NERC) initiated a process to review the current NERC Operating Policies and develop two sets of 'Version 0' standards for the industry - NERC reliability standards and NAESB business practice standards. NAESB's 'Version 0' standards are a translation of the business practice aspects of the NERC Operating Policies. References to ERCOT that were contained in the NERC Operating Policies were maintained during the translation, and those references should be removed from the NAESB 'Version 0' standards. Removing references to ERCOT is appropriate because ERCOT has its own standards and procedures that are under the exclusive jurisdiction of Texas regulatory authorities and ERCOT governance structure. NAESB standards reports to the Federal Energy Regulatory Commission (FERC) should not include references to ERCOT standards because the FERC does not have regulatory jurisdiction over ERCOT.

5. Description of Any Tangible or Intangible Benefits to the Use of the Proposed Standard or Enhancement:

Removing references to ERCOT is consistent with the regulatory framework applied to ERCOT's operations.

6. Estimate of Incremental Specific Costs to Implement Proposed Standard or Enhancement:

No costs to the industry are associated with the proposed enhancement.

7. Description of Any Specific Legal or Other Considerations:

See description above in 4 & 5.

8. If This Proposed Standard or Enhancement Is Not Tested Yet, List Trading Partners Willing to Test Standard or Enhancement (Corporations and contacts):

Not applicable.

9. If This Proposed Standard or Enhancement Is In Use, Who are the Trading Partners :

Not applicable.

10. Attachments (such as : further detailed proposals, transaction data descriptions, information flows, implementation guides, business process descriptions, examples of ASC ANSI X12 mapped transactions):

No attachments are included.

R05018

North American Energy Standards Board

**Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction**

or

**Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction**

Instructions:

1. **Please fill out as much of the requested information as possible. It is mandatory to provide a contact name, phone number and fax number to which questions can be directed. If you have an electronic mailing address, please make that available as well.**

2. **Attach any information you believe is related to the request. The more complete your request is, the less time is required to review it.**

3. **Once completed, send your request to:**
Rae McQuade
NAESB, Executive Director
1301 Fannin, Suite 2350
Houston, TX 77002

Phone: 713-356-0060
Fax: 713-356-0067

by either mail, fax, or to NAESB's email address, naesb@naesb.org.

Once received, the request will be routed to the appropriate subcommittees for review.

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

North American Energy Standards Board

**Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction**

or

**Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or
Electronic Transaction**

Date of Request: the 1st of soon, 2005

1. Submitting Entity & Address:

Joint Interchange Scheduling Work Group
A NERC/NAESB Production

2. Contact Person, Phone #, Fax #, Electronic Mailing Address:

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3. Description of Proposed Standard or Enhancement:

Revise the e-Tag specification to allow Purchasing-Selling Entities (PSEs) associated with a transmission segment in the tag optional approval rights. This option would be identical to the existing mechanism associated with Generation Providing Entities (GPEs) where, through the registry, a PSE can elect to participate in the e-Tag approval processes. Just as for the GPEs and LSEs, the PSE associated with a transmission segment in the e-Tag would be limited to approval or denial actions only. In the event that the PSE does not act prior to the evaluation deadline, their status will always be set to PASSIVE APPROVED. The recommendation should attempt to mitigate any potential delays in the approval process.

4. Use of Proposed Standard or Enhancement (include how the standard will be used, documentation on the description of the proposed standard, any existing documentation of the proposed standard, and required communication protocols):

This enhancement to the existing e-Tag specification and registry will provide transmission contract rights holders the ability to review and approve/deny e-Tag citing their transmission rights. This will be of particular interest for PSEs participating in the secondary transmission market conducted off the OASIS to prevent unauthorized uses of their transmission rights. In addition, if the PSE actively approves the e-Tag, it will provide transmission providers an indicator from the rights holder on the use of their rights as submitted by a third party (tag author). The provision of approval rights to the transmission related PSEs does not impart the ability to issue adjustments once the E-Tag has gone implement.

5. Description of Any Tangible or Intangible Benefits to the Use of the Proposed Standard or Enhancement:

This enhancement provides the PSEs an active voice in the approval/denial of e-Tags using their transmission rights. This will help ensure their rights are not being misused. This will be of particular interest for PSEs participating in the secondary transmission market conducted off the OASIS to prevent unauthorized uses of their transmission rights. In addition, if the PSE actively approves the e-Tag, it will provide transmission providers an indicator from the rights holder on the use of their rights as submitted by a third party (tag author), thus eliminating duplicative faxes and/or phone calls from the customer to the provider.

6. Estimate of Incremental Specific Costs to Implement Proposed Standard or Enhancement:

Since this enhancement would be implemented in the same manner as the past enhancement that provided GPEs with optional approval rights, much of the existing structure and code can be used as templates for this proposed enhancement. This will minimize time for development and testing. Cost estimates will potentially be developed as the standard is developed further.

7. Description of Any Specific Legal or Other Considerations:

This enhancement helps bring all parties associated with the physical aspect of a transaction into a common approval process. This inclusion of PSEs with transmission rights will add credibility to the e-Tag ensuring the correct presentation of the transaction.

8. If This Proposed Standard or Enhancement Is Not Tested Yet, List Trading Partners Willing to Test Standard or Enhancement (Corporations and contacts):

Once the enhancement is ready for testing, any PSE with transmission rights will be able modify their registry information to indicate they are willing to participate in the approval process. PSEMKT has unofficially indicated their willingness to participate in the testing.

9. If This Proposed Standard or Enhancement Is In Use, Who are the Trading Partners :

n/a

10. Attachments (such as : further detailed proposals, transaction data descriptions, information flows, implementation guides, business process descriptions, examples of ASC ANSI X12 mapped transactions):

To be developed and the following:.

This proposed enhancement to the e-Tag specification concerns adding optional approval rights to PSEs listed as “owners” of transmission rights who are not the tag author. This would be passive approval, i.e., no action means approval. Rationale: Provides accountability for one party’s use of another party’s transmission service and could add transparency to the secondary transmission market.

The proposal is to allow Purchasing-Selling-Entities (PSE) to register with the NERC Registry as an approval entities on E-tags which cite them as the PSE associated with a transmission segment(s).

Initially, E-tag was developed as a means to provide transaction information to reliability analysis tools (e.g., IDC, etc.) to help maintain reliability. Since then, the role of the E-tag has expanded to a means to communicate end result of many bi-lateral deals between PSEs, and between PSE and Transmission Providers, which comprise a single transaction.

Since E-tag had its origins in the reliability world, its construct was to only to entities responsible for maintaining reliability registered as approval entities.

The Interchange Authority concept recognized that there are in fact two sets of approvals – commercial and reliability. Whether handled sequential or in parallel, these approvals verify that a request for a transaction to be physically implemented has been approved or validated from both the commercial basis and on a reliability basis. The approval process ensures the integrity of the transaction, commercially and reliability.

Today, only PSEs associated with the source and the sink of a transaction can register as an approval entity. This provision was made to ensure that E-tags citing particular generation and/or load were in fact valid transactions. The next logical step is to afford that capability to those PSEs who contracted for transmission rights cited in the E-tag.

By allowing the PSE holding transmission rights/contracts to approve/deny tag where their rights are cited on the tag will provide the Transmission Provider additional information regarding the

use of those rights – the transmission customer can use this mechanism to communicate to the transmission provider that they agree/disagree with the representation of the transaction.

Standard Authorization Request Form

Title of Proposed Standard: Coordination of Nuclear Power Plant Licensing Requirements with Bulk Electric System Planning, Analysis, and Operations	
Request Date: Draft 1	10/20/04
Revision Date: Draft 2	4/1/05
Revision Date: Draft 3	5/23/05 (FINAL)

SAR Requestor Information		SAR Type (Put an 'x' in front of one of these selections)	
Name	Nuclear Energy Institute Grid Reliability Task Force	<input checked="" type="checkbox"/>	New Standard
Contact	David Gladey/Vince Gilbert	<input type="checkbox"/>	Revision to existing Standard
Telephone	610-774-7774/202-739-8138	<input type="checkbox"/>	Withdrawal of existing Standard
Fax	610-774-7782		
E-mail	dlgladey@pplweb.com or jvg@nei.org	<input type="checkbox"/>	Urgent Action

Purpose/Industry Need

The purpose of the standard is to ensure that coordination between the NPP licensee and the entities responsible for the planning, assessment, operation, and analysis of the electric system is consistently achieved in practice and is documented. The standard would apply only to those entities that interface with or provide services to a nuclear power plant (NPP).

Title 10 of the Code of Federal Regulations, Part 50 (10CFR50), Appendix A – General Design Criterion (GDC) 17 requires a NPP’s offsite power system to “Provide sufficient capacity and capability to assure that:

- 1.) Specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and
- 2.) The core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.”

The offsite power system is the preferred (primary) power supply for a NPP’s electrical loads used to operate equipment for the safe shutdown of the plant during both normal and accident conditions. The Nuclear Regulatory Commission (NRC) Standard Review Plan (NUREG 0800) is used by the NRC to verify that:

- “Two separate paths from the transmission network to the standby power distribution system are provided;
- Adequate physical and electrical separation exists; and
- The system has the capacity, capability, and reliability to supply power to all safety loads and other required equipment.”

The NUREG has specific criteria for evaluating the “capacity, capability, and reliability” of the electric system:

“The results of grid stability analysis must show that loss of the largest single supply to the grid does not result in the complete loss of preferred power. The analysis should consider the loss, through a single event, of the largest capacity being supplied to the grid, removal of the largest load from the grid, or loss of the most critical transmission line. This could be the total output of the station, the largest station on the grid, or possibly several large stations if these use a common transmission tower, transformer, or breaker in a remote switchyard or substation.”

The Canadian Nuclear Safety Commission requires Canadian Nuclear Power Plant Operators to similarly demonstrate an appropriately reliable supply to the plant. Coordination between the NPP, the Transmission Owner, and the Transmission Operator is required to provide such evidence.

Coordination is necessary to ensure that the entities responsible for the planning, assessment, operation, and analysis of the electric system are aware of the specific licensing requirements of each NPP and that they incorporate these NPP requirements into the planning, assessment, operation, and analysis of the electric system. This coordination requires the NPP licensee to convey its requirements to the responsible electric system entities. The coordination also requires the entities responsible for the planning, assessment, operation, and analysis of the electric system to demonstrate to the NPP licensee that the specific requirements of the NPP are being addressed by the electric system.

This coordination of NPP licensing requirements with the electric system is not a new responsibility. Historically, in vertically integrated utilities owning a NPP facility, this coordination took place within a single organization. With the unbundling of ownership of the NPP facilities and separation from the entities owning and operating the electric system, that coordination is more challenging. Typically, the need for this coordination is addressed in interconnection, interface, or other agreements.

Reliability Functions

The proposed standard will apply to the following functions, <u>if they interface with or provide applicable services to Nuclear Power Plants.</u>		
<input checked="" type="checkbox"/>	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
<input checked="" type="checkbox"/>	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
<input type="checkbox"/>	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
<input checked="" type="checkbox"/>	Planning Authority	Plans the bulk electric system.
<input checked="" type="checkbox"/>	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
<input checked="" type="checkbox"/>	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements.
<input checked="" type="checkbox"/>	Transmission Owner	Owns transmission facilities.
<input checked="" type="checkbox"/>	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
<input checked="" type="checkbox"/>	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer.
<input checked="" type="checkbox"/>	Generator Owner	Owns and maintains generation unit(s).
<input checked="" type="checkbox"/>	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
<input type="checkbox"/>	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
<input checked="" type="checkbox"/>	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
<input checked="" type="checkbox"/>	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user.

Reliability and Market Interface Principles

Applicable Reliability Principles <i>(Check boxes for all that apply by double clicking the grey boxes.)</i>	
<input checked="" type="checkbox"/>	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
<input checked="" type="checkbox"/>	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
<input checked="" type="checkbox"/>	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
<input checked="" type="checkbox"/>	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
<input checked="" type="checkbox"/>	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
<input checked="" type="checkbox"/>	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
<input checked="" type="checkbox"/>	7. The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? <i>(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)</i>	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage. Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Scope

The proposed standard will include the requirements to coordinate and consider, in the planning, assessment, analysis, and operation of the electric system, each specific NPP's licensing requirements for:

1. Offsite power to enable safe shutdown of the plant during an electric system or plant event; and
2. Preventing unnecessary challenges to nuclear safety as a result of an electric system disturbance or transient as described in the NPP's licensing requirements.

The proposed standard would address the following elements:

- Coordination of electric system planning, assessments, and operations with NPP licensing requirements.
- Coordination of electric system constraints, including stability requirements, with NPP licensing requirements. Electric system analysis must, for example, verify that grid voltage will be adequate and grid stability will be satisfactory if the NPP trips off line. The analysis should address local switchyard conditions and reactive limitations of nearby generators that may influence voltage in the NPP switchyard.
- Coordination of electric system and NPP maintenance activities with respect to grid operations and NPP licensing requirements.
- Coordination of electric system reliability and contingency analysis, including identification of scenarios to be considered, with NPP licensing requirements.
- Consideration of NPP or electric system design changes that may impact the ability to supply acceptable offsite power to the NPP.
- Communication and coordination of actions to mitigate off-normal and emergency conditions in the electric system that may affect the NPP. For, example, this includes conditions when the NPP or other generators have their automatic voltage regulator or power system stabilizer not in automatic control mode, and ensuring the acceptability of the NPP offsite power under such conditions. This also includes informing the NPP licensee when grid conditions are degraded such that the voltage and stability requirements cannot be met.
- Communications protocols between NPP licensee and entities responsible for operation and planning of the electric system to address all items above.

The scope of the proposed standard will address only additional requirements unique to nuclear plants. The scope will not replace or duplicate existing standards related to generators. The standard drafting team will need to compare the proposed standards to existing requirements to avoid conflicts or duplications.

Related Standards

Standard No.	Explanation
Attachment A	Attachment A lists 73 requirements in the existing reliability standards related generically to generators. The proposed new standard would address only aspects that are unique to the licensing requirements of Nuclear Power Plants and would not duplicate the standards that already exist to define the relationship between electric

	system entities and generators.
TPL-001 to TPL-004	Tables in TPL-001 to TPL-004 address transmission performance requirements. Proposed new standard will be compared to these standards to ensure there is no conflict or duplication with the TPL standards.
TOP-004, TOP-006, TOP-008.	These standards refer to operating within IROL and actions and notifications when there is an IROL violation.
EOP-005-0	R9.4. The existing standard makes mention of priority during system restoration “The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.”

Related SARs

SAR ID	Explanation
Various	The Phase III-IV Planning Standards are currently in development. These standards include requirements for coordination of generator protection and validation of generator real and reactive power capability, voltage controls, etc. The proposed nuclear standard must avoid duplicating requirements emerging in those standards.

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Standard Number	Requirement Number	Existing Reliability Standard Requirements with "Generator" in the Text of the Requirement
BAL-005-0	R 1.1.	Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.
CIP-001-0	R 1.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi site sabotage affecting larger portions of the Interconnection.
CIP-001-0	R 2.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.
CIP-001-0	R 3.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.
CIP-001-0	R 4.	Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.
COM-002-0	R 1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.
EOP-001-0	R 7.3.	The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)
EOP-004-0	R 2.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.
EOP-004-0	R 3.	A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.
EOP-004-0	R 3.1.	The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.
EOP-004-0	R 3.3.	Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

Standard Number	Requirement Number	Existing Reliability Standard Requirements with "Generator" in the Text of the Requirement
EOP-004-0	R 3.4.	If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Reliability Organization approval.
EOP-004-0	R 4.	When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.
EOP-009-0	R 1.	The Generator Operator of each blackstart generating unit shall test the startup and operation of each system blackstart generating unit identified in the BCP as required in the Regional BCP (Reliability Standard EOP-007-0_R1). Testing records shall include the dates of the tests, the duration of the tests, and an indication of whether the tests met Regional BCP requirements.
EOP-009-0	R 2.	The Generator Owner or Generator Operator shall provide documentation of the test results of the startup and operation of each blackstart generating unit to the Regional Reliability Organizations and upon request to NERC.
FAC-002-0	R 1.	The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:
FAC-002-0	R 2.	The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional Reliability Organization(s) Regional Reliability Organization(s) and NERC on request (within 30 calendar days).
FAC-004-0	R 1.	The Transmission Owner and Generator Owner shall each document the methodology(ies) used to determine its electrical equipment and Facility Rating. Further, the methodology(ies) shall comply with applicable Regional Reliability Organization requirements. The documentation shall address and include
FAC-004-0	R 2.	The Transmission Owner and Generator Owner shall provide documentation of the methodology(ies) used to determine its transmission equipment and Facility Ratings to the Regional Reliability Organization(s) and NERC on request (30 calendar days).
FAC-005-0	R 1.	The transmission Owner, and Generator Owner shall each have on file or be able to readily provide, a document or database identifying the Normal and Emergency Ratings of all of its transmission facilities (e.g., lines, transformers, terminal equipment, and storage devices) that are part of the interconnected transmission systems. Seasonal variations in Ratings shall be included as appropriate.
FAC-005-0	R 2.	The Transmission Owner and Generator Owner shall provide the Normal and Emergency Facility Ratings of all its transmission facilities to the Regional Reliability Organization(s) and NERC on request (30 calendar days).
INT-004-0	R 2.	A Generator Operator or Load Serving Entity may request the Host Balancing Authority to modify an Interchange Transaction due to loss of generation or load.

Standard Number	Requirement Number	Existing Reliability Standard Requirements with "Generator" in the Text of the Requirement
IRO-001-0	R 3.	The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.
IRO-001-0	R 8.	Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.
IRO-004-0	R 4.	Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity in the Reliability Coordinator Area shall provide information required for system studies, such as critical facility status, Load, generation, operating reserve projections, and known Interchange Transactions. This information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.
IRO-005-0	R 9.	The Reliability Coordinator shall coordinate with other Reliability Coordinators and Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with other Reliability Coordinators and Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
IRO-005-0	R13.	Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.
IRO-005-0	R17.	When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.
MOD-010-0	R 1.	The Transmission Owners, Transmission Planners Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide appropriate equipment characteristics, system data, and existing and future Interchange Schedules in compliance with its respective Interconnection Regional steady-state modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-011-0_R 1.
MOD-010-0	R 2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-011-0_R1) shall provide this steady-state modeling and simulation data to the Regional Reliability Organizations, NERC, and those entities specified within Reliability Standard MOD-011-0_R 1. If no schedule exists, then these entities shall provide the data on request (30 calendar days).
MOD-011-0	R 1.	The Regional Reliability Organizations within an Interconnection, in conjunction with the Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive steady-state data requirements and reporting procedures needed to model and analyze the steady-state conditions for each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate the development of the data requirements and reporting procedures for that Interconnection. The Interconnection-wide requirements shall include the following steady-state data requirements:
MOD-012-0	R 1.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide appropriate equipment characteristics and system data in compliance with the respective Interconnection-wide Regional dynamics system modeling and simulation data requirements and reporting procedures as defined in Reliability Standard MOD-013-0_R 4.

Standard Number	Requirement Number	Existing Reliability Standard Requirements with "Generator" in the Text of the Requirement
MOD-012-0	R 2.	The Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners (specified in the data requirements and reporting procedures of MOD-013-0_R4) shall provide dynamics system modeling and simulation data to its Regional Reliability Organization(s), NERC, and those entities specified within the applicable reporting procedures identified in Reliability Standard MOD-013-0_R 1. If no schedule exists, then these entities shall provide data on request (30 calendar days).
MOD-013-0	R 1.	The Regional Reliability Organization, in coordination with its Transmission Owners, Transmission Planners, Generator Owners, and Resource Planners, shall develop comprehensive dynamics data requirements and reporting procedures needed to model and analyze the dynamic behavior or response of each of the NERC Interconnections: Eastern, Western, and ERCOT. Within an Interconnection, the Regional Reliability Organizations shall jointly coordinate on the development of the data requirements and reporting procedures for that Interconnection. Each set of Interconnection-wide dynamics data requirements shall include the following dynamics data requirements:
MOD-013-0	R 1.1.1.	Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained. In no case shall other than unit-specific data be reported for generator units installed after 1990.
PRC-001-1	R 1.	Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.
PRC-001-1	R 2.	Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
PRC-001-1	R 2.1.	If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
PRC-001-1	R 3.	A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
PRC-001-1	R 3.1.	Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
PRC-001-1	R 4.	Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
PRC-001-1	R 5.	A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:
PRC-001-1	R 5.1.	Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.

Standard Number	Requirement Number	Existing Reliability Standard Requirements with “Generator” in the Text of the Requirement
PRC-004-0	R 1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.
PRC-004-0	R 2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system shall provide to its affected Regional Reliability Organization and NERC on request (within 30 calendar days) documentation of the misoperations analyses and corrective actions according to the Regional Reliability Organization’s procedures of Reliability Standard PRC-003-0_R 1.
PRC-005-0	R 1.	The Transmission Owner, Generator Owner and Distribution Provider that owns a transmission protection system shall have a transmission protection system maintenance and testing program in place. The program(s) shall include:
PRC-005-0	R 2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission protection system shall provide documentation of its transmission protection system program and its implementation to the appropriate Regional Reliability Organization and NERC on request (within 30 calendar days).
PRC-012-0	R 1.	Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:
PRC-013-0	R 1.	The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with an SPS installed shall maintain an SPS database. The database shall include the following types of information:
PRC-015-0	R 1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list of and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R 1.
PRC-015-0	R 2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.
PRC-015-0	R 3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of Studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).
PRC-016-0	R 1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R 1.
PRC-016-0	R 2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall take corrective actions to avoid future misoperations.

Standard Number	Requirement Number	Existing Reliability Standard Requirements with "Generator" in the Text of the Requirement
PRC-016-0	R 3.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).
PRC-017-0	R 1.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
PRC-017-0	R 2.	The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).
TOP-001-0	R 3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.
TOP-001-0	R 6.	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.
TOP-001-0	R 7.	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:
TOP-001-0	R 7.1.	For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
TOP-001-0	R 7.3.	When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.
TOP-002-0	R 3.	Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.
TOP-002-0	R13.	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.
TOP-002-0	R18.	Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

Standard Number	Requirement Number	Existing Reliability Standard Requirements with "Generator" in the Text of the Requirement
TOP-003-0	R 1.1.	Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.
TOP-003-0	R 1.2.	Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.
TOP-003-0	R 2.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.
TOP-003-0	R 3.	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
TOP-006-0	R 1.1.	Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
TPL-006-0	R 1.4.	Supply-side resources and their characteristics (existing and planned generator units, Ratings, performance characteristics, fuel types and availability, and real and reactive capabilities.)
VAR-001-0	R 9.	Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of voltage regulators and power system stabilizers.
VAR-001-0	R 9.1.	When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.

**Amended and Restated Memorandum of Understanding for the
North American Energy Standards Board, North American Electric Reliability Council
and the ISO/RTO Council**

This Memorandum of Understanding (“MOU”) is entered into this 15th day of May, 2003, among the North American Energy Standards Board (“NAESB”), the North American Electric Reliability Council (“NERC”), and the Independent System Operator/Regional Transmission Organization Council (“ISO/RTO Council”) (collectively, “Parties”).

Whereas NAESB is the primary industry forum for development and promotion of business practice and electronic communication standards in North American wholesale and retail natural gas and electricity markets and its stakeholder-based standards development process is well-suited for the resolution of issues that affect or implicate business practices;

Whereas NERC is the primary industry organization for developing reliability standards for the reliable operation and planning of the bulk electric systems serving North America and NERC as an organization is well-suited for addressing reliability issues related to such standards;

Whereas the ISO/RTO Council is a duly formed organization composed of ISO and RTO chief executive officers, and its Charter has been filed with the Federal Energy Regulatory Commission (“FERC”) and other appropriate regulatory authorities in North America;

Whereas each of the Parties has duly authorized its representative to execute this MOU and bind the Organization to abide by the provisions set forth in this MOU;

Whereas the ISO/RTO Council is not a standards development organization, but may participate in standardization activities and existing standards development organizations, including preparing proposed standards for those organizations;

Whereas the Parties understand “policy” in the context of this MOU to mean a definite course of action selected from among alternatives that will guide and determine subsequent material decisions, and also understand “ISO and RTO policy” to mean major market and transmission tariff policies¹ that would normally be proposed and implemented by ISOs and RTOs and which require approval by the FERC or other appropriate regulatory authorities in North America;

¹ In Canada, the more common term for this is market rules.

Whereas NAESB is precluded by its Charter from setting industry policy, NERC is organized to set reliability policy, and individual RTOs and ISOs are organized to operate transmission systems and administer markets;

Whereas individual ISOs and RTOs must, in carrying out their responsibilities, develop ISO and RTO policy proposals and must also, subject to receiving all required and appropriate regulatory approvals, implement such policies;

Whereas the Parties agree that there is a need to develop and maintain standards to enhance electricity markets and maintain reliability throughout North America;

Whereas the Federal Energy Regulatory Commission (“FERC”) has “strongly urged” the Parties to coordinate standards development efforts;

Whereas most electric industry standards have both business and reliability implications and range along a continuum from “predominantly reliability” in nature to “predominantly business” in nature;

Whereas the Parties agree that a coordination process should be developed among the Parties to ensure that the development of business practice and reliability standards is coordinated and harmonized with the development, approval and implementation of ISO and RTO policy and that every practicable effort is made to eliminate overlap and duplication of efforts;

Whereas, the FERC Commissioners and Staff have encouraged the Parties to bring the functions previously addressed by the Electronic Scheduling Collaborative (“ESC”) and the Oasis Standards Collaborative (“OSC”) into the functionally appropriate Party organization, and through that organization into a single process for coordinating standard-setting;

Whereas, the Parties agree that all the current activities of the ESC and OSC should be included in one or several of the Parties’ organizations and thus brought into the single standard setting coordination process as defined in this Memorandum of Understanding;

Whereas, the Parties agree that the coordination that takes place under this MOU should not delay the development of standards or the implementation of ISO and RTO policy;

Whereas, the Parties shall not be obliged to change their existing standards approval processes, but the parties agree it would be beneficial to keep an open mind for future changes to be considered that would improve the processes and achieve the goals contained within this MOU; and,

Whereas, the Parties intend this MOU to be a living document and recognize that the coordination procedures detailed in this MOU are likely to require revision as the Parties gain experience working under these procedures,

Now therefore, the Parties agree as follows:

1. Purpose and Principles of Agreement

1.1 The Parties propose to establish a coordination process set forth in Section 2 of this MOU. The coordination process is intended to avoid overlap and duplication of effort in the activities of the three organizations by distinguishing the development, proposal and implementation of ISO and RTO policy from the setting of reliability standards or business practice standards. The coordination process will accomplish this primarily through the Joint Interface Committee (“JIC”) comprised of representative members of NERC, NAESB and the ISO/RTO Council. The JIC is not intended to delay standards development or the implementation of ISO and RTO policy, but to facilitate efficient policy implementation and standards development and to avoid duplication of effort between and among the Parties.

1.2 The Parties recognize that many standards have implications that affect aspects of reliability, market administration and transmission system operation, and business standards and communication protocols. Accordingly, the JIC will evaluate each standards development proposal, as well as the annual plans² of each organization, in a two-stage process as described in section 2.5 before determining whether NAESB or NERC should develop the proposed standard.^{3 4}

1.3 The Parties intend to have the coordination process set forth in Section 2 of the MOU in full operation by June 1, 2003. The Parties may mutually agree to move the start date for the coordination process.

² The JIC is not limited to new standards or annual plan items, but can receive existing proposed standards or annual plan items referred to it by any Party.

³ While the JIC will evaluate the disposition of standards with the recognition that most standards have both reliability and business standards and communication protocols implications, the intent of NERC and NAESB (through the JIC) is that the coordination process should work toward the development of “standards for the industry” and avoid characterizing standards, wherever possible.

2. Coordination Process

2.1 The Parties agree to establish a process, as set forth in this section, for coordinating the development of proposed standards, in accordance with the principles in Section 1 of this MOU.

2.2 The JIC shall be responsible for the coordination process. The JIC shall be composed of representatives from NERC holding one-third of the votes, representatives from NAESB WEQ holding one-third of the votes and representatives from the ISO/RTO Council holding one-third of the votes. Each Party will determine its representatives to the JIC, with every effort to have each segment or area represented. The quorum necessary for the transaction of business at meetings of the JIC shall require a majority of the representatives of each of any two Parties. Any or all members of the JIC may participate in a meeting, including being counted as part of the quorum, by means of a communication system by which all persons participating in the meeting are able to hear each other. Use of notational balloting or proxies will not be permitted. NERC, NAESB and the ISO/RTO Council will separately determine whether designated alternates will be permitted to participate in place of their absent JIC representatives. The JIC will have co-chairs, one representing NERC, one representing NAESB, and one representing the ISO/RTO Council chosen by each Party from among its JIC representatives.

2.3 Decisions of the JIC will be by a simple majority of all votes cast, with each NERC representative present at a meeting having a vote equal to 33.3% divided by the number of NERC representatives participating in the meeting, each NAESB representative having a vote equal to 33.3% divided by the number of NAESB representatives participating in the meeting, and each ISO/RTO Council representative having a vote equal to 33.3% divided by the number of ISO/RTO Council representatives participating in the meeting. In the event any Party fails to be represented by at least one representative and quorum requirements are met, the remaining two Parties shall each receive 50% of the vote, to be divided equally among the Party's representatives. In the event of a tie vote, the matter will be referred to the Chairmen of the Parties present for the tie vote [or their Board level designee(s)] for resolution. In the determinations made under Section 2.6, each Party may abstain from voting on any question in which it determines it does not have a material interest.

⁴ The Parties expressly agree that reliability and business practice standards that are required for ISO/RTO Council activities would typically be developed by NERC and NAESB, consistent with this MOU.

2.4 The JIC will meet as necessary to review the annual plans of each organization. Additionally, the JIC will meet as necessary to review each Standards Authorization Request (“SAR”) that the Standards Authorization Committee (“SAC”) of NERC has approved for the drafting of a standard, each standard request that the NAESB Executive Committee (“EC”) has assigned to the Wholesale Electric Quadrant (“WEQ”) of NAESB and each ISO and RTO policy anticipated to be proposed or implemented by the ISO/RTO Council’s constituent organizations that may affect business practice standards and reliability standards.

2.5 In the first stage of its process, the JIC will evaluate the annual plans of each Party. If the JIC determines that an annual plan item would establish or require substantial modification to ISO and RTO policy, then standard setting activities associated with the annual plan item would normally be deferred⁵ until the FERC or other appropriate regulatory authorities in North America have exercised their authority to determine such policy issues. Once such ISO and RTO policy issues have been resolved, further standards development activity will be coordinated by the JIC according to this MOU. If the JIC does not determine that an annual plan item would establish or require substantial modification to ISO and RTO policy, then the item would continue through the standards development process. If the JIC determines that an aspect of the ISO/RTO Council’s annual plans would alter or require new business practice standards, communication protocol standards or reliability standards, those standards development activities would be coordinated by the JIC according to this MOU. The JIC may also recommend that a particular item or aspect of an item in one Party’s annual plan be removed from that Party’s annual plan and added to another Party’s annual plan in order to carry out the purposes of this agreement.

2.6 Once the JIC has made the determinations in section 2.5, the second stage of the process will take place. In this stage the JIC will consider the relationship of each specific standards proposal, including any standards proposals derived from ISO and RTO annual plan items, to the reliability responsibilities of NERC and the business standards and electronic communication protocol responsibilities of NAESB, and will refer the development of the standard as appropriate to the two organizations. In this stage, the JIC may also determine

⁵ If the FERC or other appropriate regulatory authorities in North America have already assigned the item to the ISO/RTO Council’s constituent organizations for development of a policy proposal, the Parties may await the policy

whether a specific standards request proposal would itself primarily establish or substantially modify ISO and RTO policy, in which case standards development may be deferred until the FERC or other appropriate regulatory authorities have determined the resolution of such policy issues. Once the JIC has assigned or referred the standards proposal for further development, the members and constituents of the other organizations are strongly encouraged to actively engage in the development process by participating in subcommittee, task force and working group deliberations as well as offering comments and recommendations on any and all aspects of the proposed standard or policy.

2.7 The JIC will make such determinations by the end of the month subsequent to the month in which the annual plan item, standards request proposal or proposed ISO and RTO policy is referred to the JIC. The JIC may prioritize submitted proposals if there are urgent reliability, business, or policy implications.

2.8 All interested individuals and entities are invited and encouraged to participate to the maximum extent possible consistent with membership or registration requirements in NERC, NAESB and the ISO/RTO Council standards development and policy development activity. None of the organizations places any membership or registration requirement on the submission of comments on draft proposed standards or policy development.

2.9 With respect to the provisions of section 2.6, either the determination of the JIC or the resolution reached in the event of a tie vote will become final after thirty days unless, within that thirty-day period, one of the Parties acts to withdraw a standards request proposal. In this event, the proposal may be redrafted and resubmitted to the JIC or the Parties shall meet to attempt to resolve the impasse. Should further consideration not result in a final determination, each of the parties may act consistent with its own standards development or policy definition process. Likewise, with respect to the provisions of section 2.5, a determination of the JIC or the resolution reached in the event of a tie vote will become final after thirty days unless, within that thirty-day period, one of the Parties disagrees with the determination. In this event, the annual plan item may be redrafted and resubmitted to the JIC or the Parties shall meet to attempt to further resolve the issue. Should further consideration not result in a final determination, each of

resolution. In the interim while awaiting the policy resolution, the Parties may identify specific standards activity needed to support any proposed policy resolution.

the parties may act consistent with its own standards development or policy development and implementation process.

2.10 Because the Parties' annual planning processes are iterative and are implemented through or otherwise affect the standards setting processes, the JIC may discuss coordination of ongoing annual plan development and implementation, and each Party, through its JIC members, may make recommendations regarding other Parties' annual plan development and implementation.

3. Filings With Governmental and Regulatory Authorities

3.1 Each Party shall be responsible for making filings with governmental and regulatory authorities as appropriate.

3.2 The Parties agree that all meetings of the JIC will be duly noticed, open and transcribed, and that the JIC's deliberations and all supporting documents, including any minority opinions, will be a matter of public record and may be provided by any Party or any of its members in any filing with governmental authorities of a standard or other issue which the JIC has acted upon.

4. Information Exchange

4.1 Each Party will inform each other party each year of its projected standards development, significant policy development and implementation activities for the coming year and of any additional planned activity as it arises. After exchange of this information, the JIC will meet to address any apparent areas of duplicate or inconsistent effort as soon as practical.

4.2 With respect to each particular initiative regarding an RTO or ISO policy activity, or request for a standard or standard development action, each Party will promptly inform the other Parties of the action, or the request in sufficient detail to convey the subject matter and timeline for resolution of such action or request.

5. Costs

5.1 Each Party shall bear its own costs.

6. Reevaluation

6.1 The Parties agree to meet annually during the anniversary month of the signing of this MOU to evaluate in good faith the effectiveness and efficiency of this MOU in meeting the goal of coordinating the standards and policy development-related activities of the three organizations and to make any appropriate revisions.

6.2 The Parties may also agree to revise this MOU, including the appendices, at any other time as mutually agreeable.

7. Termination

7.1 Each Party may withdraw from this MOU upon 60 days' written notice to the other Parties. Notification of such withdrawal should be provided to the FERC or other appropriate Provincial or state regulatory authorities in North America. Prior to the withdrawal becoming effective, the Parties agree to meet to discuss whether changes to this MOU would address the reasons prompting the withdrawal.

8. Miscellaneous

8.1 Each Party is legally authorized to execute this MOU and to exercise the rights and perform the obligations and responsibilities contained in it.

8.2 This MOU constitutes the entire agreement between the Parties with respect to establishing a coordination process intended to avoid overlap and duplication of effort in the activities of the three organizations by distinguishing ISO and RTO policy-making from the setting of reliability and business practice standards supporting energy markets.

8.3 This MOU may be executed in counterparts each of which shall be deemed an original and all of which together shall constitute one instrument.

8.4 None of the Parties shall be liable for any indirect, special, incidental or consequential damages arising in any way from any performance or failure to perform under this MOU.

8.5 The Parties agree that they will create a process whereby the notice of JIC activities and documents are posted on a web site for public access.

8.6 This is an Amendment and Restatement of the Agreement dated November 30, 2002 between NERC and NAESB.

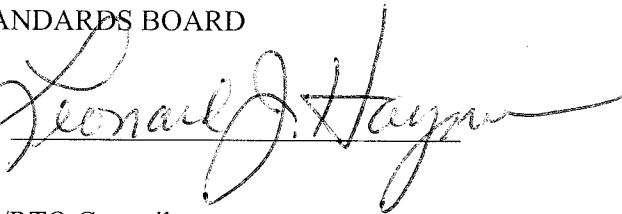
8.7 Nothing in this Agreement is intended for the benefit of third parties, and no third party may claim for damages or otherwise to enforce any such benefit.

8.8 Nothing in this Agreement shall be construed as establishing a joint venture, agency relationship, any authority of any signatory or the JIC to bind another signatory, or as intending to violate the antitrust laws.

AGREED TO as of this 15th day of May, 2003.

NORTH AMERICAN ENERGY
STANDARDS BOARD

By:



ISO/RTO Council

By:



NORTH AMERICAN ELECTRIC
RELIABILITY COUNCIL

By:



APPENDIX A

JIC Coordination Guidelines

The coordination guidelines for use by the JIC as a starting point, under section 2.6 of the MOU, are based in part upon NERC's Functional Model⁶ and in part upon market criteria developed by NAESB. As the JIC gains more experience alternative coordination guidelines may be developed and used as the JIC sees fit.

In general, the functions identified in the functional model diagrams as "generator" (whether merchant or load-affiliated), "purchasing-selling entity," "load-serving entity," "market operator," "customer aggregator," and certain of the relationships and information flows of "transmission service provider," "transmission owner," and "transmission operator" are associated with how wholesale electric business practices and electronic communication protocols are developed for use by market participants. Additionally, market criteria such as product or service definitions, specifications, and compensation; prerequisites for participation in market and identification of costs and funding obligations; arrangements for product and service delivery to customers; creditworthiness requirements; market-related business practices; market settlement practices; and communication protocols in support of market criteria should be considered. Standards development proposals applicable to those functions and to the relationships and information flows among those functions normally would be assigned to NAESB, regardless of where the original request for the standard was filed.

In general, the functions identified in the functional model diagrams as "reliability authority," "balancing authority," "interchange authority," "compliance monitor," "NERC," and certain of the relationships and information flows of "transmission service provider," "transmission owner," and "transmission operator" are associated with the reliable operation of the bulk power system. Standards development proposals applicable to those functions and to the relationships and information flows among those functions normally would be assigned to NERC, regardless of where the original request for the standard was filed.

⁶ A PowerPoint display of NERC's Functional Model may be downloaded at <http://www.nerc.com/~filez/fmrtg.html>. The Functional Model identifies and defines the functions, associated responsibilities, and the relationships and information flows among those functions, that are necessary for electric systems to operate reliably and for participants in wholesale electricity markets to transact business efficiently, independent of which entities perform which functions.

In general, the functions associated with ISO and RTO policy relate to proposals for and implementation of a definite course of action selected from among alternatives that will guide and determine subsequent material decisions for administering electricity markets and operating regional transmission systems, with the approval of the FERC or other appropriate regulatory authorities in North America. Such policy issues would normally be deferred until the FERC or other appropriate regulatory authorities in North America have exercised their authority to determine such policy issues.

Other factors that may be considered by the JIC in determining the assignment of a particular standards development request to NERC or NAESB include (but are not limited to):

- a. Regulatory direction to one organization or the other;
- b. The priority of the proposal and the ability of either organization to take on and complete the standard development in a timely manner, given its other workload; and
- c. Whether the proposal includes a significant reliability compliance element.