

NORTH AMERICAN ENERGY STANDARDS BOARD
Executive Committee Meeting - WEQ, REQ, RGQ, WGQ Meeting Materials
December 9-11, 2003

TAB 7
WEQ Draft Minutes



North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002
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TO: NAESB Wholesale Electric Quadrant Executive Committee, Posting for Interested Industry Participants

FROM: Todd Oncken, NAESB Deputy Director

RE: NAESB Wholesale Electric Quadrant Executive Committee Meeting Draft Minutes - October 7, 2003

DATE: October 8, 2003

**Wholesale Electric Quadrant Executive Committee
Tuesday, October 7, 2003
9:00 a.m. to 3:00 p.m. MST
Tempe, AZ**

1. Welcome

Mr. Cobb called the meeting to order and thanked Systrends for hosting. Mr. Oncken gave the antitrust advice. The roll of Executive Committee members was taken and quorum established.

2. Wholesale Electric Quadrant Draft Agenda & Draft Minutes

Mr. Cobb reviewed the agenda and no modifications were made. Mr. Goss moved, seconded by Mr. Jackson, to adopt the agenda as drafted. The motion passed absent objection.

Mr. Oberski moved, seconded by Mr. Berwager, to adopt the minutes of the August 5, 2003 and September 11, 2003 Wholesale Electric Quadrant (WEQ) Executive Committee meetings as drafted. The motion passed absent objection.

3. Review of New Requests and Assignments

The Triage Recommendations from October 1, 2003 were reviewed. It was noted that none of the recommendations for Requests R03019 - R03027 were assigned to the WEQ. Standards Requests R03020 and R03023 were discussed as they might have WEQ implications in the future. Ms. McQuade stated the WEQ might look at Request R03020, which proposes a definition for Applicable Regulatory Authority, when the term needs to be defined for WEQ standards. Likewise, she stated the WEQ might want to review Request R03023, which proposes a different technology (XML format) for presenting information, when it begins to draft information standards. Mr. Johnson noted there was debate in the Triage Subcommittee about whether Request R03023 should be assigned to the WEQ in addition to the assignment to the Wholesale Gas Quadrant (WGQ) and Retail Gas Quadrant (RGQ). The Triage Recommendations were submitted to all Executive Committee members for notational vote, with the recommendations for scope and quadrant being accepted by a majority of Executive Committee members.

4. Discussion and Approval of draft 2004 Annual Plan

Participants discussed the draft 2004 Annual Plan. Each annual plan item was reviewed and discussed.

Item 1: Develop business practice standards as needed to complement reliability standards. It was noted item 1 addresses the current initiatives of the Standards Review Subcommittee (SRS) to produce complementary business standards for NERC reliability standards. Participants briefly discussed the NERC Transition team, as noted on the annual plan strawman. It was explained that NERC has created and staffed a transition team to evaluate the current NERC Policies and determine which aspects of the NERC Policies are reliability standards and which are business standards. Ms. McQuade stated she, Mr. Desselle and Mr. Yeung have been named to the



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Transition team, and it is expected the team will begin its work in November 2003. It was noted that this exercise could produce potential business standards where NAESB would have to work on an expedited manner, much like a NERC Urgent Action SAR, but those procedures are currently in place through the prioritization of subcommittee work items.

Participants discussed whether item 1 was sufficient to address any impending standards which will be proposed by NERC due to the August 14 blackout. There was general consensus that item 1 was sufficient for that purpose. Mr. Fidrych, chair of the NERC Operating Committee, stated that he would anticipate a joint meeting between NERC and NAESB (probably through the SRS) after the preliminary report on the blackout is published to determine which standards development should be done by the organizations in lockstep.

Item 2: Develop and Maintain Business Practice and Communication Standards for OASIS and Electronic Scheduling. Mr. Cobb stated the Executive Committee established the Information Technology (IT) Subcommittee and Electronic Scheduling Subcommittee at the August Executive Committee meeting held in Philadelphia. It was noted that the first IT meeting is scheduled for October 8 and the ESS is currently dormant. Concern was expressed that item 2 was not sufficiently specific to give proper guidance to a subcommittee. Mr. Dison suggested item 2 be modified so that the current OASIS standards (FERC Order 638 and Standards & Communications Protocol) be adopted as NAESB standards and then make modifications to the standards as requested by the OSC Deliverables letter regarding OASIS 1A enhancements. Mr. Johnson concurred. Ms. McQuade stated that the NAESB Office has already begun preparing the referenced documents for adoption through the NAESB process.

Mr. Johnson proposed alternate language for item 2 which would separate the tasks by business practices and communication protocols, and then further according to timeline. Mr. Dayney questioned the necessity of continuing to work on OASIS 1A given the limited resources of the industry. Mr. Rodriguez noted that most organizations will continue to work under OASIS 1A for the near term since there has been discussion that OASIS 2 would be implemented on a regional basis. Mr. Johnson also stated there are some outstanding elements of FERC Order 638 that need to be addressed. It was not determined whether work on OASIS 1A and OASIS 2 would be done concurrently. Mr. Dison noted there is a pending standard request to complete the outstanding OASIS 1A work. It was suggested that a specific timing directive from the FERC would foster the development of OASIS 2. Mr. Harshbarger stated that originally the policy was OASIS 2 that would function under the concept of a single market design, but in 2002 the ESC decided to develop use cases to recognize the multiple markets in existence.

Mr. Dison moved, seconded by Ms. Robertson, to adopt the alternate language for item 2, as shown in the attachment to these minutes. Participants discussed the motion. The FERC ANOPR language was clarified and references to SMD were replaced with 'subsequent orders.' Additionally, (a)(ii)(c), *Develop and maintain business practices to support & implement the ESC use cases*, was added. Mr. Dison and Ms. Robertson accepted the modifications. It was noted that subcommittee assignments have not been made. The motion passed absent objection.

Item 3: Develop business practices standards to Improve the Current Operation of the Wholesale Electric Market. Mr. Cobb reviewed item 3 and stated that the Seams Subcommittee is currently developing a catalog of seams issues. It was noted the catalog results would be presented to the Executive Committee for further action and any standards development based on the catalog would stem from a decision of the Executive Committee to move forward.

Item 4: Investigate the need for electric or gas standards required to provide additional flexibility in generation scheduling (including gas nominations) through a specifically assigned task force. Mr. Jackson presented item 4. He stated he proposed item 4 as an opportunity for the WEQ to work



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proactively with the WGQ. Mr. Johnson noted there have been concerns stated as to whether the WEQ was the proper forum for this item instead of the WGQ. Mr. Oberski expressed concern about the specificity and measurability of the item as drafted. Mr. Jackson stated the end result of item 4 would likely be the presentation of a list of issues identified based on a joint review of wholesale gas and wholesale electric issues, not a specific standard. It was noted that the WEQ could request a change to WGQ standards, but could not direct or propose such a modification.

Mr. Jackson proposed alternate language for item 4, as follows: Determine the need for and develop, if necessary, standard(s) requests for electric or gas standards required to provide additional flexibility in generation scheduling (including gas nominations) through a specially designed task force. During discussion it was decided to remove the task force language. Mr. Yeung moved, seconded by Mr. Oberski, to approve the revised alternate language for item 4. The motion passed without objection.

Provisional Items. Each of the provisional items was presented and discussed. Mr. Small opposed the inclusion of the electric purchase and sales contract, stating that he thought the scope of the comment was misleading. Mr. Small has submitted written comments in opposition to the item previously. Mr. Dison stated that the interest referred to in the comment was evidenced through the submission of a standards request which was withdrawn due to resource concerns.

Participants discussed the adoption of the draft 2004 Annual Plan. It was noted that the comments present on the draft would be removed and replaced by completion dates and quadrant assignments. Mr. Johnson expressed concern that the information contained in the comments of the strawman would be maintained for future reference. It was noted that the strawman would be posted in connection with this meeting. Mr. Johnson preferred that it be captured as an appendix to the 2004 Annual Plan. Mr. Berwager opposed including the comments as they reference the contracts item as an appendix to the annual plan. Participants extensively discussed this issue.

Mr. Oberski moved, seconded by Mr. Dison, to approve the draft 2004 Annual Plan as amended today and with the inclusion of the comments as an appendix to that plan. Mr. Berwager moved, seconded by Ms. Westerfield, to add the following comment on the contracts provisional item: There is industry interest in developing a contract but there is neither consensus support nor resources to move forward in the 2004 Annual Plan. The amendment passed without opposition. Mr. Oberski's motion, as amended, passed without opposition.

5. Discussion of Subcommittee Organization

Participants discussed the WEQ subcommittee structure. Mr. Oberski proposed the formation of a Business Practices Subcommittee that would be a large subcommittee with technical expertise responsible for drafting the business practice standards through various task forces. It was proposed that the SRS and Seams Subcommittee would remain separate from the Business Practices Subcommittee and would work to scope issues and develop standards requests to be worked on by the Business Practices Subcommittee. It was also proposed that the Information Technology Subcommittee and Electronic Scheduling Subcommittee remain independent of the Business Practices Subcommittee as they are primarily technical groups. Current tasks forces would be reassigned within the new structure as appropriate. Under the proposed subcommittee scheme, the Contracts Subcommittee, Market Operations Subcommittee and Market Standards Subcommittee would become inactive.

After a brief discussion of the glossary efforts in the other quadrants, Mr. Dison proposed the addition of a Glossary Subcommittee. Discussion revealed that the task of the Glossary Subcommittee would be involved since there are current definitions from the other NAESB quadrants, definitions from the ISOs and IRC, and definitions from NERC that should be considered. Ms. Kiselewich stated that the WEQ Glossary Subcommittee could work with the other



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Glossary Subcommittees, as appropriate, in an effort to produce definitions for each quadrant that would be consistent with the other NAESB quadrants. Ms. McQuade stated that the proposed structure was similar to the structure used by the WGQ, with the exception of the SRS and Seams Subcommittee since the WGQ does not have similar coordination requirements with external agencies.

Mr. Yeung highlighted the primary issue for the for the proposed committee structure – subcommittee participation. Participants discussed the scope of the new subcommittees. It was suggested that although it was the purview of the Executive Committee to provide high-level guidance to the subcommittees, the development of subcommittee mission statements for presentation to and approval by the Executive Committee was the responsibility of each subcommittee. Nevertheless, Mr. Johnson expressed concern that the roles and scopes of each subcommittee be clearly defined.

Mr. Cobb and Mr. Harshbarger developed a graphical depiction of the new subcommittee structure. Both proposals were presented to the Executive Committee. Both diagrams were posted on the NAESB web site as work papers for this meeting.

Mr. Dison moved, seconded by Mr. Oberski, to revise the WEQ Executive Committee subcommittee structure by making the Market Operations Subcommittee, Contracts Subcommittee, and Market Standards Subcommittee inactive and establishing a Business Practices Subcommittee and Glossary Subcommittee. The effect of the motion is that the WEQ EC will now be composed of the following subcommittees: Business Practices, Information Technology, Standards Review, Seams, Electronic Scheduling, and Glossary. As a friendly amendment, references to the Market Operations Subcommittee, Contracts Subcommittee, and Market Standards Subcommittee were removed from the motion. The motion passed unanimously.

Participants agreed it would be appropriate to communicate the new subcommittee structure to the industry. Accordingly, it was agreed that the NAESB Office would draft a notice to that effect along with an invitation to participate in the new subcommittees. The notice will contain information on the new structure, including the tasks each subcommittee will perform. It was noted that assignment of the draft 2004 Annual Plan items to the new subcommittee structure was outstanding. Mr. Yeung suggested the initial assignment of annual plan items would provide a starting point for the new subcommittees to draft their mission statements. The leadership of the new subcommittees was identified as follows: Glossary – Mr. Reed; Business Practices – Mr. Oberski; ESS – Mr. Dison and Mr. Rodriguez. Ms. McQuade noted Mr. Simonelli, chair of the ESC, is a potential co-chair for the ESS. It was agreed that the NAESB Office would draft high level mission statements for each of the subcommittees, which would then be reviewed by the subcommittee leadership and Executive Committee members and used for the above-noted industry communication.

6. Subcommittee Updates and 2003 Annual Plan

Contracts Subcommittee: Mr. Dison reported there was a standards request for the development of an electric purchase and sales contract which was subsequently withdrawn. He noted it was discussed at length during the September 11, 2003 Executive Committee meeting in light of the history of the issue within NAESB.

Market Operations Subcommittee – Inadvertent Interchange Payback Task Force: Mr. Oberski reported on the efforts of the Inadvertent Interchange Payback Task Force (IIPTF). He stated the minutes from the August and September meetings were approved at the October 6 meeting and noted those minutes are a good recollection of those meetings. During the October 6 meeting, Mr. Oberski stated the IIPTF considered and took action on several motions. He stated the motions that



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were successful would form the basis of the task force's work moving forward. The next IIPTF meeting will be held on November 3, 2003 in Houston, TX.

Standards Review Subcommittee: Mr. Yeung reported on the work of the Standards Review Subcommittee (SRS), noting that the SRS has developed three standards requests that have proceeded through the JIC process and is evaluating two additional NERC Standards - Balance Resources and Demand and Facility Ratings - for needed complementary business standards. Mr. Yeung stated the following task forces have been established: Coordinate Interchange Business Practices (CIBP), Coordinate Operations Business Practice (COBP), and Operate Within Limits Business Practices (OWL-BP). Mr. Yeung stated a joint meeting has been scheduled between the CIBP and its NERC counterparties to further evaluate the need for complementary business standards. Mr. Yeung stated the COBP has completed a scoping document for the NERC Coordinate Operations SAR and determined no complementary business practices are needed at this time. He noted that decision was based partly on a lack of the implications of the NERC Standard and that the task force realized that this NERC Standard was not based on a corresponding NERC Policy. For the OWL-BP task force, Mr. Yeung stated that Mr. Rana will lead the task force which will potentially draft business standards that would assist an operator in achieving system management. As an example, Mr. Yeung said a business standard could relate to the transmission relief required by Order No. 888, but noted the task force is cautious to develop a standard that is a market business approach instead of a restatement of NERC Policy 9. The OWL-BP is in the scoping phase. Mr. Yeung stated an SRS conference call will be held on October 21 to continue its work on the initial review documents for the Balance Resources and Demand and Facility Ratings NERC standards.

Seams Subcommittee: Mr. Cobb reported on the progress of the Seams Subcommittee. He noted subcommittee leadership has made some preliminary decisions on moving forward with the subcommittee's work, including a timeline for the presentation and evaluation of the draft Seams Matrix. Mr. Cobb stated the Seams Matrix has 42 entries and additional entries are expected before the October 10 deadline. The Seams Subcommittee has scheduled its next meeting for November 4, 2003. Mr. Cobb stated the completed, categorized, and prioritized matrix will be presented to the Executive Committee at its December meeting.

Information Technology Subcommittee: Mr. Johnson provided the update on the Information Technology (IT) Subcommittee, noting its first meeting is scheduled for October 8, 2003 in Tempe, AZ. Mr. Johnson reviewed the agenda items for the IT meeting. He encouraged the Executive Committee to provide additional guidance on the scope of the IT's duties. For reference, Mr. Johnson provided a number of documents describing the history of OASIS.

7. Liaison Efforts

Electronic Scheduling Collaborative: Ms. McQuade reported on the liaison efforts with the Electronic Scheduling Collaborative (ESC). She stated the ESC has sent recent communications indicating that they are concluding their efforts on the use cases and should make them available shortly. Ms. McQuade noted that NAESB contacted the ESC in August to explain the transition from the OSC into the IT Subcommittee and to offer the ESC a similar transition plan through the formation of the Electronic Scheduling Subcommittee (ESS). Mr. Landrum suggested a scope document for the ESS be published and made available to current ESC members with a letter encouraging their participation in the ESS. Mr. Landrum stated an issue he has heard regarding participation in the ESS is NAESB membership. It was clarified that NAESB membership is not required for participation in NAESB subcommittees.

North American Electric Reliability Council (NERC): Ms. McQuade reported that she and Mr. Desselle met with NERC leadership during the month of September to discuss coordination between



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the organizations. The communication and coordination between NAESB and NERC for standards development is endorsed by leadership and is working well with the existing subcommittees and drafting teams. Further, she said NERC leadership strongly supports formalizing coordination through NAESB Executive Committee and SRS and NERC Markets Committee. It was noted this meeting addressed high-level coordination issues rather than specific points of coordination.

ISO-RTO Council (IRC): Ms. McQuade stated that she and Mr. Desselle attended the IRC meeting last month to present the draft 2004 Annual Plan and a report on the coordination efforts between NERC and NAESB. She stated Mr. Tammar has been identified as the point of contact for NAESB's work with the IRC. She noted the IRC committed to participating in the Seams Matrix effort.

Joint Interface Committee: Mr. Yeung gave the report of the September 18 JIC meeting. He stated all standards requests presented by NAESB were assigned to NAESB for further development, and all standards requests presented by NERC were assigned to NERC for further development.

8. New Business

No new business was discussed.

9. Adjourn

Mr. Cobb adjourned the meeting at 2:53 p.m. Mountain Standard Time.



10. Executive Committee Attendance and Voting Record¹

End User Segment	Title, Organization	Attendance
John Hughes	Director Technical Affairs, Electricity Consumers Resource Council (ELCON)	Phone
V A C A N C Y	To be filled by the Large Industrials sub-segment	
Steve Sayuk	Manager Americas Supply, Power & Gas Services Group, ExxonMobil Power & Gas Services, Inc.	In Person
Randy Corbin	Assistant Director Analytical Services, Ohio Consumers' Counsel	Absent
Paul Jett	Manager of Electric System Operation Customer Choice Transition, Cinergy Services Inc.	Absent
LouAnn Westerfield	Policy Strategist, Idaho Public Utilities Commission, rep. National Association of Regulatory Utility Commissioners	Phone
Distribution/LSE Segment		
Thomas Ringenbach	Manager Business Standards, American Electric Power Service Corporation	Phone
Jack Leonard	Director, Transmission Management, Exelon PECO Energy	Phone
Patrick W. Frazier	Vice President of Energy Operations, American Municipal Power Ohio Inc.	Absent
Daniel E. Cooper	Engineering Manager, Michigan Public Power Agency	Absent
Syd Berwager	Industry Restructuring Project Manager, Bonneville Power Administration/Power Business Line	In Person
V A C A N C Y	To be filled by the Competitive Retailer sub-segment	
Generation Segment		
Bob Goss	Deputy Assistant Administrator of Power Resources, Southeastern Power Administration	In Person
Louis Oberski	Transmission Manager, Dominion Energy Marketing Inc.	In Person
Tony Reed	Project Manager, Southern Company Generation and Energy Marketing	In Person
Barb Robertson, alt. for B. Green	Ontario Power Generation	In Person
Steven B. Corneli	Director of Regulatory Affairs, NRG Power Marketing Inc.	Absent
William J. Gallagher	General Manager of Vermont Public Power Supply Authority	Absent
Marketers/Brokers Segment		
Gary L. Jackson	Senior Manager External Markets and Policy, Tennessee Valley Authority Bulk Power Trading	In Person
Joel Dison	Project Manager, Southern Company Generation and Energy Marketing	In Person
Greg Locke, alt. for C. Norris	Manager Strategic Analysis, North Carolina Municipal Power Agency #1	Phone
Charles Yeung	Director of Business Standards, Reliant Resources	In Person
Alan Johnson	Senior Policy Analyst, Mirant	In Person
Michael F. Gildea	Director of Regulatory Policy, Duke Energy North America	Phone

¹ All motions during the meeting passed by consensus of all Executive Committee members in attendance.



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Transmission Segment

Steven C. Cobb	Manager Grid Access and Scheduling Services, Salt River Project	In Person
Darrell Gerrard	Vice President Transmission Systems, PacifiCorp	Absent
John Lucas	Manager, Transmission Services, Southern Company	Phone
Mary Ellen Paravalos	Manager ITC Development, National Grid USA	Phone
Dan Klempel	Director Transmission Regulatory Compliance, Basin Electric Power Cooperative	Absent
Julie Voeck	Manager Strategic Policy and Planning, American Transmission Company	Phone

11. Other Participation

Administrative:

Rae McQuade	-Executive Director
Veronica Thomason	-NAESB Staff
Todd Oncken	-Deputy Director
Meghan McMillan	-NAESB Staff

Observers to the Meeting:

Name	Company	In person/Phone
Brenda Anderson	Bonneville Power Admin.	Phone
Robert Blohm	Economist	In Person
Scott Brown	Exelon Corporation	In Person
Kevin Burns	OATI	In Person
John Conlon	Midwest ISO	In Person
Phil Cox	AEP	In Person
Jack Crowley	Exelon Corporation	In Person
Ed Davis	Entergy	Phone
Duane Farmer	Public Service Company of New Mexico	In Person
Mark Fidrych	WAPA	In Person
Ken Gates	Conectiv	Phone
Peter Harris	ISO New England	In Person
Jim Hartwell	NPCC	In Person
William Heinrich	New York Public Service	Phone
Ruth Kiselewich	Baltimore Gas & Electric	In Person
Todd Kochheiser	Bonneville Power Admin.	In Person
Barry Lawson	NRECA	Phone
Steve McCoy	CAISO	In Person
Shirley McKean	Salt River Project	In Person
Denyse Marcil	Hydro-Quebec Transenergie	In Person
Marjorie Pearlman	Energy East Management Corp.	Phone
Sharon Miller	Excel Energy	Phone
Talal Murib	Southern Company	In Person
Barbara Rehman	Bonneville Power Admin.	In Person
Lisa Robert	Defense Energy Support	Phone
Andrew Rodriguez	PJM	In Person
Peter Rogan	ISO New England	In Person
Marv Rosenberg	FERC	In Person



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William Smith
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Steve Terelmes
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NORTH AMERICAN ENERGY STANDARDS BOARD
Executive Committee Meeting - WEQ, REQ, RGQ, WGQ Meeting Materials
December 9-11, 2003

TAB 8

WEQ 2003 Annual Plan and Subcommittee Updates



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NORTH AMERICAN ENERGY STANDARDS BOARD

2003 WEQ Annual Plan Modified by the Executive Committee - August 5, 2003

	Item Description	Completion ¹	Assignment
1	Develop business practices standards as needed to complement reliability standards.		
	a) Apply NERC/NAESB MOU provisions in reviewing proposed reliability standards for their business practice implications.	2 nd Qtr 2003	Standards Review Subcommittee (SRS)
	Status: Underway		
	b) Review existing NERC reliability policies and standards for their business practice implications.	2 nd Qtr 2003 Low priority	SRS
	c) Review each of the SARs in light of the NERC/NAESB MOU.	Ongoing High priority	SRS
	Status: Underway		
2	Develop business practices standards for OASIS and Electronic Scheduling		
	a) Develop business practice standards as needed for OASIS and electronic scheduling including determining which, if any, ESC/OSC and other related industry groups' business practices and standards should be developed into NAESB standards.	4 th Qtr 2003 Medium/High priority ²	Market Standard Subcommittee (MSS)
	Status: Underway - subcommittees for ESC and OSC created.		
	b) Develop standard communication protocols and cybersecurity requirements as needed for OASIS and electronic scheduling including determining which, if any, ESC/OSC and other related industry standard communication protocols and cybersecurity requirements should be developed into NAESB standards.	4 th Qtr 2003 Ongoing High priority	Technical Subcommittee
	Status: Underway - subcommittees for ESC and OSC created.		
3	Develop business practices standards in Support of a Standard Market		
	a) Develop standards and model business practices in accordance with FERC orders and rules issued in the SMD docket (RM01-12-000), or pursuant to Order Nos. 888 or 2000, or otherwise directed by the FERC.	Per FERC Order High priority	MSS
	b) Respond to FERC inquiries pertaining to business practice standard development and keep FERC informed on the nature and effectiveness of coordination activities with other standards setting organizations.	Ongoing High priority	MSS

¹ Dates in the completion column are by end of the quarter for completion by the assigned committee. The dates do not necessarily mean that the standards are fully staffed so as to be implementable by the industry, and/or ratified by membership. If one item is completed earlier than planned, another item can begin earlier and possibly complete earlier than planned. There are no begin dates on the plan.

² The EC determined that this item should carry a medium priority in terms of substance and a high priority in terms of organizational relations.



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2003 WEQ Annual Plan Modified by the Executive Committee - August 5, 2003

Item Description	Completion ¹	Assignment
4 Develop business practices standards to Improve the Current Operation of the Wholesale Electric Market		
a) Establish a standardized electric trading day. Status: Suspended pending EC guidance.	See Note 1.	Market Operations Subcommittee (MOS)
b) Identify and develop business practices on the public dissemination of market information.	See Note 1.	MOS
c) Establish standard business practices relating to:		
i) Definition and treatment of firm/nonfirm power;	See Note 1.	MOS
ii) Definition and treatment of firm/nonfirm transmission;	See Note 1.	MOS
iii) Provision of reserves for transactions across multiple control areas.	See Note 1.	MOS
d) Develop business standards as necessary to resolve seams issues between ISOs and RTOs. Status: Underway, catalog being developed.	See Note 1.	Seams Subcommittee
e) Develop standards for data requirements, data exchange and scheduling of day-ahead and real-time bilateral markets.	See Note 1.	MOS
f) Examine business practices and definitions currently in use to determine applicability on a North American basis. Status: Underway	See Note 1.	MOS
g) Catalogue, assess and prioritize existing "standards" that have significant business practice implications. Status: Underway	See Note 1.	MOS
h) Review activities of NERC CIPAG in light of NERC-NAESB MOU regarding cyber security requirements for their business practice and system communication standards implications. Status: Initial task force members identified, including NERC representation.	See Note 1.	MOS
5 Develop standardized contracts		
a) A review of both the Western Systems Power Pool and the Edison Electric Institute (EEI) Master Service agreements and other related agreements would be in order with the objective of developing standard short term and long term master-service agreements. Status: Complete - no action to be taken.	2 nd Qtr 2003 High priority for outreach	Contracts Subcommittee



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2003 WEQ Annual Plan Modified by the Executive Committee - August 5, 2003

	Item Description	Completion ¹	Assignment
	<p>b) A review of the EEI Master netting agreement with the objective of developing standard terms and conditions for netting settlements (perhaps this is a subset discussion of the master service agreements above). Status: Complete - no action to be taken.</p>	<p>2nd Qtr 2003 High priority for outreach</p>	Contracts Subcommittee
	<p>c) A review of the terms and conditions of the standard liquidated damages contracts ("into Entergy, Into Cinergy, etc.) with the objective of developing standard LD contract terms. Status. Complete - no action to be taken.</p>	<p>4th Qtr 2003 High priority for outreach</p>	Contracts Subcommittee
	<p>d) A review of the International Swaps and Derivatives Association (ISDA) cross commodity netting agreement Status: Complete. It was determined that this item was addressed by EEI and no further action was needed.</p>	<p>2nd Qtr 2003 High priority for outreach</p>	Contracts Subcommittee
	<p>e) Identify and develop business practices that would facilitate transactions between 2 parties when creditworthiness is an issue. Status: Working group to be established related to Seams catalog.</p>	<p>3rd Qtr 2003 High priority for outreach</p>	Contracts Subcommittee
	<p>f) Develop the Funds Transfer Agency Agreement. Status: Complete.</p>	<p>2nd Qtr 2003 High priority for outreach</p>	Contracts Subcommittee
6	<p>Develop business practices standards for Inadvertent Interchange Payback Practice. Status: Underway</p>	<p>2nd Qtr 2003 High/Medium priority</p>	MOS
7	<p>Develop business practices standards related to FERC's forthcoming generation interconnection orders (large and small generators), in Docket Nos. RM02-01-000 and RM02-12-000. Status: MSS to review current Large Generation Interconnection order to determine if any NAESB standards development activities are warranted.</p>	<p>4th Qtr 2003³ High priority</p>	MSS

Notes:

1. The WEQ EC Subcommittee will prioritize these items as appropriate and update the Board.

³ The completion date is dependent upon the issuance date of the generation interconnection orders.

DRAFT

Initial Standard Review and Analysis Report For NERC Standard 600 Determine Facility Ratings, System Operating Limits, and Transfer Capabilities

**NAESB WEQ Executive Committee
Standards Review Subcommittee
October 21, 2003**

Introduction

This document provides an initial review of the proposed NERC Standard 600 entitled “Determine Facility Ratings, System Operating Limits and Transfer Capabilities” in an effort to determine whether there is a need for companion business practice standards. This initial review does not constitute, but may result in, a proposed recommendation by the Standards Review Subcommittee to develop or propose a NAESB Standard.

Purpose and Status of NERC Standard 600

The stated purpose of Standard 600 is to determine facility ratings, system operating limits, and transfer capabilities necessary to plan and operate the bulk electric system within predefined facility and operating limits such that cascading outages, uncontrolled system separation, and voltage and transient instability are avoided. The standard is intended to apply to entities defined in the NERC functional model, but until such entities are certified, the standards will apply to existing entities effective upon adoption by the NERC Board of Trustees.

This document reviews Draft Standard Version 1 posted for comment from July 1, 2003 to August 29, 2003. Prior to the posting of the draft standard, four versions of a draft Standards Authorization Request were posted, with comment periods ranging from April 2, 2002 to January 31, 2003.

Actions Required Within the Standard

The standard is subdivided into six requirements and associated measures, two for each of the three components identified in the title to the standard. The first requirement is the development and availability of a methodology, and the second is the application of the defined methodology to determine and communicate the necessary values to those entities performing the reliability authority, planning authority, and transmission operator functions (i.e., the users). This results in the following standard requirements:

Facility Ratings	601	Transmission and generator owners document the methodology used to rate their facilities, identifying any assumptions and referencing industry rating practices or other standards.
	602	Transmission and generator owners establish their facility ratings based on the defined methodology, and communicate these to the user on a schedule established by that user.

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Transfer Capabilities

System Operating Limits	603	The reliability authority, planning authority, and transmission operators document the methodology to determine the operating limits that do not violate applicable facility ratings, and that avoid system performance outside pre-defined normal and contingency conditions. The methodology must address applicable contingencies, accuracy and level of detail of system models, SPSs or remedial action plans, transmission system configuration, generation dispatch and load level, and any reliability margins. (Of note is the inclusion of regional differences for NPCC consisting of pre-defined conditions for loss of multiple elements.)
	604	The responsible entities establish their system operating limits based on the defined methodology, and communicate these to the transmission service providers and transmission operators on a schedule established by those users.
Transfer Capabilities	605	The reliability and planning authorities document the methodology used to determine transfer capabilities that adhere to system operating limits with reference to transmission system topology, system demand, generation dispatch, current and projected transmission uses, and applicable reliability margins.
	606	The responsible entities establish their transfer capabilities based on the defined methodology, and communicate them, as requested, to NERC and its Regions, reliability authorities, transmission service providers, planning authorities, and transmission operators on a schedule established by each.

Items for Consideration for a Companion Business Practice Standard

NERC’s standard focuses on requirements that entities establish facility ratings and

- does not specify how or what methodology entities will employ to rate facilities. NAESB could consider establishing standard methodologies for ratings. Develop a standard methodology to rate transmission and/or generator facilities. At a minimum, such a standard could identify a minimum level of acceptable assumptions and relevant industry rating practices.
- Define standard formats and protocols for communication of facility ratings, operating limits and transfer capability.
- Develop a standard methodology for determining system operating limits. The NERC standard requires only that the methodology by which system operating limits are calculated be documented and made available to the compliance monitor, the Reliability Authority and the Planning Authority. In addition, the system operating limits must be made available to transmission service providers, presumably so they can provide transmission service up to the defined limit. The NERC standard does **not** require:
 - The publication, to the market, of the methodology used including an identification of the assumptions used for elements such as generator dispatch and reliability margins. The assumptions used could have significant commercial impacts.

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- The development of a standard methodology to determine what portion of the operating limit is being used at any point in time.
- How the transmission service provider determines the remaining available capability.
- Footnotes to Table 1 of the Draft NERC Standard defining normal and contingency conditions permit system adjustments, includes “curtailments of contracted firm (non-recallable reserved) electric power transfers” to prepare for the next contingency. The methodology to undertake such curtailments should be defined in a business practice standard, as a companion to this reliability standard or in conjunction with another reliability standard.
- Develop a standard methodology to determine transfer capabilities. The transfer capability is defined as “the measure of the ability to move electric power from one area to another over all transmission lines between those areas under specified system conditions”. This definition requires that the adjacent areas coordinate the calculation of the transfer capability, and define and agree on a methodology to incorporate simultaneous transfers. In the event transfers may occur over several lines, a standard methodology to calculate and assess simultaneous transfer feasibility may be required. The NERC standard requires only that the methodology by which transfer capabilities are calculated be documented and made available to the compliance monitor, the Reliability Authority and the Planning Authority. The assumptions used could have significant commercial impacts.

Discussion Issues for Consideration

The SRS identified some concerns regarding development of a NAESB Business Practice Standard to complement the NERC standard.

- What level of standardization is possible given the diverse regional and market methodologies and requirements employed today?
- What level of “granularity” (i.e.- general/broad requirements in a methodology) could a business practice standard be possible?
- What information (ratings) should be provided to the marketplace?
 - How and when should such information be communicated?
- What added value would such a standard provide to the market participants?
- Should NAESB set the numerical levels for ATC?

**Initial Standard Review and Analysis Report
For
NERC Standard 300 - Balance Resources and Demand**

**NAESB WEQ Executive Committee
Standards Review Subcommittee
October 21, 2003**

This initial Standard Review and Analysis Report is intended to provide information for the NAESB Wholesale Electric Quadrant (WEQ) to make informed decisions on the disposition of a proposed standard that impacts the wholesale electric industry. The Standards Review Subcommittee provides this Report as an initial review of a proposed Standard that may impact current or future NAESB Wholesale Electric Quadrant standards. This Report contains no recommendations to develop or propose a NAESB Standard. A White Paper may be developed to propose a NAESB standard if the WEQ finds it necessary.

This **Initial Standard Review and Analysis Report** reviews the following standard(s):

Proposing Organization(s): North American Electric Reliability Council (NERC)

Proposed Standard(s) and date: Standard 300 – Balance Resources and Demand, consisting of the following sections:

- 301 – Balance of Resources and Demand
- 302 – Frequency and Area Control Error
- 303 – Reliability Authority Directives

Description and Background

The objective of this standard is to maintain interconnection scheduled frequency within a predefined frequency profile under both normal and abnormal operating conditions. To accomplish this objective, this standard provides several measures for assessing a Balancing Authority's performance, including control performance, discrete event metric (DEM) and abnormal operations metric (AOM). This standard defines the compliance monitoring process and non-compliance levels for each of these measures. This standard will replace portions of NERC Policy 1, Generation Control and Performance.

This standard will address the following areas:

- the Balancing Authority's (BA) responsibility to control its area control error (ACE)
 - proposed measures of frequency control
 - After the fact long term
 - Control Performance Measure 1 (CPM-1)
 - Control Performance Measure 60 (CPM-60)
 - After the fact intermediate
 - Abnormal Operations Measure (AOM)

- Discrete Event Metric (DEM)
- the Reliability Authority’s (RA) response to frequency deviations not controlled by the BA’s under its control
 - Real Time
 - Frequency Relay Limits
 - Frequency Abnormal Limits
 - Frequency Trigger Limits
- the Balancing Authority (BA) response to Reliability Authority (RA) directives
 - actions the BA is expected to take

This is a very “technical” oriented standard. The drafting team has proposed new performance measures for the industry to consider. Some benchmarking will be required. Finally, note that the drafting team has composed four documents (*Introduction to the Balance Resources and Demand Standard, Procedure for Determining Balancing Authority Frequency Bias, Procedure for Determining Interconnection Frequency Limits, and Procedure for Determining Balancing Authority ACE Limits*) in support of this standard that should also be carefully reviewed.

Requirements deal with the relationship between RAs and BAs that are relevant for purposes of balancing resources to loads in real-time for purposes of maintaining frequency. It is unclear to what extent obligations may need to be extended to resources and loads to provide data or perform operations in a manner as required by the standard. (This needs further clarification from NERC)

Potential business practice standards and related impacts

The proposed standard impacts the following NAESB activities/standards:

- Inadvertent Interchange Payback Business Practice

The proposed standard raises the following possible business practice concerns:

- The standard does not provide detail as to the format of the monthly compliance reports or how such reports are to be delivered (e.g. electronically, via first class mail, etc.). Business practices/standards may be useful to make the data submittal process as efficient as possible.
- Business practice standards may be needed to allow for entities to payback inadvertent energy as identified by the NERC measurements. The existing activities of the NAESB Inadvertent Interchange Payback Task Force complements the current NERC CPS1, and CPS2 measurements that establish triggers or limits as to when inadvertent energy may have been exchanged. Such complementary business practices may be required for these new NERC measures.

Notes/Comments regarding NERC-NAESB Coordination

The SRS discussed the possibility of NAESB complementary business practices to support each of the proposed NERC measures. Several concerns were raised regarding the co-existence of NERC and NAESB standards that relate to balancing and system frequency.

- If NAESB will pursue development of complementary business practice standards to these NERC standards, which standard (NERC or NAESB) will establish the valuation “triggers”, i.e.- when inadvertent is identified as to have been exchanged.
 - Which organization would be responsible to monitor and house the needed data must also be addressed.

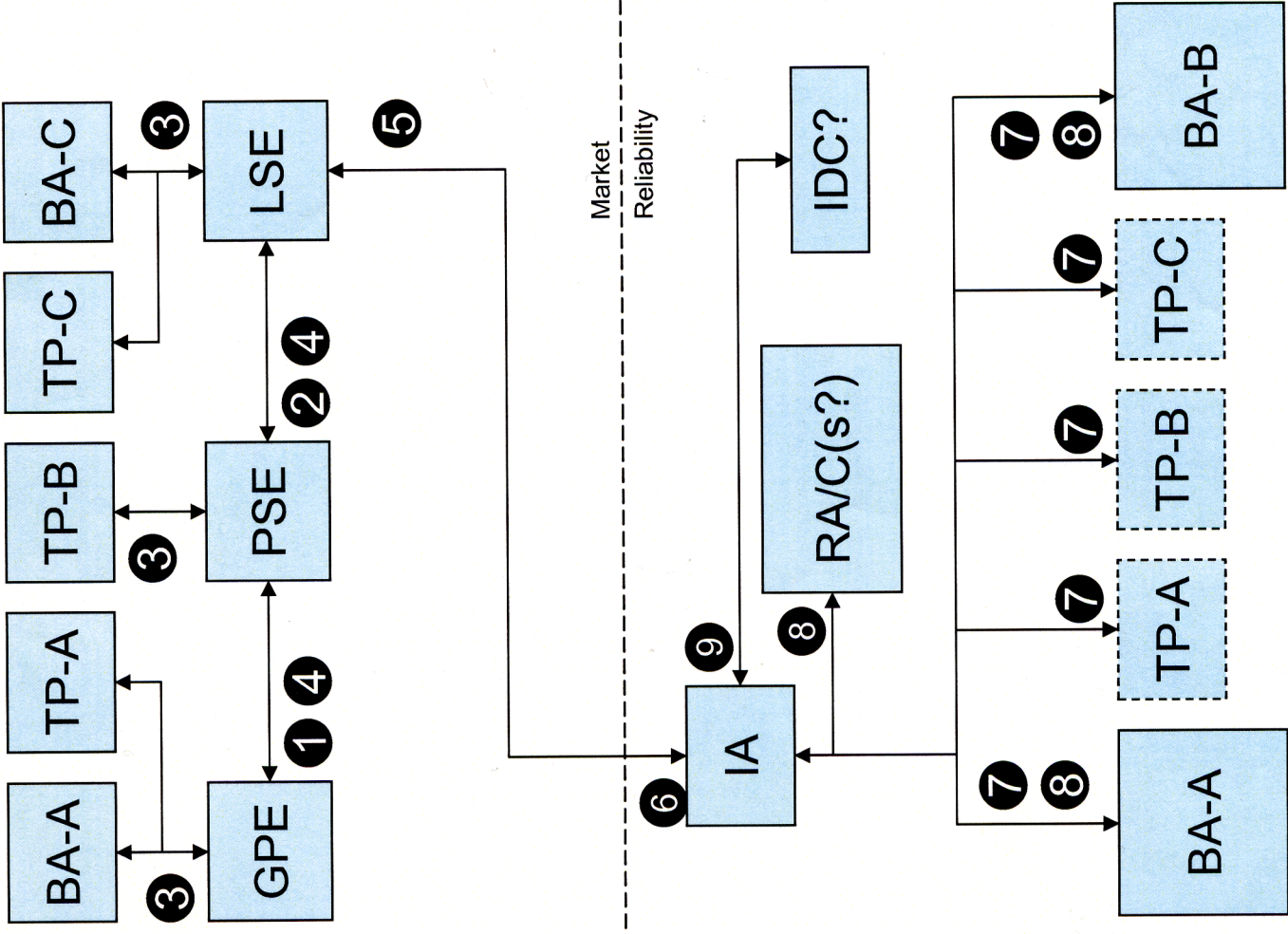
- There was concern that the new NERC compliance (as well as any additional Regional compliance) penalties may be overlaid by payments for inadvertent energy that may be determined by a NAESB standard business practice.
 - There was also concern that certain measures, specifically DCS, may not have any business practice solutions.
 - Generally, the goal of any NAESB business practice, which may be identified as necessary, should be to provide market participants with the correct incentives to behave in ways as to avoid violation of NERC requirements and their resultant penalties.

MARKET SCHEDULING

- 1.) GPE owns a generator in A. He wants to sell. He discusses with PSE2 and PSE2 agrees to purchase, provided that GPE will deliver to B.
 - 2.) PSE2 now sells that generation to LSE. LSE agrees he will pick it up at B.
 - 3.) GPE tells BA-A that he wants to generate. BA-A agrees, and gives GPE an energy ID for the schedule.
 - GPE tells TP-A he wants to export. TP-A agrees, and gives GPE an export ID for the schedule.
 - PSE tells TP-B he wants to wheel. TP-B agrees, and gives PSE an wheel ID for the schedule.
 - LSE tells TP-C he wants to import. TP-A agrees, and gives LSE an import ID for the schedule.
 - GPE tells BA-C that he wants to sink energy. BA-C agrees, and gives GPE an load ID for the schedule.
- Note that this step could be accomplished through entering a bid/offer into a market system or via more "traditional" methods*

- 4.) The GPE and PSE send their Schedule IDs to the LSE so he can write the "Interchange Transaction Request"
 - 5.) The LSE sends the Interchange Transaction Request to the IA
- INTERCHANGE SCHEDULING**
- 6.) The IA reviews the request to make sure it is VALID
 - 7.) The IA verifies that the Schedule IDs are all valid with each BA and TSP. This is done automatically within a few seconds.
 - 8.) The RA/RC verifies that the transaction does not cause any reliability problems. The BAs verify the transaction can still be implemented and that any that the interchange numbers agree.
 - 9.) The IA marks the request as an "Interchange Transaction" and forwards it to the IDC for future reliability coordination.
 - 10.) NOT SHOWN – the BAs turn the Interchange Transaction into an "Interchange Implementation" by entering it into their scheduling systems.

Note that there might be two types of schedule: Fixed and Floating. Fixed would be a traditional set schedule, while Floating might be a price taker source, sink, or both. For example, if A and C are both markets, A might have a bid for "up to 200MW of gen at price x." C might have an offer to "supply up to 500MW at price y." When the markets clear, A might have 150MW and C might have 300MW. In this case, one of four things can happen: 1.) The schedule is set to 150 and LSE has to buy from the C spot market and/or pay imbalance charges, 2.) The schedule is set to 300 and GPE has to buy from the A spot market and/or pay imbalance charges, 3.) The schedule is set at 225 and each buy half from the spot markets and/or pay imbalance charges, or 4.) the schedule is dropped, and does not run.





MEMORANDUM

TO: NERC Board of Trustees

FROM: Roy Thilly, WPPI

DATE: April 17, 2002

SUBJECT: Issue From February 20, 2002 Board Meeting

At the conclusion of the Board of Trustees meeting on February 20, 2002, the Board asked for comments from observers. I did not comment at that time because of time constraints and the need to think through an appropriate response to the Board's actions at the meeting. I am providing my comments now.

I was very pleased by the actions the Board took at the meeting, particularly in asserting responsibility for development, compliance and enforcement of international reliability standards.

I was also pleased that the Board endorsed the concept that there should be uniform methodologies for the calculation of available transmission capacity (ATC), total transmission capacity (TTC), capacity benefit margin (CBM) and transmission reliability margin (TRM), at least within those regions in which the Midwest Independent System Operator does business. I believe it is unfortunate, however, that the Board adopted, as formal NERC planning standards, criteria for these calculations that specifically do not require uniformity among the regions where there are not sound engineering reasons for differences. The standards approved can be, and in fact, have already been, read by some as formally legitimizing adoption of different methodologies by each region, as long as the general criteria in the new standards are met. I assume, however, that the Board's direction to the regions in which the MISO operates indicates an intention to address this issue more broadly.

On reflection, I also believe that before adopting the planning standards at issue, the Board should have explicitly addressed the threshold issue of whether or not a NERC reliability standard on CBM is appropriate at all; that is, should a standard not only define, but also mandate the reservation of CBM as necessary for the reliability of the bulk electric system or is CBM more properly dealt with as a tariff or commercial practices issue. It appears that the answer to this threshold issue was assumed because a standard was proposed. I, and others who have been involved with this issue for years, should have flagged this key premise for the Board's consideration.

It is very important for NERC staff and the Board to focus quickly and carefully on the issue of what constitutes a core reliability standard, as opposed to a business or commercial practice. In the past, NERC has not had to make this distinction and as a result, commercial matters are addressed in NERC standards. This fact is causing confusion among stakeholders and, in my judgment, has resulted in some of the distrust of the NERC process that is apparent.

I question whether the planning standards adopted by the Board on February 20 for CBM and for ATC should be characterized as core reliability requirements. It is clear that to safeguard reliability there must be a way to determine the total transfer capacity of the transmission system and limits must be set on how much the system can be safely loaded up in emergency and non-emergency conditions in order to avoid a risk of major outages. For this reason, a standard that requires calculation of TTC and defines how that calculation should be made on a consistent basis by the entities that control the grid seems to me to be the proper subject of a reliability standard.

TRM is the amount of transfer capability that should be reserved and not sold to account for uncertainties in actual, real-time flows. According to the NERC definition, TRM is the amount of “transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable operation as system conditions change.” Based on this definition, it is appropriate that a NERC standard require that TRM be maintained by transmission providers and define how to calculate it. Thus, I believe that NERC standards should provide for uniform determinations of TTC and TRM, subject to a demonstration that there are engineering differences in certain areas that justify adjustments to the standard calculation methodology. The regions should have the burden to come forward with justifications for any calculation variances when the uniform standard is considered.

CBM is another matter entirely. Capacity benefit margin is an amount of transmission interface capacity held back from the market for the benefit of the utilities with generation on a given transmission system, so that those utilities can use the reserved interface transmission capacity during generation and transmission outages to bring in replacement energy. CBM thus allows a utility to save money by maintaining lower generation reserves than would be necessary absent the transmission set aside.¹ Today there is no charge for reserving CBM, but that issue is squarely before FERC in its standard market design proceeding where staff is proposing that CBM be reserved and paid for by an entity that wants it. CBM has been very controversial because some vertically-

¹ The NERC definition for CBM in the planning standard adopted indicates that CBM is a matter of economics, not transmission system reliability: CBM is “that amount of transmission transfer capability reserved by load serving entities (LSEs), whose loads are located on the transmission provider’s system, to enable access by LSEs to generation from interconnected systems to meet reliability requirements. Preservation for an LSE of CBM 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.” The “reliability requirements” referred to are generation adequacy or reserve requirements that may exist in the regions, under state regulation or in internal utility planning protocols, but are not NERC reliability requirements. These requirements can be met in two ways: by building or contracting for additional generation or by reserving transmission capacity to get back-up from neighbors.

integrated utilities reserve CBM for the benefit of their generating systems and others do not. There also has been considerable variation in how CBM is calculated and utilities can exercise discretion not to reserve CBM if they themselves want to use the capacity to make a firm purchase from the outside. Transmission owner CBM reservations effectively deny competitors access to the reserving entity's system.²

For these reasons, the issue of CBM reservations has been before FERC for a number of years. In an Order issued in Docket No. EL99-46 on July 28, 1999,³ FERC sought to address the issue of the inconsistent and highly discretionary CBM methodologies employed by different utilities by asking NERC to come up with a uniform methodology for calculating CBM by the end of 1999. In issuing this Order, I believe that FERC assumed CBM is a "reliability requirement" approved or imposed by NERC.

In response to this Order, NERC has not been able to persuade the regions, and the transmission providers within the regions who ultimately decide whether to reserve CBM, to agree on a methodology. Given the economic value of CBM reservations and the significant competitive implications of these reservations, this should not be a surprise. Instead, after more than three years, NERC has finally come up with the criteria approved as "standards" at the February 20 meeting, which are designed to circumscribe utility and regional discretion and thereby eliminate some of the egregious problems with discretionary CBM calculations. The criteria themselves are good, but continue to allow each region to have its own methodology,⁴ and do not require utilities within a region to reserve CBM at all. Discretion remains in the vertically-integrated transmission providers as to whether they want to reserve CBM or not. Some of the regional methodologies also include substantial discretion in the calculations themselves.

The fundamental question then is whether the criteria adopted by NERC should constitute an international core reliability requirement or standard, or instead amount to an attempt to impose regulatory conditions on a commercial practice. To my knowledge, NERC itself has never determined that reserving CBM is necessary for the reliable operation of the integrated bulk power system⁵. This is the key threshold issue that should be addressed before any standard is adopted. I would argue that since (i) some regions do not calculate or reserve CBM at all, and (ii) in other regions where CBM is permissible, individual utilities can choose not to reserve it, the reservation of CBM is not a

² Since CBM reservations do not reserve transmission capacity on the system on the other side of the interface at issue, there is real question as to whether a CBM reservation will actually provide a generation reliability benefit since it may not be possible to get the replacement energy to the interface when it is needed.

³ *Capacity Benefit Margin in Computing Available Transmission Capacity*, 88 FERC ¶ 61,099 (1999).

⁴ The fact that there are different CBM methodologies in the regions in the eastern interconnect today is not the result of engineering or physical differences in the system. It is the result of the fact that there are regions. Engineers in the various regions have approached the question from different perspectives and have come up with different methodologies. No particular methodology is "correct." Everyone is in favor of standardization, provided that his or her standard is used.

⁵ The approved standard requires every region to have a CBM methodology, but does not require that anyone use it.

fundamental requirement for reliable operation of the bulk system. Instead, it is a use of transmission that allows a generating system to maintain lower reserves than it otherwise would and thereby improve the reliability of its generation system. While a CBM reservation may increase the reliability of that system, so would adding another generator.

My analysis does not mean that CBM will go away. FERC, in its tariff, allows, and may continue to allow, CBM to be subtracted from TTC-TRM in the calculating of available transmission capacity (ATC) on the ground that the utilities have built transmission and planned for generation back-up in this way. Alternatively, FERC may require CBM to be "paid for by the entity requiring the service, whether it be for additional reliability or access to other resources," as it has proposed in its March 15 Working Paper on Standardized Transmission Service and Wholesale Electric Market Design (at 20). FERC, however, should not labor under the assumption that NERC requires that CBM be reserved and has found that such reservations constitute a core reliability requirement. If FERC continues to permit CBM, the issues undoubtedly will be who pays the cost of CBM and what is a fair process for reservation and use of CBM. These are commercial and tariff issues, not NERC reliability issues. Unfortunately, by punting the issue to NERC in its July, 1999 Order, FERC itself blurred this issue. NERC has failed to clarify the matter by addressing the threshold issue head on. Instead, NERC ostensibly accepted FERC's direction to come up with a uniform methodology even though it does not require reservation of CBM by anyone, but then failed to do so.

It also is questionable that a NERC ATC standard is appropriate. Systems that use LMP pricing must calculate what capacity is available for the sale of financial transmission rights or flowgate rights from time to time, but they may not post ATC continuously or calculate what they offer for sale in the same way that non-LMP systems do, since complexities like "obligation" or "option" rights will need to be dealt with. ATC is simply the number that results from calculating TTC and then subtracting TRM and CBM (where used), as well as capacity that has already been reserved, to find the amount of additional capacity that may be offered commercially. Like CBM, ATC is a commercial or tariff matter. Whether and how ATC is used depends upon market design and should not be a concern of NERC as long as TTC and TRM are properly and consistently determined. In other words, I would argue that NERC does not have to set a standard for ATC once it has covered TTC and TRM.

I believe the confusion over the CBM issue, and the long delay that has occurred in resolving it, demonstrates the need for clear Board and staff leadership in setting the agenda for standards development, rather than leaving key policy issues to stakeholder expert committees like the planning committee. There needs to be a change in culture and approach. Staff's role in the past has been to facilitate committee processes rather than provide recommendations to the Board and the Board has not provided clear policy direction defining what needs to be looked at on a technical basis by groups like the planning committee. Policy direction needs to come from the top down, not be left to committees, if NERC is to act with reasonable dispatch and achieve credibility at FERC. The planning committee's apparent decision not to deal with the threshold issue of whether there should be ATC and CBM NERC standards at all, and its inability to address the uniformity issue after more than three years, have not advanced the objective of achieving mandatory, international, core reliability standards.

November 19, 2003

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Many stakeholders have been very frustrated by the very slow pace of NERC to deal with CBM and similar issues, and its inability to come to conclusion where consensus is not achieved. Clearly, given the evolution of competitive wholesale and retail markets and the move to a standard wholesale market design in the U.S., reliability standards need to be as uniform as possible. NERC loses important credibility at FERC when it adopts "standards" that do not recognize this need. Unfortunately, such actions tend to confirm the preconceptions of some that NERC is controlled by those who wish to slow change or protect incumbent advantages, as CBM can be clearly used to do. There can be little doubt that in a dispute today FERC would look to an RTO like the MISO to determine ATC and CBM on a consistent, neutral basis for commercial purposes and not have much sympathy for different regional methodologies not justified by real engineering differences. Yet, NERC may be perceived as approving just that.

For these reasons, I think that the NERC Board should revisit the planning standards adopted on February 20 immediately and address the threshold issue of whether international standards with respect to TTC, TRM, ATC and CBM are necessary for ensuring the reliability of the bulk system and then direct submittal through the stakeholder process of replacement standards for only TTC and TRM that require uniformity within an interconnection, except where a region has clearly demonstrated that calculation adjustments are legitimate and appropriate based on engineering differences. With respect to CBM, I would strongly urge the Board to inform FERC that there is no NERC requirement that CBM be reserved and that NERC regards CBM as a tariff/commercial issue, not a core reliability requirement. If a region wishes to adopt its own CBM standard or criteria and seek to defend it at FERC, it should do so, but not as a NERC requirement.

cc: Michehl Gent



CALPINE

Attachment B

MEMORANDUM

Date: April 18, 2002

To: NERC Board of Trustees

From: David H. McMillan

Subject: Mr. Thilly's comments to the Board dated 4/17/02

I am taking the opportunity to write in strong support of Mr. Thilly's comments regarding the Planning Committee's actions and performance associated with the topic of total transmission capacity (TTC), available transmission capacity (ATC), transmission reliability margin (TRM), and capacity benefit margin (CBM). I will not attempt to restate arguments that were most eloquently posited by Mr. Thilly's memo on the subject. I will only endorse by reference those arguments and add my voice requesting the Board take specific action in properly identifying CBM and ATC as commercial matters and not core reliability standards as has been suggested by NERC and others to date.

As a representative on NERC's Stakeholder Committee for Independent Power Producers, I can assure you of the truth of Mr. Thilly's suggestion that it is exactly this sort of issue that has led to much of the distrust that exists today in NERC's ability to impartially determine reliability requirements in a way that treats all industry participants fairly and with respect. The Board and NERC can begin to correct this persistent shortfall by embracing Mr. Thilly's challenge and insisting that before a SAR is posted, NERC staff do a critical and thorough assessment in addressing the threshold issue of whether or not a NERC reliability standard is the proper objective for the topic under scrutiny. Only then should NERC committees be permitted to spend time discussing and debating such topics. In addition to a suggested staff review, NERC should institute a process whereby any industry participant can challenge the subject matter of a newly posted SAR if there is a belief that something other than a core reliability standard should be considered. This review and process should be established without delay and should be implemented against the currently posted group of SAR's in order to weed out what appear to some to be largely commercial and not purely reliability issues.

With all the important changes that have impacted and continue to impact our industry (FERC's efforts in RTO formation, FERC's docket on Standard Market Design, an energy bill that may actually pass congress this year, and the appearance of NAESB on the scene) it is time for those of us who remain active in the NERC process to come together and provide the "change in culture and approach" that Mr. Thilly calls for in his memo.

I look forward to our meetings in June where I'm sure we can make significant progress in setting the proper policy direction for the dynamic times within which our industry currently exists.

Executive Summary

The following recommendations to address the OASIS issues listed below have been submitted by the WEQ OASIS 1A Issues Task Force for general approval by the WEQ IT Subcommittee. All issues have been documented and sub-divided into three categories (general issues, compliance/clarification issues, and specification/business practices issues). The goal of this task force is to recommend to the IT subcommittee an appropriate categorization of and resolution process for the twenty (20) OASIS Phase 1A issues listed in this document. A quick overview of the task force recommendations are presented first, followed by more detailed discussion under each specific issue. The numbering system was maintained from the original listing to promote continuity in both sections and the original.

OASIS 1A Issues (Quick Overview)

- 1. Additional Standardization in OASIS Phase 1A** (General)
- 2. GUI Issue/Navigation** (General)
- 3. Output Formats** (Specification)
- 4. INFO.HTM** (Compliance)
- 5. Posting of Schedules** (Compliance)
- 6. TLR & Curtailment Posting** (Compliance, Clarification)
- 7. Posting of Advertisements** (Clarification)
- 8. Upgrade Planning & Progression** (General)
- 9. Responsibility Determination** (General)
- 10. Redirect of Transmission Service** (Specification/Business Practice)
- 11. Recalls of Transmission Service** (Business Practices)
- 12. Multiple Submissions of Identical Transmission Requests / Queuing Issues** (Specification/Business Practice)
- 13. Population of System Data** (Compliance)
- 14. Ancillary Service Requests and Purchases** (Compliance)
- 15. ATC Updates** (Business Practice)
- 16. NAESB Implementation of a Compliance Program** (General)
- 17. Announcing / Posting of OASIS Outages** (Specification)
- 18. This issue originally was one item; now broken into three separate items.**
 - 18(a). Standardized Process for NITS service on OASIS (Use of Status Indicators)**
Part(a) (Compliance)
 - 18(b). Standardized Process for NITS service on OASIS**
Part(b) (Business Practice)
 - 18(c). Standardized Process for NITS service on OASIS (Difference in TP Posting and Capacity)**
Part(c) (Compliance, Clarification)
- 19. Posting Reference Field** (Compliance)
- 20. This issue originally was six items; now condensed down to one item.**
 - 20. Other Items (Naming Standardization)** (Specification/Business Practices)

OASIS 1A Issues

General Issues

1. Additional Standardization in OASIS Phase 1A

Should additional standards be written for OASIS 1A while beginning OASIS Phase II initiatives? (General)

Additional standards should be written and outstanding issues addressed for OASIS Phase 1A. With all the unknowns surrounding OASIS Phase II it makes sense that the WEQ IT Subcommittee becomes involved in enhancing and maintaining the standards for OASIS Phase 1A while developing OASIS Phase II.

2. GUI Issue/Navigation

Over the years there has been debate over the standardization of the HTML interface to OASIS. HTML “look & feel” requirements were intentionally left out of the S&CP.

The overwhelming majority of the OASIS How Working Group opposed the standardization of the HTML interface to OASIS. The reality is that, with the standardization of the CSV templates across OASIS nodes, vendors have the ability to provide a single interface to all OASIS nodes.

The GUI issue may have deeper roots in customer complaints and “free” OASIS usage. In other words, users of OASIS want a single “look & feel” and they want it at no cost.

If standards were made concerning the HTML interface to OASIS, how would they be policed? What would be the scope of these standards? Would providers have the ability to offer a standard interface as well as an enhanced interface? (General)

At this time standardization of the HTML interface would not be beneficial and therefore not needed. With the existence of the current S&CP standards and with compliance issues resolved, standard template queries and responses should allow any Transmission Customer to perform the same functions across many OASIS nodes in virtually identical fashion.

8. Upgrade Planning & Progression

Should OASIS changes be incremental? Who determines if a modification is mandatory or voluntary or both? If a modification is voluntary, how can compliance be monitored? (General)

Anytime an incremental change in OASIS standards is adopted, the change should include a migration and testing plan as part of that standard. Mr. Burden (Williams Gas Pipeline) noted that the Wholesale Gas Quadrant (WGQ) has an Interpretations Subcommittee to resolve issues of standards interpretation. It was suggested that the WEQ employ a similar approach.

9. Responsibility Determination

Who is responsible for the categorization of issues? For example, given an issue, who determines if it is an implementation issue, a compliance issue, or a technical issue? (General)

There was no consensus proposal for this issue. However, for issues identified as OASIS issues, NAESB should be the governing body in determining an appropriate categorization and resolution.

16. NAESB Implementation of a Compliance Program

Should an OASIS Compliance program be implemented? (General)

It was noted that this issue was discussed during the October IT meeting and was determined that NAESB does not perform a compliance function. Further, it was made clear that compliance was a function to be completed by FERC and that FERC does have a hotline established to handle compliance issues.

Compliance/Clarification Issues

4. INFO.HTM

The posting of information in the INFO.HTM file is inconsistent. The availability of the file across providers is also inconsistent.

Should additional standards be written to clarify the information and design of INFO.HTM? How should non-compliance be monitored? (Compliance)

It is clearly specified in the S&CP (3.4, 4.5) as to which documents should be included.

5. Posting of Schedules

There is a need for compliance on the use of the OASIS template “scheduledetail” for queries and responses associated with schedules and curtailments/interruptions (see OASIS S&CP section 4.3.4.1). This is the template where FERC requires information specific to an individual schedule. There is a tendency to use the tag for this information; however, the OASIS data is currently the required source for audit information associated with schedules and curtailments/interruptions. (Compliance)

There is a compliance issue with some Transmission Providers (TPs) not posting this information in the required format as defined by S&CP (4.3.4.1).

6. TLR & Curtailment Posting

There is a need for compliance on use of the OASIS template “security” for queries and responses associated with security events such as curtailments or TLR's (see OASIS S&CP section 4.3.4.2). This is the template where FERC requires information specific to the event, such as facilities involved, start time of the event, etc. Currently, the NERC website provides a central repository for such information associated with the Eastern Interconnection. There is a need to add Western Interconnection information to this repository. (Compliance, Clarification)

There is a compliance issue with S&CP (4.3.4.2) in the way that some TPs post the required events. There is also a compliance issue with some TPs not posting this information in the required format. There also is a clarification or interpretation issue in regards to which events should be posted.

7. Posting of Advertisements

Should the posting of related and/or unrelated advertisements be allowed on OASIS nodes? (Clarification)

S&CP (4.3.10.1, 4.3.10.2) is somewhat vague in this area. A clarification is needed on this issue to more clearly define what types of messages are permissible. Note that this issue is complicated by the fact that many OASIS sites are hosted by external companies and a “hosted by” reference could be viewed as an advertisement.

13. Population of System Data

There is a need for compliance with the S&CP on use of the OASIS template “systemdata” for queries and responses associated with ATC/TTC, etc. (see OASIS S&CP section 4.3.4.4).

This is the template that must be populated in order to meet FERC requirements associated with uploads and downloads of ATC/TTC data. Prior to publication of the S&CP version 1.4, the S&CP required provision of ATC/TTC data through use of the “transoffering” template.

When FERC required CBM data on OASIS, uploads and downloads of CBM were combined with all other system attribute data through the use of "systemdata". At the same time, use of “transoffering” for ATC/TTC data became optional. (Compliance)

S&CP (4.3.4.4) already specifies the use of “systemdata”; thus it appears that some TPs may not be in full compliance with the “systemdata” template.

14. Ancillary Service Requests and Purchases

There is a need for compliance on use of the several ancillary services templates in OASIS for queries and responses associated with the sale and purchase of ancillary services. FERC requires this under Order 889, and as revised. This priority may be lower due to the complexities involved and chaos in the industry associated with ancillary

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services, in addition to the somewhat rigid methodology provided for in the current OASIS S&CP. This will also be a requirement under OASIS II. (Compliance)

Compliance issue, the S&CP (4.3.2.2, 4.3.3.2, 4.3.8, and 4.3.9) already specifies how to handle this type of service. Further enhancements may be required in the development of OASIS Phase II.

18. Standardized Process for NITS service on OASIS (Use of Status Indicators)

Part(a)

Overall problem of misusing the different status indicators, e.g. setting a request to REFUSED because the request was incomplete. There is a need for a uniform interpretation of the S&CP. Specifically, making sure that similar conventions and data definitions are employed on all nodes. (Compliance)

This issue is a compliance issue with S&CP (4.2.10.2) dealing with the misuse of the status indicators.

18. Standardized Process for NITS service on OASIS (Difference in TP Posting and Capacity)

Part(c)

Some providers post things in “blocks” (i.e., an on-peak block), while others post everything in hourly increments (i.e., 24 discrete values). Another might be that some providers respond to a TRANSSTATUS by using CAPACITY REQUESTED and STATUS to allow a customer to derive CAPACITY_GRANTED, while other providers specifically indicate CAPACITY_GRANTED (and some only use CAPACITY_GRANTED if it differs from CAPACITY_REQUESTED).

There are different implementations all have their own unique flavor that have to be coded around. “If PROVIDER =” type statements must be written in order to catch all the node specific implementation details. Obviously you can write exception rules to deal with it, but you shouldn't have to.

If we did some standard queries against all the nodes and compared the data, we'd probably find some interesting differences. If there are valid reasons for the differences, then they should be codified in the S&CP or in Order 638. If not, they should be clarified to ensure uniform interpretation and the nodes modified to meet the clarified S&CP.

The standardization issue above is probably a good idea but it might be a little late unless we see the existence of OASIS according to the S&CP 1.4 continuing more than a couple of more years.

The key question is, is it a matter of S&CP 1.4 implementation (i.e., template access) or is it a really a matter of a TP's tariff (i.e., data content). It would not seem you could

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affect change to the latter (e.g., your reference to “block” vs. hourly), only the first (e.g., element name usage discrepancies).

Many solutions and associated support systems have been built around the different interpretations and implementations as they are today. Some companies may not be inclined to incur the cost to make significant changes, unless a clarified standard is issued.

A submission to FERC would be required since they are the ones responsible for enforcement of the OASIS S&CP. A validation suite should be developed. (Compliance, Clarification)

This issue was identified as a technical clarification issue that needed to be clarified and provided by the WEQ IT Subcommittee.

19. Posting Reference Field

The posting reference is a reference number that must identify the offers being posted on OASIS. The offer posting is in fact a combination of the ATC and the system data, reservations and the price information. When this data is combined to present the offers on the system the posting reference has no real meaning, as it is not clear which of the base items posting identifier is to be used. This worked fine in the past when the system data and the offers were not posted separately. This is a change or a clarification on the purpose of the post ref field. (Compliance, Clarification)

The S&CP provides guidance on the posting reference field in Section 4.3.7.1 and therefore becomes a compliance issue. There also is a clarification issue in that the S&CP references a posting reference field in Section 4.3.10.1, 4.3.10.2, and 4.3.10.3 and the Data Element Dictionary has a definition for two types of posting reference.

Specification/Business Practices Issues

3. Output Formats

Should additional output formats, such as XML, be added to the S&CP? (Specification)

At this time there is not a need for making a massive change in the way output formats are generated. The S&CP standards for OASIS Phase 1A are the accepted way to communicate output formats at this time and does not need changing. Perhaps in OASIS Phase II the potential benefits of XML can be considered. It was suggested that the IT and ESS work jointly on this issue as both a technical and business practices effort.

10. Redirect of Transmission Service

Using OASIS to process and record redirects of transmission service is a difficult task. There are many issues related to the redirect and resale functionality, but most are caused by provider business rules or vendor design choices.

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The primary issue concerns redirects of transmission service. The current OASIS standard does not facilitate primary provider approval of redirected transmission when that redirect is using resold (reassigned) transmission service. When transmission rights are resold to another customer, the customer on the original request is the seller on the resale request. In this case, the primary provider responsible for administering ATC no longer has approval rights for any future transactions, such as REDIRECTS, that use this resold or reassigned transmission service. This is only an issue when the 2nd customer wants to redirect transmission usage to a constrained path. Currently, unless the provider intervenes on the backend, that provider only has the option to deny this type of transaction when it is tagged. (Specification/Business Practice)

This issue, since it is not addressed in the S&CP, is ripe for standardization. It was suggested that the IT and ESS work jointly on this issue as both a technical and business practices effort in specification in OASIS 1A.

11. Recalls of Transmission Service

Recall allows a provider to reduce the capacity or duration of a transmission request. The issue with recalls concerns implementation and may be an issue to address at the provider/vendor level. However, clarification is needed.

When a provider recalls a transmission request that is a REDIRECT, should capacity be returned to the impacted request? When a provider recalls any impacting request type, should capacity be returned to the impacted request? If so, should a provider post reductions for the entire “chain” of requests? (Business Practices)

This issue also is not addressed in the S&CP and needs standardization through business practices process. It was suggested that the IT and ESS work jointly on this issue as both a technical and business practices effort.

12. Multiple Submissions of Identical Transmission Requests / Queuing Issues

OASIS business rules are very similar across most providers. In general, customers submitting transmission request have time periods when they can “queue” their requests. This queue process and the way it relates to the Internet can create issues when customers are “battling” for ATC on constrained interfaces.

Many customers have automated the submission of transmission requests. In order to ensure their place in the queue, these customers schedule these requests to be submitted as a scheduled event. To account for delays caused by the Internet and the nature of web server systems, customers usually submit multiple copies of the same request beginning a few minutes before the top of the hour and lasting until well after the top of the hour.

The issues created by duplicate request submittal are fairly straightforward. Backend systems and the operators working those systems are impacted dramatically. Each request

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that arrives after the top of the hour is a valid request. Therefore, the provider can have hundreds of requests in the queue that will never be confirmed.

Other issues that are created are related to OASIS performance. Anyone using transstatus to retrieve a list of OASIS requests submitted during a time period similar to the one described above can receive hundreds of bogus requests and only a hand full of legitimate requests. Also, while the systems are busy working on the bogus requests, valid requests can be delayed due to bottlenecks created by this issue. Does there need to be a standard to limit these issues? Will FERC Order 605 address this issue? (Specification/Business Practice)

This issue should be worked on as both a technical and business practice modification. This was discussed at length and the discussion revealed this is a very complex issue that needs to be resolved. (Note that the MIPS attempted to address this issue a couple of years ago, but their recommendations were turned down by FERC).

15. ATC Updates

There is a need to revisit the FERC requirement for ATC adjustments and posting updates. In Order 638, FERC requires adjustments to ATC off-line (internally) when the Transmission Provider accepts reservation requests and then on-line, following confirmation, the ATC posting is to be updated. FERC reasoned that use of this two-step method should reduce the number of accepted requests that will be denied service. This methodology tends to encourage delayed acceptance responses from Transmission Providers and has been a trigger for discontent expressed by marketers.

Over the last 3-4 years, there have been significant advances in the automation of backend systems, including calculation of ATC, which interface with OASIS. Revision of ATC postings can be made earlier now and with more certainty than before, so Transmission Providers can avoid the denials of service that once were more frequent due to ATC calculation uncertainties. A pilot project should be designed to test the concerns surrounding denial of service under a one-step method where ATC would only be adjusted upon confirmation. (Business Practice)

While a consensus was not arrived at on this issue it might be noted that the S&CP does not address this issue but Order 889 Part 37.6b and Order 638 does.

17. Announcing / Posting of OASIS Outages

OASIS Outage posting is inconsistent across OASIS nodes. Some nodes send messages to an email list, such as tsin@nerc.com or osc@nerc.com. Other nodes send a message to a list managed by that TSIP.

Section 4.3.10.1 of the S&CP requires providers to post outages “When the OASIS node is out of service and transmission requests are received by the TP by phone or fax.”

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Using the message template, OASIS users can download this information. All other postings of outages are at the discretion of the provider.

The reality is that many providers leave the posting of node outages to the TSIP. Therefore, the provider has the obligation to make sure that the TSIP is posting outage information on the provider's behalf.

The message functionality was added to provide a standard for the posting of specific messages, such as node outage information. All OASIS outages can be posted using this standard and customers will have unilateral access to this data using the message template.

Should additional standards be implemented? How can compliance with this requirement be monitored? (Specification)

There was a consensus that this is a technical compliance and specification issue, but no consensus was reached on a method to include in this recommendation to the IT only that a specification for the notification of outages should be written.

18. Standardized Process for NITS service on OASIS Part(b)

Examples:

Standardized process for NITS service on OASIS:

- a) Initial service application procedure
- b) Designation of network resources
- c) Addition of network resources
- d) Elimination of network resources

(Business Practice)

The enumerated standardization process was identified as a business process issue that should be referred to the ESS.

20. Other Items

1) Naming Standardization

Standardization for items such as service points is a continuing problem in OASIS and should be addressed. (Specification/Business Practices)

This confusion over multiple names for the same physical point(s) has been a long standing issue. The major issue was identified as follows: at a point of interconnect between two providers, how is the point name established and agreed-upon such that the name is used consistently for both parties. It was agreed that this would be both a technical and business process change for the IT and ESS to address.



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TO: NAESB Wholesale Electric Quadrant Inadvertent Interchange Payback Task Force,
Posting for Interested Industry Participants

FROM: Meghan McMillan, NAESB Staff

RE: Draft Minutes from the NAESB Wholesale Electric Quadrant Inadvertent Interchange
Payback Task Force Meeting – November 3, 2003

DATE: November 6, 2003

**Wholesale Electric Quadrant
Inadvertent Interchange Payback Task Force
November 3, 2003 (12:00 p.m. – 5:00 p.m.)
Draft Minutes**

1. Welcome

Mr. Goss opened the meeting and introductions were made. Mr. Cargas gave the antitrust advice. The agenda was adopted absent objection as written. The draft minutes from October 6, 2003 were adopted absent objection as written. [Subsequently during the meeting a motion was made to modify the October 6, 2003 draft minutes and adopt them as modified.]

2. Discussion of L. Goins Motion

Mr. Goins moved, seconded by Mr. Terelmes that the point at which inadvertent interchange ceases to be return-in-kind and becomes a financial settlement be no more stringent than the reliability guidelines established by NERC.

During the discussion phase, Mr. Terelmes stated Control Areas by definition have a responsibility to carry reserves and the IIPTF should not define a way to finance the reserves Control Areas are required to carry, but the task force should attempt to define a means to finance those who need to tap into Control Area reserves in the case of emergencies. Mr. Terelmes added the task force should decide if the scope of this motion falls within this group. Mr. Goss stated his interpretation of the motion is that there would be a dead band limit within which entities would be allowed to pay in-kind, and the dead band limit would be based on reliability guidelines set by NERC. Mr. Goins stated this interpretation was correct. Mr. Blohm stated there cannot be a fixed reliability dead band on any established NERC guideline because NERC standards are not based on an event at a single point in time, they are based on averages.

Mr. Terelmes solicited opinions from other Control Area representatives concerning the feasibility of this motion. Mr. Goss voiced his agreement that a dead band would work, and added that within this dead band entities would pay back inadvertent in-kind and outside the dead band pay back would be financial. Mr. Reed stated his agreement with the dead band method, but suggested the settlement of these issues should still be mutually agreeable. Mr. Green voiced concerns about the issue of the link between reliability and inadvertent payback, and noted that he believes the task force's goal was to develop a method for the financial settlement of inadvertent. Mr. Terelmes noted this motion discusses whether or not the collection within this bandwidth is too stringent and the task force needs to decide if a bandwidth is acceptable and if so it should be designed to prevent voluntary inadvertent. Mr. Blohm suggested the task force evaluate the costs and benefits of developing such a bandwidth.

Mr. Terelmes suggested the task force draft a friendly amendment to the motion containing language about the bandwidth, and noted they should address this issue in such a way that



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participants will not feel doubly penalized while following both NAESB and NERC standards. Mr. Terelmes presented a memo sent to the NAESB office by Mr. Illian commenting on Mr. Goins' motion. The memo stated Mr. Illian would like to propose tabling Mr. Goins' motion pending further research on this issue.

Mr. Terelmes moved, seconded by Mr. Green to table Mr. Goins' motion. The motion was tabled. Mr. Terelmes stated the action items on this tabled motion are the presentations being prepared by Mr. Illian and Mr. Blohm for the next task force meeting.

3. Discussion of tabled motions

Mr. Terelmes suggested the group discuss motions tabled at the last meeting and identify action items for each.

Motion 7: "Whereas IIPTF members cannot be deemed responsible for judging on their own the ultimate economic/market workability of the motions they are voting on, the IIPTF resolved to seek funds from any available government or private source to subject any Standard the IIPTF proposes/agrees on, to rigorous testing at an established economics lab before final adoption by NAESB and submission to FERC."

Mr. Oberski reiterated his opinion that this motion is premature because the standards do not exist yet. Mr. Goss voiced concerns that requesting funds for testing is not within the scope of this task force. Mr. Terelmes stated the task force needs to decide whether this motion is within the scope of this task force or even if NAESB should be responsible for testing these standards. Mr. Terelmes volunteered to discuss NAESB's position on this issue with Ms. McQuade.

Motions 9 & 10: Motion 9: "Whereas the energy price charged for electricity (a) differs between Balancing Authorities and (b) may or may not reflect congestion but (c) does not reflect the Inadvertent Interchange's contribution to frequency control, the IIPTF resolves that the parties to an Inadvertent Interchange of energy be charged or paid for that energy component of their Inadvertent Interchange at their own prevailing energy price (as determined in a separate motion, such as Motion 410), with any excess or deficit of funds "exchanged" accruing to the Interconnection/clearinghouse as adjustments to an operating fund it manages that is financed on the joint faith and credit of the combined Balancing Authority members of the Interconnection, with any distribution of surplus funds made on a pro-rata basis to all the Balancing Authority members of the Interconnection, such as generation-share, load-share, or NERC-defined "bias" share, as may be determined by the IIPTF in a subsequent motion defining "pro-rata."

Motion 10: "Whereas not all Balancing Authorities on an Interconnection have hourly spot markets available to them, the IIPTF resolves that the energy price to be paid or received by a Balancing Authority for the energy component of Inadvertent Interchange during the hour shall be either: (i) "the" hourly spot market price where accessible, or "average" locational price in case of different locational prices within the hourly spot market, otherwise: (ii) the out-of-pocket cost exactly as determined in the FERC Schedule-4 "Balancing Energy" tariff in force inside the Balancing Authority during that hour, but without the 10% penalties in the tariff (that all accrue to the tariff administrator)."

Mr. Green noted the action item for these motions is continued education on the frequency component.

Mr. Lively noted changes he would like to make to the minutes of the October 6, 2003 meeting. Mr. Lively moved, seconded by Mr. Blohm to amend the October 6, 2003 WEQ IIPTF meeting minutes to replace the reference to motion four in motion nine with a reference to motion ten. The motion carried absent objection. [This change is reflected above.]



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Mr. Goss voiced concerns that the following terms contained in motion nine require further definition: "clearing house" and "faith in credit". Mr. Terelmes stated "distribution of surplus funds" needs to be defined as well.

Motion 2: "The IIPTF task force recognizes that inadvertent energy and frequency deviation must be measured before it can be valued. However, the measurement of inadvertent energy and frequency deviation lies outside the scope of the IIPTF and will be a task reserved for NERC. The data received from NERC will be a sufficient measurement of inadvertent energy and frequency deviation and the current hourly data is deemed sufficient until such time that technology allows this data to be more accurate."

Mr. Vandervort voiced concerns about the wording in the last sentence of this motion and suggested the group should modify this motion to replace the word "hourly" with the word "monthly." After extended discussion of this motion, it was decided to modify the motion by striking part of the last sentence. Mr. Terelmes moved, seconded by Mr. Goins to modify motion two to read as follows: "The IIPTF task force recognizes that inadvertent energy and frequency deviation must be measured before it can be valued. However, the measurements of inadvertent energy and frequency deviation lies outside the scope of the IIPTF and will be a task reserved for NERC. The data received from NERC will be a sufficient measurement of inadvertent energy and frequency deviation." The motion passed absent objection.

4. Task force 2003 Evaluation

Mr. Terelmes noted he would like the task force to pursue the goal of drafting standards by the end of 2004, and asked participants to provide input concerning the group's progress to date.

Mr. Goss stated one of the accomplishments of this task force has been to develop a standards request in order to move forward with the development of standards, and there has also been a lot of education and research required in order to better understand the issue of inadvertent settlements. Mr. Blohm noted the components of the inadvertent issue have been distilled and dissected, and added this group has provided a lot of development for the energy component. Mr. Terelmes stated the task force has developed a more solid definition of their goals regarding standards and there have been formal motions made to move the task force closer to drafting standards.

Mr. Terelmes stated he would like to identify clear objectives for 2004. Mr. Goss identified the following issues that he would like the task force to address for 2004: determine a pricing mechanism for energy, develop a recommendation for defining "clearing house", address the dead band issue, develop a methodology for evaluating the frequency component, determine if inadvertent will be settled financially, physically or both, and address the issue of creditworthiness. Mr. Lively stated the task force should decide if reactive power will be considered as the task force addresses inadvertent interchange.

Mr. Terelmes suggested the above issues be addressed in the following order:

- Pricing mechanisms for energy (December)
- Developing a methodology for evaluating frequency control (December)
- Settlement of inadvertent physically and/or financially (January)
- Discussion of the dead band issue (January - February)
- Discussion of reactive power (February)
- Discussion of clearing house
- Discussion of creditworthiness



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5. Calendar of Meetings

Mr. Terelmes suggested the next WEQ IPTF meeting be held on December 10 (9:00 a.m. - 4:00 p.m.) - 11 (9:00 a.m. - 3:00 p.m.) in Houston at the NAESB offices.

7. Adjourn

Mr. Reed moved, seconded by Mr. Goss, to adjourn the meeting on November 3, 2003 at 4:38 p.m. Central.

8. Attendees

Name	Company	In Person/Phone
Bilke, Terry	Midwest ISO	Phone
Black, Shannon	SMUD	Phone
Blohm, Robert	Consulting Economist	In Person
Camp, Yvette	Southern Company	Phone
Davis, Ed	Entergy	Phone
Goins, Larry	TVA	Phone
Goss, Bob	SEPA	In Person
Green, Barry	OPG	In Person
Halpin, Francis	Bonneville Power Admin.	Phone
Lively, Mark	Utility Economics Engineer	In Person
Locke, Greg	North Carolina Power	Phone
McMillan, Meghan	NAESB	In Person
Reed, Tony	Southern Company	In Person
Rosenbergm Marvin	FERC	In Person
Smith, William	Allegheny Power	Phone
Terelmes, Steve	Ameren	In Person
Vandervort, Tom	NERC	Phone

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
36	Congestion Management	Congestion Management Market Coordination	Coordinate Hedging Instruments at Market Interfaces	Coordination of market based congestion hedging instruments, such as FTRs, between adjacent RTOs with markets, especially for out and thru' transactions		59	RTO Market to RTO Market	All RTOs with market	All RTOs with market	Market Rule / Business Practice		Raj Rana - AEP	No	3	
132	Congestion Management	Congestion Management Market Coordination	Joint Re-Dispatch Agreements	Interaction with American Transmission Company; possible joint redispatch agreement among ATC-PJM-Generators on ATC's system			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	K	3	
115	Congestion Management	Congestion Management Market Coordination	Standardize Congestion Management Market Data Exchange	Congestion Management Procedures including reciprocal coordination agreement, exchange of data for real-time and projected operations, SCADA, EMS, Operations Planning and Planning information and models; better granularity, avoid double counting, use of state estimator and LMP to enable RTOs to accurately and consistently quantify flows/impacts outside of NERC IDC to enable RTO to RTO and market to market congestion management to achieve greater efficiencies without calling TLRs; MISO and PJM and expansions to use same methods.	Definition of AFC coordination process between RTOs.		All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	I	1	
35	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	LMP prices at borders of RTOs with markets (Price cap included)			RTO Market to RTO Market	All RTOs with market	All RTOs with market	Market Rule / Business Practice		Raj Rana - AEP	No	3	
68	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Prior to Day Ahead. Secondary Market	To the extent that at a minimum congestion redispatch occurs in an RTO (i.e. a limited energy market), can a method be developed to produce consistent prices at the boundaries? If not, can price discontinuities be tolerated or managed? (Issue I.b.1)					Fundamental approach -- financial hedging issue.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
70	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Day Ahead. Congestion Management Market	If models with identical levels of detail for the West are not used by all three RTOs, do the various simplifications for areas outside any given RTO create problems in achieving a uniform set of redispatch prices? (Issue I.b.3)					Modeling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
72	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Day Ahead. Model spatial granularity	To the extent that at a minimum congestion redispatch occurs in an RTO (i.e. a limited energy market), can a method be developed to produce consistent day ahead prices at the boundaries? (Issue I.b.5)					Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
80	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Day Ahead. Other Scheduling Requirements	To the extent that at a minimum congestion redispatch occurs in an RTO (i.e. a limited energy market), can a method be developed to produce consistent prices at the boundaries that send the same signal to the market? If not, can price discontinuities be tolerated or managed? (Issue I.b.13)					Financial approach -- scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
92	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Market Design - Real Time. Model objective function	How much would a common dispatch interval mitigate against price discontinuities at boundaries? (Issue I.d.2)					Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
62	Congestion Management	Congestion Management Market Coordination		Market Design - Prior to Day Ahead. Financial or Physical	Must the offerings be identical? How can congestion management discontinuities be mitigated? (Issue I.a.3)					Fundamental approach -- financial hedging and scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
63	Congestion Management	Congestion Management Market Coordination		Market Design - Prior to Day Ahead. Option or Obligation	Do different CM models create barriers to trade, and if so, how can these differences be mitigated? (Issue I.a.4)					Fundamental approach -- financial hedging and scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
64	Congestion Management	Congestion Management Market Coordination		Market Design - Prior to Day Ahead. Revenue Stream/ or Offset CM Cost	Must the term of congestion offerings be identical? How can congestion management discontinuities be mitigated? (Issue I.a.5)					Fundamental approach -- financial hedging and scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
129	Congestion Management	Congestion Management Market Coordination		Selection process for market/TLR coordinated flowgates; inclusion of flowgates in PJM FTR/AR auctions; flowgates with and without effective control by markets; updates to flowgate list, phase-in; dispute resolution; let RTO calculate flows outside of IDC and TLR; audit rights; confidentiality of data; consideration of flowgates outside PJM and MISO	Standardized rules for determining flowgates impacted by an RTO.		All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	1	
138	Congestion Management	Congestion Management Market Coordination		Coordination of congestion	Several regional efforts are underway. Coordinate practices and methods between areas with different market approaches.		All	All	All	Business Practice	Yes	Karl Tammar - ISO/RTO Council	No		

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
125	Congestion Management	Determining Control Area Boundaries		Retention of former CAs in the model	When expanding Control Area boundaries (i.e., merging Control Areas) it is necessary to retain "Historic" boundaries for use in NNL estimation or other reasons?		All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	3	
73	Congestion Management	Operate Markets Within Transmission Limits		Market Design - Day Ahead. Model objective function	Who coordinates the scheduling constraints (i.e., security constrained dispatch) on paths that cross RTO boundaries to ensure that inter-RTO schedules do not exceed reliability standards? (Issue I.b.6)					Modeling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
130	Congestion Management	Operate Markets Within Transmission Limits		What happens when MISO and PJM and outside PJM/MISO firm and CBM exceed TTC - day ahead mechanism to reduce oversubscribed conditions			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	2	
43	Congestion Management	Standardize and Coordinate ATC Calculations	Contract Tie Capacity Sharing	Allow Sharing Contract Tie Capacity between Entities across Seams	Lack of Coordination and Sharing of Tie Capacity is an artificial market barrier	27.1, 117, 141	All	All	All	Market Rule / Business Practice	Limited	Carl Monroe, Southwest Power Pool	No	?	
59	Congestion Management	Standardize and Coordinate ATC Calculations	Coordinate Hedging Instruments at Market Interfaces	Inter-control area congestion management / parallel flow management	Develop congestion hedges across control area boundaries.	36	RTO Market to RTO Market	ISO New England	NY ISO		Northeast ISO	Joe Rossignoli - National Grid	G		
44	Congestion Management	Standardize and Coordinate ATC Calculations	Standardize TRM and CBM Calculations	Calculation and Values of TRM and CBM consistent	Underutilization of Transmission Capacity		All	All	All	Market Rule / Business Practice	Limited	Carl Monroe, Southwest Power Pool	No	?	
17	Congestion Management	Standardize and Coordinate ATC Calculations and Postings	Reconcile ATC Calculations Between Physical and Financial Transmission Markets	TTC-ATC calculation/posting	Interface between a financial market (no physical transmission arrangements) and physical transmission regions (selling transmission capacity through OASIS reservations); Problems of TTC-ATC calculations coordination. Counterparties include IMO, NYISO, and ISO-NE.	18, 19 Consolidate	Other	HQ TransEnergie	ISO's	Market Rule / Business Practice	No	Victor Bissonnette - HQ TransEnergie	No		
61	Congestion Management	Standardize and Coordinate ATC Calculations and Postings	Reconcile ATC Calculations Between Physical and Financial Transmission Markets	Market Design - Prior to Day Ahead. Congestion Revenue Rights (CRRs) [Firm Transmission Rights (FTRs) in MD02, FTOs in RTO West]	Are all transmission rights both physical and financial required to be identical to mitigate the seams problems? (Issue #.a.2)					Fundamental approach -- financial hedging and scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
136	Congestion Management	Standardize and Coordinate ATC Calculations and Postings	Reconcile ATC Calculations Between Physical and Financial Transmission Markets	Firm Transmission Service on IMO/MISO	ATC postings between a physical reservation system and a financial reservation system		RTO Market to RTO Market	NPCC	ECAR	Market Rule / Business Practice	No	Barry Green - Ontario Power Gen.	No		
9	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Transmission Calculations	Transmission calculations are not consistent. Solution: Standardized ATC Calculations.		All	Non-RTO Market	Non-RTO Market/ISO Market	Market Rule/Business Practice	Yes - SSG - WI	Steven Cobb - SRP	No		
55	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Improved TTC/ATC posting	Monthly and yearly posting of TTC/ATC values to support transaction pre-scheduling. Clarify how the ATC values calculated by each ISO should be used to ascertain the ability of the interface to support transactions.		RTO Market to RTO Market	ISO New England	NY ISO		Northeast ISO	Joe Rossignoli - National Grid	G		
109	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		ATC Differences - Individual control areas determine ATC for jointly operated transmission interfaces. Differences in ATC calculations can confuse the marketplace, which may react by avoiding transactions that would otherwise be economic due to the uncertainty and perceived risk.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	
116	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		ATC/AFC Coordination - MISO and PJM to coordinate with any external parties wishing to do so, respecting all significant flowgates external to their respective boundaries; availability and levels of service and curtailments for firm and non-firm, network and point to point.			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	No	2	
20	Congestion Management	Standardize TCC Calculations Across Interfaces		TTC coordination	Disagreement between two operators on the physical capability of an interconnection (line 7040 and Phase II). Counterparties are NYiso and ISO-NE.	21 Consolidate	Other	HQ TransEnergie	NYiso	Market Rule / Business Practice	Yes	Victor Bissonnette - HQ TransEnergie	No		NERC
69	Congestion Management	System Market Modeling Coordination	Standardize Prices at Market Interfaces	Market Design - Day Ahead. Energy Spot Market	In order to achieve a uniform set of redispatch prices, if that is necessary, do the network models have to be identical, with the exact system? Each time each one is used does it have to be synchronized with the other RTOs or is a single process required? In addition do the programs that use the models have to be identical in order to get the uniform set of redispatch prices? (Issue I.b.2)					Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
47	Congestion Management	System Market Modeling Coordination		Operational Model Updates	Areas must have up to date models for operational use of other areas across the seam		All	All	All	Physical	Limited	Carl Monroe, Southwest Power Pool	No	?	
75	Congestion Management	System Market Modeling Coordination		Market Design - Day Ahead. Model objective function	Does the use of both AC and DC OPFs introduce compatibility problems? (Issue I.b.8)					Modeling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
121	Congestion Management	System Market Modeling Coordination		Market flow data - reflect ISN and SDX data	Standardize inputs to estimation of power flows (i.e., GLDFs, outages, etc...).		All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	3	
123	Congestion Management	System Market Modeling Coordination		GDLF calculation	Standardized methodology for determining distribution factors - standard OPF model for each interconnection?		All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	?	
135	Congestion Management	System Market Modeling Coordination		Historic>NNL values should not be reflected indefinitely in the future, and an appropriate mechanism to rationalize the historic flows to recognize eventual market conditions should be developed			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	2	
133	Congestion Management	Transmission Market Design	Redispatch of Generation	Define "RTO area wide dispatch"	AJR - This refers to centralized dispatch across a RTO Footprint, rather than within a CA Boundary.		All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	1	
110	Congestion Management	Transmission Market Design	Transmission Market Manipulation	ATC Manipulation - Market participants schedule transactions day-ahead and beyond with no intent to deliver energy. Cancellation in real-time by a market participant results in unused ATC, ramp capability that cannot be used by other market participants. Valuable capability is left unused.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	
53	Congestion Management	Transmission Market Design	Transmission Service Product Type Priority	CAISO ETC rights scheduling - Contract Reference Number	CAISO uses Contract Numbers to track ETC rights. This causes Phantom Congestion and does not allow ETC rights holders to sell and schedule their transmission	14, 16, 94, 95, 141, 142	CAISO Market to Non CAISO market	Non ISO market	CAISO market	Market rule/Business practice/ CAISO software	No	Robert D. Schwermann - SMUD	No		
88	Congestion Management	Transmission Market Design	Transmission Service Product Type Priority	Market Design - Day Ahead. Centralized Unit Commitment.	Does a recallable physical right conflict with a redispatch set in a day-ahead clearing process? (Issue I.b.21)					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
98	Market Design	Energy Market Design and Coordination	Demand Side Energy Market Coordination	Market Design - Post Real Time. Settlement stages	How does bidding or demand-side response between or among RTO's affect the scheduling and dispatch of obligations within the RTO's? Can these kinds of trades between RTOs be accommodated? Does trade of these services between RTOs have implications for either the exporting or importing RTOs ability to meet reliability criteria? (Title to power needs to be established) (Issue II).					Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
90	Market Design	Energy Market Design and Coordination	Hour Ahead & Real-Time Energy Market Coordination Across Market Interfaces	Market Design - Hour Ahead. Timing	How does hour-ahead market integrate with neighbors who do not have hour-ahead process? (Issue I.c.2)					Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
91	Market Design	Energy Market Design and Coordination	Hour Ahead & Real-Time Energy Market Coordination Across Market Interfaces	Market Design - Hour Ahead. Energy Market, Congestion Management Market, and Ancillary Services Market	Is it necessary to align real time markets? If so, can a method be developed to produce consistent real-time prices at the boundaries? (avoid an price discontinuity due to separate calculation of prices with different information.) (Issue I.d.1)					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
93	Market Design	Energy Market Design and Coordination	Hour Ahead & Real-Time Energy Market Coordination Across Market Interfaces	Market Design - Real Time. Dispatch interval	Can a method be developed to produce consistent real-time prices at the boundaries? (avoid an price discontinuity due to separate calculation of prices with different information.) If not, can discontinuities be tolerated or managed? [This may be more of a settlements issue than a consistency issue.] (Issue I.d.3)					Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
131	Market Design	Energy Market Design and Coordination		Express sunset provisions for implementation of Day 2 markets			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	1	
113	Market Design	Green Power Market		Green power attributes trading			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	No	3	
96	Market Design	Market Settlement Systems	Energy Market Settlement Process at Market Interfaces	Market Design - Real Time. Penalties	Do settlement systems have to be common as long as price discontinuities at the boundaries are managed? (Issue I.e.1)					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
97	Market Design	Market Settlement Systems	Energy Market Settlement Process at Market Interfaces	Market Design - Post Real Time. Settlement stages	How are inter-RTO settlements managed? (Includes the revenue adequacy issues related to achieving consistent prices.) (Issue I.e.2)					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
86	Market Design	Transmission Ancillary Service Market Design and Coordination	Ancillary Service Auction Coordination	Market Design - Day Ahead. Ancillary Service Market	All three propose auctions: Do the auctions have to be identical? Is it possible to use price exchange (say as imputed bids) in connection with interactive calculation to minimize the spread between the A/S auctions? (Issue I.b.19)					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
81	Market Design	Transmission Ancillary Service Market Design and Coordination	Ancillary Service Prices at Market Interfaces	Market Design - Day Ahead. Congestion Prices.	Can a "best practice" model for definition and acquisition of ancillary services products be developed to produce consistent prices at the RTO boundaries? (Issue I.b.14)					Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
16	Market Design	Transmission Ancillary Service Market Design and Coordination	Reactive Power Compensation	Compensation for Reactive Power	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.	14, 141, 142, Split - Trans/Gen	All	All	All	Market Rule / Business Practice and Physical	Yes / IIPTF	Mark Lively - Lively Utility	A - C	1	NAESB IIPTF
85	Market Design	Transmission Ancillary Service Market Design and Coordination	Transmission Service Requirements for Ancillary Service Delivery	Market Design - Day Ahead. Ancillary Service Market	Does the RTO of the A/S seller recognize the transmission capacity reservation required to enable the reserves to respond for outages in the RTO of the buyer? (Issue I.b.18)					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
74	Market Design	Transmission Ancillary Service Market Design and Coordination		Market Design - Day Ahead. Model objective function	What is the effect of linking energy and ancillary service markets in the optimizations on model coordination issues? (Issue I.b.7)					Financial approach -- scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
83	Market Design	Transmission Ancillary Service Market Design and Coordination		Market Design - Day Ahead. Ancillary Service Market	When ancillary services are provided from within one RTO for another RTO, does the providing RTO recognize them as obligations within the seller's RTO? (Issue I.b.16)					Fundamental approach -- scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
84	Market Design	Transmission Ancillary Service Market Design and Coordination		Market Design - Day Ahead. Ancillary Service Market	How can AS bids be coordinated across three markets to avoid both double counting and inefficient limitations on bids? (Issue I.b.17)					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
87	Market Design	Unit Commitment Procedure Standardization		Market Design - Day Ahead. Acquisition Mechanism	Does unit commitment need to be standardized? Is this an area where each RTO can have its own method, which matches its resource mix and system responsiveness? (Rapid response of hydro gen. versus lead time requirements for thermal gen.) (Issue I.b.20)					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
13	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for Unscheduled Flows of Electricity	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.	14, 16	All	All	All	Market Rule / Business Practice and Physical	Yes / IIPTF	Mark Lively - Lively Utility	A - C	1	
15	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for Loop Flow	Lack of compensation lessens incentives for operators to solve problems and for accountants to spend money on metering.	14, 16	All	All	All	Market Rule / Business Practice and Physical	Yes / IIPTF	Mark Lively - Lively Utility	A - C	1	
29	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Allocation of transmission capacity on reciprocal flow gates amounts to transmission service without compensation. Legitimizes "parallel loop flow".		14, 16, 43, 117, 141	RTO Market to RTO Market	MISO	PJM	Market Rule / Business Practice		Dave Nick - DTE Energy	E		
66	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Market Design - Prior to Day Ahead. Duration	How will rights for loop flows (non-contract flows) in other RTOs be allocated/acquired? (Issue I.a.7)					Fundamental approach -- financial hedging issue.	SSG-WI, CMA Work Group in PJM/MISO	Syd Berwager - Bonneville PA	No		
134	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for parallel flows			All	PJM	MISO	Market Rule / Business Practice	Jeff Mueller (PSEG), and Andy Rodriguez (PJM) Whitepaper		J	2	
142	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Pricing for native load loop flow impacts		14, 16, 94, 95	All	Eastern Inter-connection	Eastern Inter-connection	Business Practice	No	Ed Davis - Entergy	No		
77	Market Monitoring/ Compliance	Anti-Gaming Coordination		Market Design - Day Ahead. Schedule Components	Will different RTO congestion management systems enhance opportunities for gaming or affect generation dispatch efficiency? (Issue I.b.10)					Financial approach -- scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
11	Market Monitoring/ Compliance	Market Monitoring Entity Requirements		Market Oversight	New and mature markets need oversight to ensure that existing rules are complied with and new rules are adequate in meeting the scenarios they were designed to govern. Solution: Independent Market Auditor or Monitor.	Hold	All	Non-RTO Market/ISO Market	Non-RTO Market/ISO Market	Market Rule/Business Practice	Yes - SSG - WI	Steven Cobb - SRP	No		
94	Market Monitoring/ Compliance	Penalty/Sanction Coordination		Market Design - Real Time. Imbalance Price	Do penalties need to be the same in each RTO? (Issue I.d.4)	14, 16				Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
95	Market Monitoring/ Compliance	Penalty/Sanction Coordination		Market Design - Real Time. Penalties	Will inconsistent imbalance penalty practices hamper non-dispatchable resource sales across RTO boundaries? (Issue I.d.5)	14, 16				Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
3	Market Standards	Energy Market Standard Product Definitions		Definition & treatment of Firm/nonfirm Power	Annual Plan Item 4ci moved from MOS		All	All	All	Market Rule / Business Practice	No	Lou Oberski - Dominion Energy	No		
10	Market Standards	Energy Market Standard Product Definitions		Energy Products	Entities have disagreements concerning the definitions of various energy products. Solution: Standardized Energy Products.	25, 34, 111, 139	All	Non-RTO Market	Non-RTO Market/ISO Market	Market Rule/Business Practice	Yes - WECC	Steven Cobb - SRP	No		
25	Market Standards	Energy Market Standard Product Definitions		Need for common physical market and products - regional variations permitted		10, 34, 111, 139	All	All	All	Market Rule / Business Practice	No	Linda Horn - WE Energies	No		Page 4

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
34	Market Standards	Energy Market Standard Product Definitions		Clarification of Product Definitions	Complete/Standard definitions for Liquidated Damages (LD), "Intro", etc.	10, 25, 111, 139	All	All	All	Market Rule / Business Practice	No	Tony Reed - Southern	No		
139	Market Standards	Energy Market Standard Product Definitions		Standard definition of energy products	Energy products and services have common attributes in all markets. Standards definitions will improve efficiencies in communicating and operating between areas with various market designs	10, 25, 34, 111	All	All	All	Business Practice	Yes	Karl Tammar - ISO/RTO Council	No		
7	Market Standards	Market Standard Communication Protocols and Transparency		Market Price Information	Market pricing methodology not comprehensive, consistent or dependable. Solution: Standardized Indices, Independently Managed.		Non-RTO Mkt to Non-RTO Mkt	Non-RTO Market	Non-RTO Market	Market Rule/Business Practice	No	Steven Cobb - SRP	No		
42	Market Standards	Market Standard Communication Protocols and Transparency		Data Visibility	Inability to view neighboring markets information through a common software such that this sometimes hinders Market Participants ability to complete business in a timely fashion.		All	NYISO	RTO	Market Rule / Business Rule	Yes	Marjorie Perlman - Energy East	No		
52	Market Standards	Market Standard Communication Protocols and Transparency		Confidentiality of Data and Information Shared	Standards of Confidentiality would enhance the capability to resolve data sharing and information posting	42	All	All	All	Market Rule / Business Practice	Limited	Carl Monroe, Southwest Power Pool	No	?	
71	Market Standards	Market Standard Communication Protocols and Transparency		Market Design - Day Ahead. Model spatial granularity	To what extent do RTOs need to see other RTOs' scheduling information? (Issue I.b.4)					Modeling issues.	SSG-WI, CMA Work Group	Syd Serwager - Bonneville PA	No		
140	Market Standards	Market Standard Communication Protocols and Transparency		Standard messaging protocols for market notifications	Market participants will benefit from common messaging protocols.		All	All	All	Business Practice	No	Karl Tammar - ISO/RTO Council	No		
1	Market Standards	Market Standard Operating Time		Non Standard Time Zone	The lack of a standard Time Zone causes Market Inefficiencies		All	All	All	Market Rule / Business Practice	No	Phil Cox - AEP	No		
137	Market Standards	Market Standard Operating Time		Inconsistent Market Event Timelines	Timing issues between bid based markets (one example only - not knowing whether your bid has been accepted in "sink" market before having to commit in the "source" market).		RTO Market to RTO Market	IMO	NYISO	Market Rule	No	Barry Green - Ontario Power Gen.	No		
14	Market Standards	Physical and/or Financial Resolution of Inadvertent Interchange		Compensation for Inadvertent Interchange	Lack of compensation lessens incentives for operators to solve problems. Explicit compensation for inadvertent interchange is necessary for appropriate definition of other products, in that such compensation ensures that the defined product is delivered.	16, 53, 94, 95, 141, 142	All	All	All	Market Rule / Business Practice and Physical	Yes / IIPTF	Mark Lively - Lively Utility	A - C	1	NAESB IIPTF
111	Market Standards	Transmission Ancillary Service Market Design and Coordination	ICAP Market Standardization	Capacity Market - Differences in ICAP definitions, requirements, deliverability, and recall procedures have hampered the ability of suppliers to sell ICAP between Northeast ISOs (include regional resource adequacy model, external 30-minute reserves participation, harmonize demand response programs)		10, 25, 34, 139	Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	
46	Planning	Transmission Expansion and Generator Interconnection Coordination	Generator Interconnection - Affected Systems	Generation Interconnection Studies	Generation Interconnections close to seam affects both areas	114, 57	All	All	All	Physical	Limited	Carl Monroe, Southwest Power Pool	No	?	FERC
57	Planning	Transmission Expansion and Generator Interconnection Coordination	Generator Interconnection Transmission Requirements	Transmission interconnection procedures	Need consistent approach to treating merchant generation interconnection procedures with transmission	46, 114	RTO Market to RTO Market	ISO New England	NY ISO		Northeast ISO	Joe Rossignol - National Grid	G		FERC
114	Planning	Transmission Expansion and Generator Interconnection Coordination	Interregional Transmission Planning Procedures	Coordination of interregional planning including transmission facilities and generator interconnection procedures			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	1	FERC
26	Planning	Transmission Expansion and Generator Interconnection Coordination	Transmission Expansion Cost and Construction Responsibilities	Transmission expansion planning - coordination between systems and determine who is obligated to build and pay for improvements	Being reviewed by PJMMISO.		All	All	All	Market Rule / Business Practice	Yes	Linda Horn - WE Energies	No	1	FERC
48	System Reliability	Emergency Operations	Computer Failures	Communication of Computer Failures	Needed for reliable operations and emergency operations		All	All	All	Physical	Limited	Carl Monroe, Southwest Power Pool	No	?	NERC
49	System Reliability	Emergency Operations	Emergency Operating Procedures for Market Interfaces	Emergency Procedures	Emergency procedures require operations across seams	118	All	All	All	Physical	Limited	Carl Monroe, Southwest Power Pool	No	?	NERC
128	System Reliability	Emergency Operations	System Monitoring and Contingency Plans	Contingency plans; critical path analysis		14, 16	All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	2	NERC
118	System Reliability	Emergency Operations	System Restoration Procedures	Emergency and Restoration Plans - operating procedures for Voltage Collapse and Stability		46	All	PJM	MISO	Market Rule / Business Practice	Included in Attachment A of MISO and PJM Reliability Plans	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	I	2	NERC
122	System Reliability	Functional Model		Control area - control zone responsibilities vs. market operator			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	1	NERC

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
50	System Reliability	Generation-Load Balance	Interchange Schedule Ramping Requirements	Schedule Ramp Management	Ramping standard differences across the seams hinder business	108	All	All	All	Market Rule / Business Practice	Limited	Carl Monroe, Southwest Power Pool	No	?	NERC
108	System Reliability	Generation-Load Balance	Interchange Schedule Ramping Requirements	Failure of Transactions due to Ramping of Control Area Interchange - Desirable transactions between control areas may be "blocked" from access to the grid due to insufficient dispatch capacity to absorb large schedule changes while maintaining energy/load balance within the control area.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	2	
51	System Reliability	Generation-Load Balance	Inter-Market Resource Requirements	Resource Adequacy	Parties in one area rely on resources in other areas. Validation of their reliance on the other area must be coordinated.	May need to be subdivided, 5	All	All	All	Physical	Limited	Carl Monroe, Southwest Power Pool	No	?	NERC
27	System Reliability	Inter-Market and Intra-Market Facility Outage and Maintenance Coordination		Outage Maintenance Coordination	Being reviewed by PJM/MISO. See PJM presentation "Status Report to FERC on July 31, 2002 Alliance Order" dated Jan 2003, page 6 as posted under NAESB WEQ Seams subcommittee July 8 date	45 (was #27.5)	All	All	All	Market Rule / Business Practice	Yes	Linda Horn - WE Energies	D	?	
45	System Reliability	Inter-Market and Intra-Market Facility Outage and Maintenance Coordination		Coordination of Transmission and Generation Outages	Both forced and planned outages	27.5	All	All	All	Physical	Limited	Carl Monroe, Southwest Power Pool	No	?	NERC
120	System Reliability	Inter-Market and Intra-Market Facility Outage and Maintenance Coordination		Facilities in close electrical proximity under different RTOs - outage maintenance coordination, access and expansion planning			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	1	NERC
30	System Reliability	Operate Markets Within Transmission Limits		Market allocations over flow gates are approved without regard to flow gate capacity resulting in over subscription of flow gates.			RTO Market to RTO Market	MISO	PJM	Market Rule / Business Practice		Dave Nick - DTE Energy	E		NERC
99	System Reliability	Operating Reserves/Resource Adequacy	Energy and Reactive Capacity Reserve Requirements	Demand Response Participation.	If there is an RTO capacity requirement for all RTOs, how will double-counting across RTOs be avoided? Note: RTO West and WestConnect are not currently proposing a resource adequacy requirement independent of the requirement for balanced schedules. (Issue X.1).					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
100	System Reliability	Operating Reserves/Resource Adequacy	Energy and Reactive Capacity Reserve Requirements	Resource Adequacy. Resource Adequacy Assessment.	If there is an RTO capacity requirement for all RTOs, do different resource adequacy approaches result in different penalty structures and if so, does this create problems, e.g., opportunities for arbitrage? Note: RTO West and WestConnect are not currently proposing a resource adequacy requirement independent of the requirement for balanced schedules. (Issue X.2).					Other issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		NERC
119	System Reliability	Operating Reserves/Resource Adequacy	Energy and Reactive Capacity Reserve Requirements	NERC Regional Criteria and Reserve Sharing - define operating policy changes, waivers, or certifications that are needed to permit security-constrained dispatch over multiple existing control areas to allow flows not to be tagged; Joint Reliability Coordination - NERC Policies 5 and 9			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	2	NERC
82	System Reliability	Operating Reserves/Resource Adequacy	Reliability Aspects of Inter-Market Scheduling of Ancillary Services	Market Design - Day Ahead. Ancillary Service Market	How does bidding of ancillary services between or among RTOs affect the scheduling and dispatch obligations within the RTOs? Can this kind of trade between RTOs be accommodated? Does trade of these services between RTOs have implications for either the "exporting" or "importing" RTO's ability to meet reliability criteria? (Issue I.b.15)					Market issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
107	System Reliability	Transaction Curtailments	Market Impacts of Transaction Curtailments for Reliability Reasons	Transaction Curtailment - Transaction curtailments for security may extend beyond the reliability need due to differences in market timing. Extended curtailments are disruptive to both the marketplace and the reliable operation of the grid.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	NERC
126	System Reliability	Unscheduled/Parallel Path Flow Management	Interchange Distribution Calculator Requirements	Definition of coordination between market entity (PJM or MISO) and the IDC; define necessary changes to IDC; updates of base cases and book of flowgates			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	1	
127	System Reliability	Unscheduled/Parallel Path Flow Management	Interchange Distribution Calculator Requirements	Industry oversight and reporting of PJM and MISO impact calculations - IDC cost, cost allocation to reimburse NERC			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	3	

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
23	System Reliability	Unscheduled/Parallel Path Flow Management	Parallel Path/ Unscheduled Flow Monitoring and Operation	How different congestion management methodologies will interact to ensure parallel flows and impacts are recognized and controlled to ensure system reliability.	Being reviewed by PJM/MISO.	115	All	All	All	Physical	Yes	Linda Horn - WE Energies	No	1	
24	System Reliability	Voltage Control		Voltage Operating Procedures	Being reviewed by PJM/MISO. See PJM presentation "Status Report to FERC on July 31, 2002 Alliance Order" dated Jan 2003, page 6 as posted under NAESB WEQ Seams subcommittee July 8 date	(was #27.4)	All	All	All	Market Rule / Business Practice	Yes	Linda Horn - WE Energies	D	2	
5	System Reliability	Operating Reserves/Resource Adequacy	Energy and Reactive Capacity Reserve Requirements	Provision of reserves across multiple control areas	Annual Plan Item 4cii moved from MOS	51	All	All	All	Market Rule / Business Practice	No	Lou Oberski - Dominion Energy	L		
39	Transaction Scheduling	Controllable Line Scheduling		Controllable Line Scheduling	Concept of operations for general methodology to schedule controllable lines between RTOs. Being reviewed by NYISO	58	All	NYISO	RTO	Market Rule / Business Rule	Yes	Marjorie Perlman - Energy East	No		
58	Transaction Scheduling	Controllable Line Scheduling		Controllable line scheduling	Concept of Operations for general methodology to schedule controllable lines has been drafted. A multi-ISO stakeholder group (similar to JCAIG) needs to be formed to review the draft Concept of Operations to provide stakeholder input.	39, 60	RTO Market to RTO Market	ISO New England	NY ISO		Northeast ISO	Joe Rossignoli - National Grid	G		
60	Transaction Scheduling	Controllable Line Scheduling		Cross-border price convergence	The lack of price convergence at the control area boundaries may inhibit the desire of market participants to arbitrage between neighboring markets. This issue is being referred to the individual ISO Market Committees for further definition on the business issue that needs resolution.	58	RTO Market to RTO Market	ISO New England	NY ISO		Northeast ISO	Joe Rossignoli - National Grid	G		
12	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Develop Electronic Scheduling	Interchange/Intrachange Scheduling Data Exchange	Current E-Tagging process is inadequate for exchanging reliability and market data within the Western Interconnection. Solution: Electronic Scheduling		All	Non-RTO Market/ISO Market	Non-RTO Market/ISO Market	Market Rule/Business Practice	Yes - WECC	Steven Cobb - SRP	No		
41	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Inter-Market Ramping Requirements Standardization	Scheduling Coordination (including Ramp Rates)	RTOs have different ramp rates and scheduling requirements that require Market Participants to complete multiple submissions for the same transaction.		All	NYISO	RTO	Market Rule / Business Rule	Yes	Marjorie Perlman - Energy East	No		
79	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Standardize Inter-Market Scheduling Timelines	Market Design - Day Ahead. Other Scheduling Requirements	Should the time intervals and submission times be synchronized to mitigate obstacles to inter-RTO trade? (Issue I.b.12)					Financial approach -- scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
78	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Tools and Procedures to Accommodate Inter-Market Interchange Scheduling Requirements	Market Design - Day Ahead. Schedule Components	Can tools be developed for scheduling submission that assist the user in meeting any differences in protocols between RTOs? (Issue I.b.11)					Financial approach -- scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
8	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Scheduling	Inconsistent procedures among entities. Solution: Western Interconnection Standardized Interchange Scheduling Protocols.		RTO Market to Non-RTO Market	Non-RTO Market	ISO Market	Market Rule/Business Practice	Yes - SSG - WI	Steven Cobb - SRP	No		
76	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Market Design - Day Ahead. Model objective function	Do differences in the scheduling requirements (e.g., requirements for balanced schedules) between RTOs create seams problems for inter RTO schedules? If so, can these problems be mitigated? (Issue I.b.9)					Modeling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
104	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Transmission Checkout Failure - Operators curtail transactions due to mismatched tag data, different MW volumes, etc. The curtailment of transactions due to data incompatibility is disruptive to both the marketplace and the reliable operation of the grid.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	
106	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Transaction Scheduling - Inconsistent information and market timing rules lead to uncertainty and risk that discourage the scheduling of some inter-regional transactions.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	
32	Transmission Service	Transmission Market Design	Transmission Service Product Type Priority	MISO- PJM market allocation will give preference to the market as Network over PTP even though the Market allocation may be a non paying transmission customer.			RTO Market to RTO Market	MISO	PJM	Market Rule / Business Practice		Dave Nick - DTE Energy	E		
40	Transmission Service	Transmission Market Standard Product Definitions and Priorities	Multiple Proxy Bus Development	Multiple Proxy Buses for Free Flowing Interfaces	Development of multiple proxy buses between RTOs for scheduling and pricing.		All	NYISO	RTO	Market Rule / Business Rule	Yes	Marjorie Perlman - Energy East	No		
4	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Definition & treatment of Firm/nonfirm Transmission	Annual Plan Item 4cii moved from MOS		All	All	All	Market Rule / Business Practice	No	Lou Oberski - Dominion Energy	No		
103	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Transmission Service - Market participants require consistent treatment of transmission products across multiple control areas to reduce perceived market risk, scheduling confusion and uncertainty.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H		

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
124	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Wide area dispatch and network resources to network loads - resource deliverability if not a firm network load			All	PJM	MISO	Market Rule / Business Practice	In PJM/MISO Congestion Management Proposal Whitepaper	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	J	3	
141	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Replacement of contract path with flow-based transmission service		14, 16, 94, 95	All	Eastern Inter-connection	Eastern Inter-connection	Business Practice	No	Ed Davis - Entergy	No		
54	Transmission Service	Transmission Service Pricing	Discounting of Market Interface Transmission ATC	Transmission service charge discounting	Ability for TOs to discount TSC rates on external interfaces to selectively reduce export charges and encourage use of ties. The software exists, however, there does not appear to be any business incentives to exercise discounts.		RTO Market to RTO Market	ISO New England	NY ISO		Northeast ISO	Joe Rossignoli - National Grid	G		
22	Transmission Service	Transmission Service Pricing	Market Interface Transmission Service Pancaking	Rate pancaking elimination	Being reviewed by PJM/MISO.	38, 105	All	All	All	Market Rule / Business Practice	Yes	Linda Horn - WE Energies	No	1	FERC
38	Transmission Service	Transmission Service Pricing	Market Interface Transmission Service Pancaking	Rate Pancaking	Charges to Market Participants who conduct business over more than one RTO. Reciprocal agreements needed to eliminate these charges. NYISO and ISO-NE		All	NYISO	RTO	Market Rule / Business Rule	Yes	Marjorie Perlman - Energy East	No		
105	Transmission Service	Transmission Service Pricing	Market Interface Transmission Service Pancaking	Export Charges (Pancaking) - Control-area specific export charges remove incentives to transact business when transaction margins are of the same magnitude or less than the prevailing export charges. Such charges include transmission and ancillary service components.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	
117	Transmission Service	Transmission Service Procurement	Common Reservation System for Market Interface Transmission ATC	Contract Tie Capacity - One Stop Shopping			All	PJM	MISO	Market Rule / Business Practice	No	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	No	2	
6	Transmission Service	Transmission Service Procurement	Common Western Interconnection Wide OASIS	Transmission Access	No transmission market one stop shopping available for the Western Interconnection - entities can't find needed information to efficiently conduct business on a preschedule or real-time basis. Solution: Common OASIS Site needed.		All	Non-RTO Market	Non-RTO Market/ISO Market	Market Rule/Business Practice	Yes - Various Transmission Providers	Steven Cobb - SRP	No		
89	Transmission Service	Transmission Service Procurement	Hour Ahead Transmission Service Market Standardization	Market Design - Day Ahead. Release of Unused Transmission Capacity after Close of DA Markets	How are boundary prices to be synchronized between RTO's if only one RTO has a hour ahead process? Is it necessary to align hour ahead markets? (Issue I.c.1)					Fundamental approach -- scheduling issues.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
33	Transmission Service	Transmission Service Procurement	Intra-Hour Transmission Service Procurement	Standard for Purchasing of Inter-Hour Transmission	The ability to purchase transmission after the top of the hour when the transmission service is predetermined as available in prior hour.		All	All	All	Market Rule / Business Practice	No	Tony Reed - Southern	No		
65	Transmission Service	Transmission Service Procurement	Long-Term Transmission Service for New Construction	Market Design - Prior to Day Ahead. Duration	To the extent that longer term transmission rights are needed for new construction, can agreement be reached to issue long term rights? (Issue I.a.6)					Fundamental approach -- financial hedging issue.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
67	Transmission Service	Transmission Service Procurement	Secondary Transmission Service Market Standardization	Market Design - Prior to Day Ahead. Primary Release Mechanism	There seems to be agreement here that a secondary market would be outside the RTO. If the resulting secondary market is not westwide, will coordination be needed? (Issue I.a.8)					Fundamental approach -- financial hedging issue.	SSG-WI, CMA Work Group	Syd Berwager - Bonneville PA	No		
112	Transmission Service	Transmission Service Procurement	Transmission Service for ICAP Market	Long-term Transmission Service Availability to Support ICAP Transactions - Firm transmission reservation requirements to establish "Deliverability" as a requirement to buy external ICAP results in an economic advantage for internal suppliers and a barrier to market entry for external suppliers.			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	
28	Transmission Service	Transmission Service Settlement	Consolidate Multiple Market Transmission Service Settlement Statements	Multiple transmission service charge invoicing	Being reviewed by PJM/MISO.		All	All	All	Market Rule / Business Practice	Yes	Linda Horn - WE Energies	No	3	
56	Transmission Service	Transmission Service Settlement	Consolidate Multiple Market Transmission Service Settlement Statements	Multiple transmission service charge invoicing	Companies that conduct business across Control Area borders are faced with receiving a TSC bill from each TO. A single charge should be provided to each transaction to the appropriate parties and revenues allocated to the TOs according to the appropriate usage formulas.		RTO Market to RTO Market	ISO New England	NY ISO		Northeast ISO	Joe Rossignoli - National Grid	G		

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
136	Congestion Management <u>Market Standards</u>	Standardize and Coordinate ATC Calculations and Postings <u>Market Standard Operating Time</u>	Reconcile ATC Calculations Between Physical and Financial Transmission Markets <u>NONE</u>	Firm Transmission Service on IMO/MISO <u>Inconsistent Market Event Timelines</u>	ATC postings between a physical reservation system and a financial reservation system. <u>There is a disconnect between the timing of bids and offers in the Ontario market and the releasing of firm transmission in MISO for which schedules have not been submitted for use as non-firm transmission.</u>		RTO Market to RTO Market	NPCC	ECAR	Market Rule / Business Practice	No	Barry Green - Ontario Power Gen.	No		
137	Market Standards	Market Standard Operating Time		Inconsistent Market Event Timelines	Timing issues between bid based markets (one example only - not knowing whether your bid has been accepted in "sink" market before having to commit in the "source" market).		RTO Market to RTO Market	IMO	NYISO	Market Rule	No	Barry Green - Ontario Power Gen.	No		

Subj: **Seams Catalogue**
Date: 12/5/2003 1:34:59 PM Central Standard Time
From: barry.green@opg.com
To: sccobb@srpnet.com, naesb@aol.com
CC: barry.green@opg.com

Sent from the Internet ([Details](#))

I apologize for not being as well prepared for today's call as I should have been. However, having missed at least 3 opportunities to comment during the call, I now find myself having difficulty with the categorization of one seam.

Nos. 136 and 137, which were the two issues that I identified have been allocated to 2 different categories and I think that is wrong. While the issues present themselves in slightly different ways since one is between the NYISO and Ontario IMO markets, while the other is between the Ontario IMO market and the MISO which is not yet a market, I would characterize them both as issues of "market standards".

I think your wording under the headings "category", "1st sub category" and "description of seam" for item 137 also work for 136.

As a comment for item 136 I would say:

"There is a disconnect between the timing of bids and offers in the Ontario market and the releasing of firm transmission in MISO for which schedules have not been submitted for use as non-firm transmission."

Sorry for being late on this. If you want to discuss it give me a call at 416-592-7883.

Barry

THIS MESSAGE IS ONLY INTENDED FOR THE USE OF THE INTENDED RECIPIENT(S) AND MAY CONTAIN INFORMATION THAT IS PRIVILEGED, PROPRIETARY AND/OR CONFIDENTIAL. If you are not the intended recipient, you are hereby notified that any review, retransmission, dissemination, distribution, copying, conversion to hard copy or other use of this communication is strictly prohibited. If you are not the intended recipient and have received this message in error, please notify me by return e-mail and delete this message from your system.
Ontario Power Generation Inc.

Barry Green
Ontario Power Generation, Inc.

Subj: **RE: UPDATED MATRIX**
Date: 12/5/2003 1:23:19 PM Central Standard Time
From: JOSEPH.ROSSIGNOLI@us.ngrid.com
To: Naesb7@aol.com, Naesb1@aol.com, sccobb@Srpnet.com
Sent from the Internet ([Details](#))

I apologize for missing the call.

A few concerns:

I guess I have a hard time viewing the imposition of a "sunset provision for implementation of Day 2 markets" in MISO as a standard. Are we talking about a timeline? A date? How would this be applied elsewhere? (#131)

The issue description "Long-term Transmission Service Availability to Support ICAP Transactions - Firm transmission reservation requirements to establish "Deliverability" as a requirement to buy external ICAP results in an economic advantage for internal suppliers and a barrier to market entry for external suppliers" strikes me as prejudicial as it relates to the any potential standards development. I guess what has been identified here is an intra-RTO "seam" relative to the purchase of internal and external ICAP. Might one remedy be to impose the same requirement on internal transactions rather than the opposite as suggested here? Isn't our mandate here limited to identifying seams (enough of a task), not solving them? (#112)

Joe

Subj: **RE: UPDATED MATRIX**
Date: 12/5/2003 1:47:20 PM Central Standard Time
From: JOSEPH.ROSSIGNOLI@us.ngrid.com
To: JOSEPH.ROSSIGNOLI@us.ngrid.com, Naesb7@aol.com,
Naesb1@aol.com, sccobb@Srpnet.com
CC: MARY.PARAVALOS@us.ngrid.com
File: **SeamsIssueCatalog12-5-03.xls** (91136 bytes) DL Time (TCP/IP): < 1 minute
Sent from the Internet ([Details](#))

To deal with my concern on #112, I have included here some additional language for the seams descriptor.

Joe

Joe Rossignoli
National Grid USA

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
112	Transmission Service	Transmission Service Procurement	Transmission Service for ICAP Market	<p>Long-term Transmission Service Availability to Support ICAP Transactions - Firm transmission reservation requirements to establish "Deliverability" as a requirement to buy external ICAP results in an economic advantage for internal suppliers and a barrier to market entry for external suppliers.</p> <p><u>Alternatively, the playing field may be leveled by imposing a deliverability requirement on internal ICAP transactions as well.</u></p>			Market to Market	PJM	ISO NE, NY ISO	Market Rule / Business Practice	In Northeast Power Markets Seams Action Plan	Jeff Mueller (PSEG), and Andy Rodriguez (PJM)	H	3	

Seams Issues Matrix

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Assoc/ Notes	Seam Interface Type	Region 1	Region 2	Seam Impediment Type	Currently Being Addressed ?	Submitter	Reference Papers	Priority	Resp Org
136	Congestion Management <u>Market Standards</u>	Standardize and Coordinate ATC Calculations and Postings <u>Market Standard Operating Time</u>	Reconcile ATC Calculations Between Physical and Financial Transmission Markets <u>NONE</u>	Firm Transmission Service on IMO/MISO <u>Inconsistent Market Event Timelines</u>	ATC postings between a physical reservation system and a financial reservation system. <u>There is a disconnect between the timing of bids and offers in the Ontario market and the releasing of firm transmission in MISO for which schedules have not been submitted for use as non-firm transmission.</u>		RTO Market to RTO Market	NPCC	ECAR	Market Rule / Business Practice	No	Barry Green - Ontario Power Gen.	No		
137	Market Standards	Market Standard Operating Time		Inconsistent Market Event Timelines	Timing issues between bid based markets (one example only - not knowing whether your bid has been accepted in "sink" market before having to commit in the "source" market).		RTO Market to RTO Market	IMO	NYISO	Market Rule	No	Barry Green - Ontario Power Gen.	No		



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NAESB Wholesale Electric Quadrant Electronic Scheduling Subcommittee

Procedure for adopting existing FERC Orders associated with OASIS Business Practice and Communication Protocols Standards

1. A Request for Standard and a Standard Recommendation are developed that are consistent with the FERC Order
2. The ESS votes to simultaneously
 - a. Submit the Request for Standard to NAESB and
 - b. Submit the Standard Recommendation to the EC
3. The Request for Standard goes immediately to Triage
 - a. NAESB will schedule a triage conference call
 - b. Triage will recommend assignment to the WEQ/ESS
 - c. The WEQ EC will ratify recommendation - by concall and/or notational vote
4. The Standard Recommendation is posted for due process comments
5. Simultaneously, the Request for Standard is Submitted to the JIC with recommendation to be remanded back to NAESB
6. At the end of the comment period, the ESS will review (probably via concall) the submitted comments and make a recommendation to the EC to
 - a. Approve the standard as originally recommendation
 - b. Suggest revisions to the Standard Recommendation based on the comments and recommend approval of the modified Standard Recommendation
 - c. Remand the standard back to the ESS for further development based on the comments
7. At the next scheduled EC meeting (or possibly by concall), the WEQ EC will act on the Standard Recommendation considering all ESS recommendations and industry comments
8. If approved by the EC, the standard will be put to member ratification

NORTH AMERICAN ENERGY STANDARDS BOARD
Executive Committee Meeting - WEQ, REQ, RGQ, WGQ Meeting Materials
December 9-11, 2003

TAB 9

WEQ 2004 Annual Plan



North American Energy Standards Board

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NORTH AMERICAN ENERGY STANDARDS BOARD

2004 WEQ Annual Plan

Approved by the Board of Directors December 4, 2003

Item Description	Completion ¹	Assignment
1 Develop business practices standards as needed to complement reliability standards		
(a) Develop business practice standards to support and complement NERC reliability standards, NERC policies and NERC standards authorization requests (SARs). Current NAESB activities underway to develop business practice standards that are supportive of this annual plan item are:		
<ul style="list-style-type: none">• Develop Inadvertent Interchange Payback Business Practices (Market Operations Subcommittee)• R03013 - Coordinate Interchange (Standards Review Subcommittee)• R03014 - Coordinate Operations (Standards Review Subcommittee)• R03017 -- Operate Within Limits (Standards Review Subcommittee)• Balance Resources and Demand• Facility Ratings		
(b) Develop business practice standards applicable to the transition period from NERC policies to NERC reliability standards.		
2 Develop and Maintain Business Practice and Communication Standards for OASIS and Electronic Scheduling		
(a) Develop and/or maintain <i>business practice standards</i> as needed for OASIS and electronic scheduling including determining which, if any, ESC/OSC and other related industry groups' business practices and standards should be adopted as NAESB standards. Specific items to address include:		
<ul style="list-style-type: none">(i) OASIS Phase IA<ul style="list-style-type: none">(a) Adoption of business practices per FERC Order 638(ii) OASIS Phase II per FERC ANOPR (Docket no. RM00-10-000) and subsequent orders<ul style="list-style-type: none">(a) Adoption/maintenance of ESC use cases(b) Adoption/maintenance of Functional Requirements Document(c) Develop and Maintain business practices to support and implement the ESC use cases		
(b) Develop and/or maintain <i>standard communication protocols</i> and cybersecurity requirements as needed, including related industry		

¹ Dates in the completion column are by end of the quarter for completion by the assigned committee. The dates do not necessarily mean that the standards are fully staffed so as to be implementable by the industry, and/or ratified by membership. If one item is completed earlier than planned, another item can begin earlier and possibly complete earlier than planned. There are no begin dates on the plan.



North American Energy Standards Board

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Home Page: www.naesb.org

NORTH AMERICAN ENERGY STANDARDS BOARD

2004 WEQ Annual Plan

Approved by the Board of Directors December 4, 2003

Item Description	Completion ¹	Assignment
standard communication protocols and cybersecurity requirements		
(i) OASIS Phase IA (a) Adoption of S&CP version 1.4		
(ii) OASIS Phase II per FERC ANOPR (Docket no. RM00-10-000) and subsequent orders (a) Development of S&CP document		
(iii) NERC PKI initiative		
3 Develop business practices standards to Improve the Current Operation of the Wholesale Electric Market		
(a) Develop business practice standards needed to complement or assist specific seams mitigation efforts initiated by or coordinated with the NERC, the IRC, RTOs or ISOs, or other regional entities.		
4 Determine the need for and develop, if necessary, standard(s) requests for electric or gas standards required to provide additional flexibility in generation scheduling (including gas nominations).		
PROVISIONAL ITEMS		
1 Develop standards and model business practices in accordance with FERC orders and rules issued in the SMD docket (RM01-12-000), or pursuant to Order Nos. 888 or 2000, or otherwise directed by the FERC.		
2 Respond to FERC inquiries pertaining to business practice standard development and keep FERC informed on the nature and effectiveness of coordination activities with other standards setting organizations.		
3 Develop business practice standards related to FERC's forthcoming generation interconnection orders (large and small generators), in Docket Nos. RM02-01-000 and RM02-12-000.		
4 FERC Reporting of Electricity Prices		
5 Develop business practice standards as requested by the regional and state advisory groups.		
6 Develop electric purchase and sales contract.		



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Appendix

Comments Accompanying the Action Items and Provisional Items For the 2004 Annual Plan Adopted by the Executive Committee - October 7, 2003

ACTION ITEMS:

- 1a The original 1(a) from the 2003 plan is implied and 1(b) and 1(c) have been rewritten as a part of this plan: 1(a) Apply NERC/NAESB MOU provisions in reviewing proposed reliability standards for their business practice implications, 1(b) Review existing NERC reliability policies and standards for their business practice implications, 1(c) Review each of the SARs in light of the NERC/NAESB MOU.
- 1b This is a new item that reflects the recent NERC decision to create Transition team. NAESB has been asked to join the Transition Team which is led by Gerry Cauley. NAESB members on the team are Charles Yeung, Rae McQuade and Michael Desselle.
- 2a The Information Technology Subcommittee has been formed and is currently reviewing existing lists of enhancements for OASIS 1A and OASIS 2. A NAESB Electronic Scheduling Subcommittee was created but is inactive awaiting input from the existing ESC industry group
- 2b The PKI request R03007 has been assigned to the NAESB WEQ to be addressed which is a portion of this annual plan item.
- This item also corresponds to the 2003 WEQ Annual Plan item 4(h) Review activities of NERC CIPAG in light of NERC-NAESB MOU regarding cyber security requirements for their business practice and system communication standards implications.
- 3a A seams catalog is under development now and will identify many of the items to be included under this action item. This item was originally numbered item 4 in the 2003 WEQ Annual Plan. Several items were deleted, and will be added back to the plan if they are requested through the comments or meetings on the plan and the requesters indicate a willingness to participate in the standards development effort or in the drafting effort. The items removed from the 2003 plan are: 4(a) Establish a standardized electric trading day; 4(b). Identify and develop business practices on the public dissemination of market information.
- Other items from the 2003 WEQ Annual Plan were reordered and renamed such as: 4(d) Develop business standards as necessary to resolve seams issues between ISOs and RTOs; 4(c) Establish standard business practices relating to: i) Definition and treatment of firm/nonfirm power; ii) Definition and treatment of firm/nonfirm transmission; iii) Provision of reserves for transactions across multiple control areas, 4(e) Develop standards for data requirements, data exchange and scheduling of day-ahead and real-time bilateral markets; and 4(h) Review activities of NERC CIPAG in light of NERC-NAESB MOU regarding cyber security requirements for their business practice and system communication standards implications.
- Some items on the 2003 WEQ Annual Plan were considered assumed in each of the action items, so they were not specifically highlighted as a separate action item, such as : 4(f) Examine business practices and definitions currently in use to determine applicability on a North American basis and 4(g) Catalogue, assess and prioritize existing "standards" that have significant business practice implications.
- 4 This is a new item, not in the 2003 plan. It was added at the August 5 Executive Committee meeting.



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Appendix

Comments Accompanying the Action Items and Provisional Items

For the 2004 Annual Plan Adopted by the Executive Committee - October 7, 2003

PROVISIONAL ITEMS:

- 1 These items (originally items 3 and 7 of the 2003 Annual Plan) were reclassified as provisional and will be acted upon as such FERC actions are taken.
- 4 This is a new item, not in the 2003 plan. It was added at the August 5 Executive Committee meeting.
- 5 This is a new item, not in the 2003 plan. It was added at the August 5 Executive Committee meeting.
- 6 There is industry interest, but there is neither consensus to move forward at this time nor may resources be available.

On August 5, several of the WEQ EC members discussed possibly preparing a request that would add an item to the 2004 annual plan to develop a master service agreement. The request was prepared but subsequently withdrawn by the submitter due to an expected lack of resources.

NORTH AMERICAN ENERGY STANDARDS BOARD
Executive Committee Meeting - WEQ, REQ, RGQ, WGQ Meeting Materials
December 9-11, 2003

TAB 10

WEQ Liaison Efforts



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UPDATE ON RELATED GROUPS

DECEMBER 4, 2003

Joint Interface Committee

The Joint Interface Committee met last on September 19 in Austin at ERCOTS Offices. The draft minutes of that meeting are attached. NAESB presented three requests for approval - all of which were assigned to NAESB for development. Those requests were: (1) Coordinate Interchange Business Practices, (2) Operate Within Limits Business Practices, and (3) PKI Business Practices. All of the requests are companion pieces to reliability standards development by NERC. NERC presented four certification requests, all of which were assigned back to NERC for reliability standards development. NERC will apprise NAESB should any business practices issues arise.

There was an October 17 conference call which was cancelled. A subsequent conference call for December 19 has been tentatively scheduled. We have no requests to present at this time to the JIC.

OASIS Standard Collaborative and Electronic Scheduling Collaborative

The business practices and communication protocol issues previously addressed by the OASIS Standards Collaborative and the Electronic Scheduling Collaborative have been assumed by the NAESB Information Technology Subcommittee chaired by Monroe Landrum and Alan Johnson, and the Electronic Scheduling Subcommittee chaired by Joel Dison, Andy Rodriguez and John Simonelli. The Information Technology Subcommittee is reviewing changes to OASIS as proposed for OASIS 1A and also undertaking the PKI efforts. The Electronic Scheduling Subcommittee will hold its first meeting on December 15-16 in Washington, D.C. It will review requests and recommendations to adopt the business practice standards and communication protocols outlined in Order 638 and Order 605.

Seams Efforts

The Seams subcommittee is finalizing the catalog to be released in December. A draft is included. We had participation from the ISOs and RTOs in developing this catalog. It will be forwarded to FERC, NERC, and the ISO-RTO Council once completed so that the organizations can determine which actions are to be taken.

Coordination with NERC

We continue to have excellent communication lines with NERC, from participating on both of their transition teams - one for transitioning existing policies to NERC reliability standards, and the other to address NERC post legislation issues. We are coordinating meetings with related drafting teams and share leadership in many of them. We participate in NERC's Market Committee, the group identified by NERC to coordinate any NERC-NAESB activities or issues.



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via email

TO: NAESB Managing Committee
FROM: Rae McQuade, NAESB Executive Director
Michael Desselle, NAESB Vice Chair of the Wholesale Electric Quadrant
RE: **Western United States Trip Report**
DATE: October 27, 2003

Dear NAESB Managing Committee,

Michael and I spent last week visiting several organizations and state agencies regarding NAESB activities, focusing on a high level overview of our organization, the accomplishments of 2003 and the plans for 2004. The goal of these meetings was to emphasize to the west that we could support their objectives with our standards, and that we strongly encouraged their participation - through active participation when they deemed it appropriate, or through monitoring.

We stressed that from the wholesale electric perspective, 2003 was primarily a year for building the structures to move forward on standards development, and that 2004 will be very active for standards development, which we are already beginning to see. We highlighted the ability for standards to reflect regional or operational differences, the restriction of our organization against advocacy of standards in front of regulatory bodies, and we noted that an easy way to monitor our organization is through the monthly update calls that were originally intended for state commission staff but has grown to be used by our own membership and others as a monitoring mechanism. From a retail perspective, we noted that both retail gas and retail electric quadrants were working together with the goal of creating joint model business practices - and that the creditworthiness standards and the billing and payments standards should be released within the first quarter of 2004.

Below is a listing of the meetings with specific observations made by the attendees:

Los Angeles Department of Water & Power

Tuesday, October 21, 2003

Met With: Dominick Rubalcava, President

Henry Martinez, Assistant General Manager for the Power Side

Observations:

- They strongly support the ability to reflect regional differences as the needs for LA may differ not only from other states and regions, but also from the rest of California.
- The voluntary nature of the standards is critical, as is the process used to develop those standards. The openness and the accreditation by ANSI of our organization as a SDO are crucial to the credibility of our work product.
- They are very interested in contracts and use the NAESB Gas Contract. They were under the impression that the EEI contract was a NAESB standard. We explained the activities that led to our organization not proceeding with the adoption of the EEI contract. They noted that they would look with interest if we determined to adopt the contract in the



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future. It should be noted that they brought this topic up without our mentioning it first.

- They are interested in the creditworthiness model business practices our organization recently developed. They think this would be a worthwhile effort on the wholesale electric side.
- They actively follow both the federal efforts on SMD and the state efforts on MD02. They have concerns that if mandated, these actions could negatively impact LA.
- They noted that some groups may be considering leaving the region and setting up their own RTO. They highlighted this as evidence that the marketplace is in flux and mandates may not be appropriate.
- They were very supportive of our efforts and organizational structure. They looked forward to monitoring our activities through the monthly update calls.

California Energy Commission

Wednesday, October 22, 2003

Met With: Chairman William Keese

Also attending were Al Garcia, Rick Buckingham, Mike Smith, Advisor to Commissioner James D. Boyd.

- Observations:
- They were very supportive of our organizational structure and activities. They noted that the ANSI accreditation gave our organization the credibility to draft standards.
 - They expect California utilities to become more active in their state and very interested in any standards or model business practices that support financial transactions and creditworthiness to aid them in prudence reviews.
 - They too brought up contracts before we noted such and were very interested in NAESB developing a bilateral contract. With the expected activity for California, they expect that such a document endorsed by NAESB would be a valuable tool.
 - They look forward to learning about the retail model business practices for creditworthiness and billing and payments at the winter NARUC meeting.
 - They have already developed and adopted extensive rules for the retail electric market that may be applicable to our efforts. As several California companies participate already, some of those rules may be reflected in our model business practices.
 - They will monitor our activities via the monthly update calls.



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California Public Utility Commission

Thursday, October 23, 2003

- Met With: Commission President Michael Peevey
- Also attending were Executive Director Bill Ahern, Director Barbara Hale, and Roosevelt Grant
- Observations:
- They supported our organization, its structure and a process that has been endorsed by ANSI.
 - Similar to the CEC, they are interested in the retail model business practices for creditworthiness.
 - They were also under the impression that the EEI contract was a NAESB product developed through NAESB's standards process. They would be interested in the bilateral contract being developed through NAESB. We noted why it is not on our 2004 annual plan due to lack of resources.
 - They were pleased to learn that they could ask us to develop business practices to support their needs.
 - They expect to monitor our activities through the monthly update meetings.

Western Area Power Administration

Friday, October 24, 2003

- Met With: Administrator Michael HacsKaylo
- Also attending were Robert Fullerton, Mark Fidrych, Jeff Ackerman, Mark Meyers.
- Observations:
- They supported our organization, its structure and a process that has been endorsed by ANSI.
 - They believe that the coordination between NERC and NAESB is working although perhaps not as shown in our "flower" charts. They expect the coordination to become more streamlined over the next year.
 - They hope that the Inadvertent Interchange Payback task force will bring some stability to an area that is causing them problems now – where the baseline data to be used to determine inadvertent interchange cannot be agreed upon by the parties.
 - They do not want a NAESB bilateral agreement, even if it takes the place of the EEI agreement. Right now they use the WSPP agreement and expect that if NAESB endorses and replaces the EEI contract, the NAESB contract will have more credibility and outreach to potential users of the agreement – thus increasing their level of support to address both the WSPP agreement and the NAESB one as well. Right now, neither they nor their customers use the EEI contract. They would not support any action that would give credibility to another agreement.



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- They do already participate via Mark Fidrych and monitor our other activities via the monthly update calls.

Best Regards,

Rae