TAB 6

WEQ Subcommittee Updates

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
Modified by the WEQ Executive Committee – December 9, 2004

	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:		Standards Review Subcommittee (SRS)[2]
	i. Develop Inadvertent Interchange Payback Business Practices		BPS (IIPTF)
	ii. R03013 – Coordinate Interchange		SRS/ESS
	iii. R03014 – Coordinate Operations		SRS
	iv. R03017 -- Operate Within Limits		SRS
	v. Balance Resources and Demand		SRS
	vi. Facility Ratings		SRS
	(b) Develop business practice standards applicable to the transition period from NERC policies to NERC reliability standards.		SRS/Various[3]
2	**Develop and Maintain Business Practice and Communication Standards for OASIS and Electronic Scheduling**		
	(a) Develop and/or maintain *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 adopted as NAESB standards. Specific items to address include:		Electronic Scheduling Subcommittee (ESS)
	i. OASIS Phase IA (a) Adoption of business practices per FERC Order 638		ESS
	ii. OASIS Phase II per FERC ANOPR (Docket no. RM00-10-000) and subsequent orders 1. Adoption/maintenance of ESC use cases		ESS

[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 Standards Review Subcommittee scopes, identifies and defines the standards development work to be done to suppoer and complement NERC policies, SARs and NERC reliability standards. Once completed, the request, initial review document, scoping document and other work papers are transferred to the appropriate standards development subcommittee.

[3] The North American Electric Reliability Council Transition Team is responsible for establishing a plan to convert existing NERC policies to NERC reliability standards. Co-commitant with that conversion, NAESB will develop corresponding NAESB business practices. Michael Desselle, Rae McQuade and Charles Yeung are representatives of NAESB on the NERC Transition Team.

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	Item Description	Completion[1]	Assignment
	2. Adoption/maintenance of Functional Requirements Document		ITS
	3. Develop and Maintain business practices to support and implement the ESC use cases		ESS
	(b) Develop and/or maintain *standard communication protocols* and cybersecurity requirements as needed, including related industry standard communication protocols and cybersecurity requirements		Information Technology Subcommittee (ITS)
	(i) OASIS Phase IA Adoption of S&CP version 1.4		
	(ii) OASIS Phase II per FERC ANOPR (Docket no. RM00-10-000) and subsequent orders 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.		Seams/Various[4]
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).**		Gas Electric Coordination Task Force[5]

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

[4] The Seams Subcommittee scopes, identifies and defines the standards development work to be done related to the seams catalog. After seams catalog items are assigned to NAESB by the Joint Interface Committee, and the Seams Sucommittee completes its review and analysis, the request, initial review document, scoping document and other work papers are transferred to the appropriate standards development subcommittee.

[5] The Gas Electric Coordination Subcommittee is an ad hoc subcommittee comprised of participation by all four quadrants of NAESB to address the issues outlined in request number R03031, submitted by TVA and amended on November 20, 2003.

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	Item Description	Completion[1]	Assignment
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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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.

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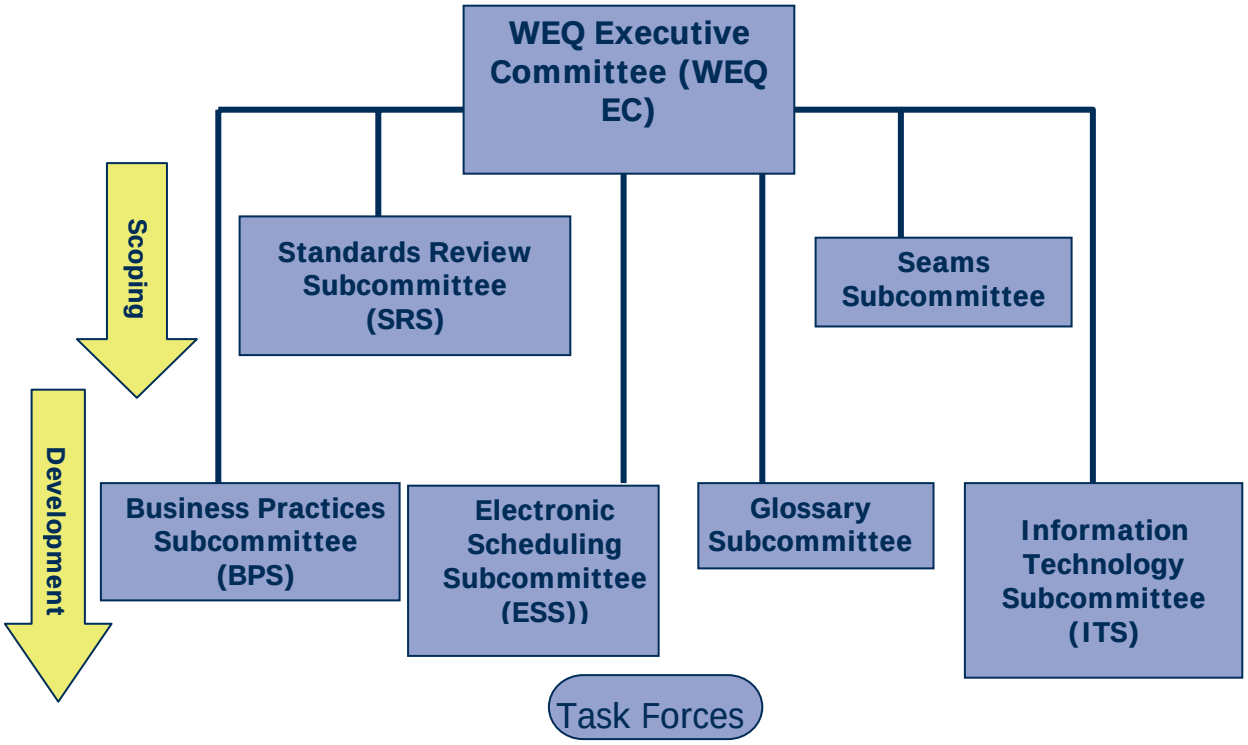
NAESB Wholesale Electric Quadrant Committee Structure



Subcommittee Leadership is:

Executive Committee: Lou Oberski (WEQ EC Chair) and Steve Cobb (WEQ EC Vice Chair)

Standards Review Subcommittee: Charles Yeung and Raj Rana
Seams Subcommittee: Steve Cobb and Joe Rossignoli
Business Practices Subcommittee: Bob Goss
Electronic Scheduling Subcommittee: Joel Dison, Andy Rodriguez and John Simonelli
Glossary Subcommittee: Tony Reed and Sherri Monteith
Information Technology Subcommittee: Monroe Landrum and Alan Johnson

IIPTF Documents

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TO: NAESB Wholesale Electric Quadrant, Posting for Interested Industry Participants

FROM: Todd Oncken, Deputy Director

RE: NAESB WEQ Inadvertent Interchange Payback Task Force Draft Minutes – January 22-23, 2004

DATE: January 29, 2004

Wholesale Electric Quadrant
Inadvertent Interchange Payback Task Force
January 22-23, 2004; Dallas, TX
Draft Minutes

1. Welcome

Mr. Terelmes opened the meeting. Mr. Oncken gave the antitrust advice. Participants introduced themselves. Mr. Terelmes reviewed the agenda and the agenda was adopted by consent. Mr. Terelmes reviewed the motions previously adopted by the IIPTF, as well as the motions that were currently tabled.

Mr. Terelmes reviewed his notes on high level issues contained in the NERC JIITF whitepaper. Mr. Terelmes recognized that the JIITF whitepaper should be viewed as a resource that could be useful for direction and reference. Mr. Terelmes suggested the proposal to link the energy and frequency components of Inadvertent Interchange runs counter to the whitepaper. Mr. Terelmes referenced several sections of the document that support this assertion. Mr. Illian noted that a limiting factor of separating all of the components of Inadvertent Interchange was that in some markets the transmission and energy prices are bundled.

Mr. Terelmes reviewed a discussion held with Raymond Vice, chair of NERC's Balance Resource and Demand standards drafting team, at a recent NAESB Standards Review Subcommittee (SRS) meeting. Mr. Terelmes said Mr. Vice explained that the BRD drafting team is looking at a frequency standard composed of three (currently undetermined) frequency bandwidths – trigger, frequency abnormal, and relay – that correlate to the system's instability. Mr. Terelmes recounted that Mr. Vice was very clear that the NERC BRD drafting team did not want a violation of their frequency standard to result in a business practice or economic issue, because frequency should remain a reliability issue. Mr. Blohm commented that the bandwidth benchmarks listed above were for Reliability Authority (RA) intervention in extreme cases.

2. Al DiCaprio presentation

Mr. DiCaprio's presentation was a followup to his comments during the December IIPTF meeting. Mr. DiCaprio stated his presentation was based on the available data from the WECC, but encouraged participants to focus on the concept – not the data. Mr. DiCaprio stated that the data demonstrates the concept of paying for Inadvertent Interchange at the highest available price with some bandwidth where financial or physical settlement would not occur. Mr. DiCaprio asserted this proposal adequately maintains the separation of business and reliability (frequency) issues. Additionally, Mr. DiCaprio suggested this method was much less complicated than other options considered and would create a natural bias regardless of congestion. Under Mr. DiCaprio's proposal, settlement would equal (schedule – actual) * price. Mr. DiCaprio encouraged the IIPTF to work with the Coordinate Interchange Business Practices

task force to better understand the meaning and parameters of a schedule, noting the obvious impacts of that understanding on the definition of Inadvertent Interchange.

Mr. DiCaprio noted that there were data integrity issues, even though it has already been established that the settlement mechanism would value the data provided by NERC, because the numbers never settle to zero. He stated that reducing variations to financial settlement will only enhance the need for reconciled data. He went on to identify a critical issue that the task force has been struggling with for some time – should all Inadvertent Interchange be settled, or should only flows outside of an acceptable range be settled.

Participants offered comments on Mr. DiCaprio's proposal. Mr. Terelmes said a deadband where a frequency adder is not charged would result in a price that is equal to the market cost and will not provide incentives. Mr. Blohm suggested that selecting the highest price on the interconnection would override the transmission component as reflected in the price differences and congestion. Mr. Blohm expressed concern about instances of extreme pricing. Mr. Illian stated this method would be a single-price market alternative and questioned whether the proposal helped move the group forward. Further, Mr. Illian said participants think a deadband could simplify the problem, but simpler is not defined. He noted that under this scenario there would be two settlements – one inside and one outside the deadband and asserted two settlements was more complex than one settlement. Mr. Power commented that a mechanism that would allow for a small variance without penalty was essential, in part because of the time required for an operator to react. Mr. Power suggested that a deadband could help alleviate data integrity concerns and the potential need for metering standards. Mr. Goins noted that settling everything, without a deadband, would produce a situation where every hour, every day would have to be settled, and that would be a huge burden. Mr. Henry expressed concern that a deadband for market optimization was being considered. Further, he cautioned that rules that would encourage people to crowd the system or jeopardize reliability would be unacceptable. He went on to state that deadbands have worked and provided a simpler solution in many instances.

Mr. DiCaprio responded to the discussion of his presentation. He clarified the bandwidth contained within his presentation was a no-payment (physical or financial) zone. Additionally, he suggested inside the bandwidth would be a non-accumulation zone. Mr. DiCaprio said cost disclosure should not be an issue, because there is only one highest number, and that would be something determined after the fact. Additionally, he noted the price would be disclosed to the Control Areas (since they are the parties with Inadvertent Interchange) and they are covered by confidentiality agreements anyway. It was suggested that excessive over generation would be kept in check by lack of knowledge of frequency.

Mr. Terelmes suggested that clearly defined terms would help to move the task force forward. It was noted that deadband is a common term in the industry, but there were different interpretations of its meaning. To reach commonality, it was agreed to discuss bandwidths where different kinds of settlement could occur. It was noted that a bandwidth was not necessarily balanced or equal around center. After extensive debate, the following definition was offered: Mr. DiCaprio moved, seconded by Mr. Power, to define 'Frequency Bandwidth' as follows – a range of deviation around the interconnection scheduled frequency. Mr. Cox provided the following friendly amendment to the motion, which was adopted by Mr. DiCaprio and Mr. Power: define 'Frequency Bandwidth' as follows – a range of deviation around 60 Hz or the interconnection scheduled frequency. During discussion of the motion, Mr. Terelmes clarified that this definition did not conflict with NERC definitions, but would serve as a

method for the task force to move forward from an economic perspective. The amended motion passed with Mr. Henry opposed.

3. Tony Reed Presentation

Mr. Reed stated that his proposal includes a bandwidth and a single price model. He cautioned that the exact amounts of the adder and bandwidth were not a proposal, but instead were offered for discussion purposes only. Mr. Reed noted that several issues remain unresolved. Mr. Reed stated that all Inadvertent Interchange costs someone money to provide, therefore some compensation for all Inadvertent Interchange is needed. Mr. Reed explained that under his proposal, a premium or discount would be included in the settlement against the highest or lowest price for the inappropriate actor for actions outside the bandwidth. The settlement would be done for MW based on Hz. It was noted the issue of regional pricing is not addressed in this presentation, but his thought was that regional pricing might be more appropriate. Mr. Reed noted that he does not support settling every deviation financially.

Participants commented on Mr. Reed's proposal. Mr. Terelmes stated the following concerns with this approach. First, he said breaking down the prices could create a seam and lack of balance. Second, he said that if the band was too wide there could be a situation where people could game the system. It was also noted that there should be better definition of the proposed adder. Mr. Blohm stated that the issue of accumulation was very important. Mr. Illian commented that a single price model tends to bypass the transmission congestion issue. However, he did support further investigation of the regional location price idea. Additionally, Mr. Illian suggested that the task force investigate: 1) whether energy price is the correct component to use against the adder; and 2) the correlation between the price and frequency.

Mr. DiCaprio noted the parallels between this method and his proposal. Mr. DiCaprio said this was a pragmatic approach that focuses on Inadvertent Interchange, not frequency. Further, he favored the regional approach for determining the highest price, noting that it would likely be more accepted by the industry.

Participants discussed the bandwidth concepts further. Mr. Terelmes noted it was becoming evident that bandwidth and Inadvertent accumulation are linked, since a bandwidth would result in some accumulation. Participants did not feel accumulation was within the scope of the task force. Since there will likely be accumulation, Mr. Illian questioned whether the settlement method should have a rule associated with timing of payback. Mr. DiCaprio noted that settling Inadvertent does not address time error accumulations, even though they are related to Inadvertent.

Mr. Illian moved, seconded by Mr. DiCaprio that the task force commit to having a bandwidth that requires financial settlement outside and no settlement, physical settlement or financial settlement within the bandwidth and work towards a resolution of the internal settlement. Mr. Illian suggested this motion would lay the foundation for future discussions. Mr. Terelmes noted the effect of this motion was that settlement outside the bandwidth was financial and not payback in kind. Mr. Illian and Mr. DiCaprio amended the motion to read as follows: Settlement outside a frequency bandwidth would be financial.

Participants discussed whether the financial settlement would be for energy and/or frequency. It was noted that the motion leaves that issue not determined. After discussion on the motion, the motion passed with 5 in favor, 2 opposed (Mr. DiCaprio and Mr. Henry) and the rest abstaining.

Mr. Power moved, seconded by Mr. Henry, that the financial settlement outside a bandwidth would be limited to inadvertent energy and not include a frequency control component. During discussion, Mr. Blohm asked whether the motion would mean that settlement would not address frequency, or it would rule out frequency. Mr. Power replied the motion would mean that settlement would not include a frequency control component. Mr. Cox noted the motion implied that frequency could be settled for inside the bandwidth. Mr. Reed noted the adder in his proposal would not be affected by the motion because it was not dependent on the magnitude of the error. The motion was tabled.

Day one adjourned at 3:40 p.m. Central.

4. Welcome - Day Two

Mr. Terelmes opened the meeting. Mr. Oncken gave the antitrust advice. Participants were introduced.

Mr. Terelmes read the following motion submitted by Mr. DiCaprio: Strike Mr. Illian's response to the requested methodology on the basis that Mr. Illian's response was unprofessional. Mr. Terelmes reviewed the document that was the subject of the motion. Mr. Vandervort seconded the motion. Mr. Illian responded that he would be willing to modify some conclusions stated in the document. Due to Mr. DiCaprio's absence, it was agreed that the document would be removed from the NAESB website and Mr. Illian would be free to resubmit a replacement document that was more appropriate. There was no further action taken on the motion.

Mr. Terelmes noted that it is the general desire of NAESB that the task forces operate in a causal manner. However, he stated concerns have been raised within the task force regarding the ability of all participants to be heard with the full attention of the task force. Accordingly, he outlined the following procedures for moving forward: 1) participants should address their comments to the chair and limit their comments to a reasonable time (2 to 5 minutes); 2) participants will be recognized by the chair before they speak; 3) interruptions and inappropriate comments will not be tolerated; 4) implementation will occur through a warning system such that after the second warning the offending party will be removed from the room for the duration of discussion, after the third warning the offending party will be removed from the room for the duration of the meeting; and 5) points of order will be recognized. The above procedures are consistent with Roberts Rules of Order.

5. M. Lively Motions

Mr. Lively submitted 10 motions prior to the meeting, each of which will be addressed separately. Mr. Lively explained that his motions track the format of historical NAESB standards. Mr. Lively reviewed the workpaper. Mr. Lively asserted this is a conversion of the concepts the task force has discussed into a format typically used in NAESB. This sparked an extended discussion about the nature of NAESB standards, and the expectations of the WEQ Executive Committee. During the discussion concerns of coherence were raised with the multiple independent standards model since removing one piece of a package could have an extreme effect on the whole. Mr. Oncken clarified the role of the Executive Committee in standards development. Mr. Terelmes noted that using the historical NAESB paradigm would create an opportunity to produce results for the Executive Committee's consideration, even if all issues could not be solved. Mr. Vandervort commented that his assumption was that the standards would be formatted like NERC standards. While there was no formal resolution, it was agreed to consider Mr. Lively's motions and evaluate whether the previous motions could be converted into a similar format should the need arise.

Mr. Lively moved, seconded by Mr. Vandervort, that parties may handle inadvertent interchange on a bilateral basis. (Lively motion 1) Mr. Lively asserted that parties should be able to interact with their neighbors as they see fit. Mr. Illian asserted that this motion was out of order in light of the previously passed motion stating that Inadvertent Interchange is between a party and the grid. Mr. Lively clarified that under the motion parties could establish agreements to settle between themselves, which was different than their interaction with the grid as a whole. There was not agreement that was an appropriate result. Participants voted on Mr. Illian's objection. The vote carried and the motion was found in conflict. Mr. Vandervort amended the motion to read as follows: Parties may handle inadvertent interchange settlement on a bilateral basis. Mr. Lively accepted the amendment. Parties did not find the amended motion in conflict with the previous motions. The amended motion failed with 2 in favor (Mr. Lively and Mr. Davis) and 6 opposed.

Mr. Lively substituted Mr. Power's tabled motion for his motion 5, as follows: the financial settlement outside a bandwidth would be limited to inadvertent energy and not include a frequency control component. Mr. Goins seconded the motion. Mr. Power opened discussion noting that the only thing he was trying to limit was a frequency control component being used as a price adder. There was extended discussion on the motion. Mr. Illian stated that an adder that was reactive to high frequency would in fact be a frequency control component. He went further to say if an adder does not react negatively, then it sends the wrong price signal. Mr. Goins reiterated that the frequency control component would only be used to determine the bandwidth. Mr. Blohm suggested that this motion would be in conflict with Mr. Lively's proposed motion 7. Mr. Blohm was excused from discussion pursuant to the procedures outlined above.

Mr. Illian asserted that an adder not related to frequency would result in something price perverse, and if the adder is removed the result is a situation where there is nothing different between scheduled and unscheduled energy. Mr. Illian objected to both alternatives. Mr. Illian stated the task force has a basic misunderstanding of frequency control

On Mr. Terelmes's request, the motion was amended to read as follows: The financial settlement outside a bandwidth would be limited to inadvertent energy and not include a frequency control component, except that direction of frequency could be used to indicate the good or bad nature of the Inadvertent.

Mr. Illian asserted this motion is a blatant attempt to bypass a previously adopted motion – a result he does not find acceptable. On further consideration, Mr. Lively said his current understanding of the motion was that the price shall not in any way reflect the frequency that exists on the system at the time of the occurrence, except as a test for the nature of the Inadvertent Interchange. Mr. Lively disagreed with that concept and moved, seconded by Mr. Vandervort to table the motion. The motion to table failed.

After discussion of the motion was completed, Mr. Blohm was invited back to vote on the motion. Prior to the vote, Mr. Blohm stated that the motion violated the antitrust rules because the intent and content of antitrust is against price fixing. Mr. Blohm defined price fixing as a non-economic basis for a price. Mr. Oncken interrupted discussion of the motion and the motion was tabled in light of the antitrust violation assertion by Mr. Blohm.

6. Continued Discussion and motions regarding Inadvertent energy and frequency deviation

See discussion above.

7. Adjourn

The meeting adjourned at noon Central.

8. Meeting Attendees

Name	Company	Day One	Day Two
Bill Bateman	Georgia System Operations	In Person	In Person
Terry Bilke	MISO	Phone	Phone
Robert Blohm	Consulting Economist	In Person	In Person
Keith Comeaux	Cleco Power	Phone	
Phil Cox	AEP	In Person	In Person
Ed Davis	Entergy	Phone	Phone
Al DiCaprio	PJM	In Person	In Person
Mark Fidrych	WAPA	Phone	
Larry Goins	Tennessee Valley Authority	In Person	In Person
Nick Henry	SMUD	Phone	Phone
Howard Illian	Energy Mark	In Person	In Person
Mark Lively	Util. Econ. Eng.	In Person	In Person
Lou Oberski	Dominion	Phone	Phone
Todd Oncken	NAESB	In Person	In Person
John Power	MISO	In Person	In Person
Tony Reed	Southern Company	In Person	In Person
Steve Terelmes	Ameren	In Person	In Person
Dean Ulch	Southern Company	Phone	Phone
Tom Vandervort	NERC		In Person

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via email and posting

TO: NAESB WEQ Inadvertent Interchange Payback Practice Task Force

FROM: Todd Oncken, NAESB Deputy Director

RE: IIPTF Substantive Motions

DATE: January 20, 2004

The following is a compilation of successful substantive motions passed at the IIPTF since September 2004.

September 15-16, 2003
Mr. Cox moved, seconded by Mr. Goins, as follows: The IIPTF recognizes the discovery phase is largely complete and will begin the drafting phase. Any new discovery material must be approved by this task force through a formal motion. After limited discussion the motion passed with Mr. Illian, Mr. Blohm and Mr. Lively abstaining.

October 6, 2003
Moved by Mr. Terelmes and seconded by Mr. Goins. "The settlement of inadvertent as the IIPTF was tasked will be broken down into four components. 1) Inadvertent energy hourly measurement 2) Frequency hourly measurement 3) Hourly valuation for inadvertent energy 4) Valuation for contribution to frequency deviation. Valuations can be considered positive, negative or zero, and this does not preclude physical payback. The motion passed.

Moved by Mr. Terelmes and seconded by Mr. Illian. "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. The motion passed.

Moved by Mr. Terelmes and seconded by Mr. Blohm. "NERC has agreed to provide inadvertent energy and frequency deviation measurements with hourly granularity. Although payback of inadvertent energy and contribution to frequency deviation shall be performed for each hour, reporting of such hourly information to be used for settlement purposes shall occur at such time intervals as deemed feasible by NERC. The IIPTF will accept the limitation of monthly measurement reporting frequency until such time that technology and NERC allow this data to be reported more frequently." The motion passed.

Moved by Mr. Terelmes and seconded by Mr. Oberski. "In an effort to arrive at a better method for the settlement of inadvertent, the IIPTF will consider only two basic methodologies. 1) Financial settlement for inadvertent 2) Physical settlement of inadvertent. The fact that inadvertent has at least two components, also allows for a combination of the above methodologies. The motion passed.

Moved by Mr. Blohm and seconded by Mr. Illian. "The IIPTF defines a Balancing Authority's Inadvertent Interchange as its Inadvertent Interchange 'with the interconnection.'" The motion passed.

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December 11, 2003

Mr. Illian moved, seconded by Mr. Reed, that "the IIPTF consider the settlement of reactive power to be out of scope with our charge and no longer be included as an issue in our discussion." Mr. Lively stated this issue should be handled consistently with the handling of inadvertent interchange. Mr. Reed agreed that at some point reactive power should be addressed but at this time the group should move forward by focusing on inadvertent interchange. Upon a procedural vote the motion passed.

Mr. Illian moved, seconded by Mr. Cox, "that the discussion of Time Error is consistent with the issue of Frequency." Upon a procedural vote the motion passed absent objection.

Mr. Illian moved, seconded by Mr. Blohm that "any methodology unable to represent negative energy prices is incompatible with a reasonable inadvertent settlement methodology, and therefore should be eliminated from discussion." Upon a procedural vote the motion passed.

Mr. Henry moved, seconded by Mr. Goins that "the IIPTF write a standard that may include an allowance for each interconnection to develop a method that settles inadvertent and corrects frequency error to operate in a manner to compensate for inadvertent in an interconnection's selected time intervals." Upon a procedural vote, the motion passed.

E-Tag and TSIN Reports

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. 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 is suggested that the IT and ESS work jointly on this issue as both a technical and business practices effort in specification in OASIS 1A.

The statement above "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**" is incorrect. The primary provider must track assignment numbers, scheduling rights, and manage ATC.**

Follow the money. Resale of transmission service does not relieve the primary customer of the financial obligation to the primary provider. As such, the primary customer must make the request for transmission service redirect to the primary provider on behalf of the secondary customer.

Reassignment of transmission service transfers the financial obligation with the primary provider from the primary customer to the secondary customer. At that point, the secondary customer must work with the primary provider for redirects.

All redirect requests must be placed in the appropriate queue and appropriate priority.

OATI/PRS: MIC and the ESC both agreed with definition of two types of secondary market transactions as stated above: 1) resale for transfer of scheduling rights only and 2) reassignment for complete transfer of financial and all other Ts&Cs under the tariff. Agree with the above statements that business practice standards should be drafted in support of these two types of secondary market transactions. And, explicitly limit the rights under "resale" to transfer of scheduling rights only, Redirection would require full reassignment under the tariff with secondary market customer then being required to deal directly with the TP.

Another issue that should be discussed in the context of "resale" is what scheduling rights are conveyed to the third party? Some TPs interpreted "resale" to allow the TC to resell the capacity as any valid product of equal or lower priority. One might argue however, that if the third party purchases one hour from a TC on a monthly non-firm reservation, why wouldn't that third party have monthly non-firm priority with respect to scheduling. If the original TC retained the reservation they would have such priority in event of a TLR. So, the practice might be that the "resale" reservations should carry the same transmission service/priority of the original (or lowest of the group if TC aggregated capacity from many reservations?), but not be bound by any of the service increment requirements/restrictions.

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.

Service redirected on a firm basis decrements firm rights on the parent reservation. Recalls/curtailments on the child reservation path do not entitle the rights holder to firm capacity on the parent path without going through the redirect process. The rights holder may request redirect back to the parent path (or any other path of that provider) on a firm or non-firm basis. Of course their position and priority in the queue for this second (or third, etc.) redirect is treated or positioned as any new request coming in.

Service redirected on a non-firm basis does not decrement firm rights on the parent reservation (although total scheduling limits are capped at the parent reservation rights). A recall on the child path will not prevent the exercise of full firm scheduling rights on the parent path or prevent the request for a redirect on to another path.

OATI/PRS: Agree.

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 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).

Order 605 did address in a general sense the users' impact to OASIS, but not this specific item (multiple requests). FERC did ask the How Working Group and NERC's MIC for input (we should find their respective responses) and review what the MIPS did.

My read of 605 is providers need properly sized OASIS's and customer need to give fair warning of expected heavy use. The Order does not address a provider's human resource limitations in processing large volumes of requests.

OATI/PRS: Believe there is some confusion based on above response. The issue was addressed by the MIC and a proposal filed with FERC that was ultimately denied. The problem could be termed "queue hoarding". Because of the 638 customer confirmation time limits, if a TP processes reservations in strict first-in-first-out priority, a TC could conceivable submit multiple like reservations in close succession. When there is limited availability, the TP would accept the first queued reservation, but not proceed with acceptances of other queued requests until the TC confirmation time limit expired. At that time the acceptance is retracted (or withdrawn by the TC) and accept the next reservation in line, which is from the

same TC. The TC has tied up the little remaining capacity with apparently little intention of confirming a reservation. Several solutions have been suggested; accept all and first to confirm wins, etc. ESS should review the MIC filing that was denied. If not in the MIC filing, suggest that TPs have the right to "purge" their reservation queue of all reservations from the same TC, on the same Path, with the same start time, if that TC fails to exercise the TPs acceptance of the earliest queued request (either TC withdraws or confirmation time limit expires).

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.

We should act as a "what" group on this issue. The list of what items shown above should be supported in the S&CP for network service and native load. I would add to the list above, the required request submittal for ATC to accommodate secondary network resources (an OASIS submittal for transmission services to support spot and short-term network purchase/resources).

OATI/PRS: Agree that use of non-designated resources on a secondary basis should be supported by a standard business practice and standard mechanism on OASIS to make such arrangements. These standards could be based on submission of scheduling information. Many TPs allow use of non-firm secondary via tags with no OASIS reservation. Due to the priority NITS use of non-designated resources might be more restrictive. Will need timing rules; max duration and lead times for such requests; whether these are a special form of REDIRECT; etc.

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.

FERC started to address naming in Order 638, section 6. Anything developed here would most likely be added to section 6. Perhaps a standard such as we use in the western interconnection - the facility operator determines name (in many cases that is the host control area) and all TPs sharing that point must adopt the name. The standard could also require each NERC region make sure point naming is cleared-up (it could be argued this is also a reliability issue due to potential confusion on facility naming)

OATI/PRS: Agree that the western naming convention greatly facilitated the determination of "adjacencies" between various TPs and allowed for identification of contract paths between entities. This should be promoted throughout all interconnections and supported by the TSIN (aka NERC) Registry.

DONALD M. BENJAMIN
Vice President

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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

January 5, 2004

Ms. Rae McQuade
Executive Director
North American Energy Standards Board
1301 Fannin, Suite 2350
Houston, Texas 77002

Dear Rae:

Maintaining the Transmission Service Information Network

As NERC and NAESB continue working together on electronic scheduling and OASIS protocols, the issue of who will continue to maintain the Transmission Service Information Network (TSIN) occasionally arises. To allay any concerns that NERC was expecting NAESB to take over this responsibility, we want to assure NAESB that NERC remains committed to maintaining TSIN.

A bit of history is in order…

History of TSIN. TSIN resulted from FERC Order 889, which established OASIS. The OASIS "How" Working Group wrote the Standards and Communications Protocols (S&CP) document defining the technical requirements of OASIS. The S&CP mandated a central registry of OASIS participants and service offerings, and, in 1996, NERC offered to create and house this registry. The S&CP does not specifically mention NERC, but it does reference http://www.tsin.com as the official registry site. NERC owns the TSIN domain.

NERC has since expanded the registry to include entities involved in electronic tagging. (In fact, electronic tagging is more dependent on the TSIN registry than OASIS applications.) We are also redesigning the TSIN registry to support the needs of the e-MARC PKI, better integrate with NERC's Names and Address Database (NADS), and improve the user interface "look and feel."

NERC support of TSIN. The usefulness of the TSIN database has certainly expanded beyond its original purpose, and we expect that NERC will continue to support this database for our purposes whether or not the OASIS or tagging requirements continued to exist.

We do not want to preclude other arrangements for supporting TSIN (or its possible alternatives) in the future; however, any changes to the current arrangement would only be made after discussion and consultation among all the relevant stakeholders.

Sincerely,

Donald M Benjamin

All,

At the Market Committee's January 14, 2004 meeting, the committee agreed to the following:

E-Tag Enhancement Survey — *The MC reviewed the results of the E-Tag Enhancement Survey and recommended that the Interchange Subcommittee and Transaction Information Systems Working Group work with the NAESB Electronic Scheduling Subcommittee (ESS) to determine feasibility and cost of proceeding with proposed changes to the E-Tag system.*

The Interchange Subcommittee is scheduled to meet on February 2-4 and will continue to work on the survey at that time. Would the ESS provide comments on the coordination effort with the IS, and the most efficient way to continue addressing the survey, for this meeting?

The Market Committee requested that the ESS and IS work on "interchange tools" to address the Coordinate Interchange Standard and Coordinate Interchange business practices:

Reliability Standards — *The MC provided comments on the Coordinate Interchange Standard currently under development. The MC asked the NERC standard drafting team and the NAESB business practice drafting team to consider how NERC Interchange Authority certification would be reconciled with interchange tools that would be required by NAESB business practices and the NAESB Electronic Scheduling Subcommittee.*

Therefore, in conjunction with the item on the E-Tag Survey, will be an agenda item on "tools" as related to:

- Policy 3 - Tagging
- The Coordinate Interchange Standard (tools for reliability)
- Coordinate Interchange business practices Request for Standards (tools for the market)

This discussion should address tools for the interim or transition period (the period of operations under the current Control Area paradigm) and the period for operating under the new reliability standards, envisioned to begin at the end of 2006.

I have attached a letter from Don Benjamin to Rae McQuade that discusses the Registry – entitled "Maintaining the Transmission Service Information Network." This letter demonstrates the cooperation between NERC and NAESB on tools currently being used by the industry. The ESS and IS should discuss, and inform the industry, how E-Tagging will be coordinated and facilitated during the transition to OASIS II and electronic scheduling.

The Operating Committee, during the discussion of the CI Standard and CI business practices, asked, "How would the implementation of NERC and NAESB standards be coordinated?" "How will differences, such as ramping or timing requirements, between

reliability standards and business standards be reconciled?" The Market Committee also discussed items related to NERC – NAESB coordination, including:

NERC / NAESB Coordination — *As an ongoing part of the NERC effort to coordinate with NAESB, the MC dedicated part of its meeting to a review of NAESB activities. NAESB representatives provided the MC with an update of their seams catalog project, which is scheduled for presentation to the Joint Interface Committee (JIC) in February. The MC will be working with the Operating and Planning Committees to provide NERC JIC representatives with a reliability perspective of the 137 items contained in the seams catalog.*

The MC was also provided with a review of the NAESB ESS efforts related to OASIS, OASIS 1A, and OASIS II business practices and technical standards development.

The NAESB Leadership Group will be meeting jointly with the MC during part of the MC's March 2004 meeting in Nashville.

The Interchange Subcommittee will review and provide input into those items in the NAESB Seams Catalog related to Policy 3, Tagging, and the coordination of interchange.

Gordon L. Scott
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February 3, 2004

Via email

Dear NERC Interchange Subcommittee:

The NAESB WEQ Electronic Scheduling (ESS) and Information Technology (ITS) Subcommittees would like to respond to the January 19th letter from Gordon Scott regarding the coordination of ETAG efforts with the NAESB WEQ ESS and ITS. As has been demonstrated by efforts at the JIC as well as ongoing efforts at various subcommittee and drafting team levels, NAESB remains committed to working with both NERC and the ISO-RTO Council to ensure that the critical issues facing the industry are properly coordinated and addressed in a timely fashion. The ESS and the ITS were formed by the WEQ Executive Committee and were charged with developing both Business Practice Standards (ESS) and Communications Protocols (ITS), respectively. To the extent that the Interchange Subcommittee would like for NAESB to develop Business Practice Standards or Communications Protocols associated with Electronic Scheduling and/or Electronic Tagging (ETAG), such requests would certainly be considered within the scope of NAESB, consistent with the WEQ annual plan, and most likely assigned as necessary to the ESS and/or the ITS.

As NERC transitions to Reliability Standards from its current set of Policies, there are certainly many questions regarding the ongoing evolution of the existing Policies, tools, and practices. NAESB will continue to work with NERC to determine the best approach for answering these questions. Specifically, we would like to understand the process through which NERC, NAESB, and the IRC plan to coordinate and manage changes and enhancements to E-Tag, NERC Policy 3, and NERC Policy 9. We believe these to be the most critical overlapping areas of reliability and market influences, and encourage the swift resolution of the question of how to manage them as we move forward.

In the meantime, the ESS and the ITS encourage the Interchange Subcommittee to make a determination as to how it would like to initiate standards development on the issues mentioned in the January 19th letter. The Interchange Subcommittee or other group within NERC can either request the initiation formally (via the submission of a completed NAESB Request for Standard) or informally (via a letter that simply requests NAESB to begin working on those issues). If you decide to take the latter course, the ESS and/or the ITS will scope out the request and submit the appropriate NAESB Requests for Standard as required. Either way, NAESB will submit those requests to the JIC and, assuming they are assigned back to NAESB, will incorporate those requests into their annual work plan.

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If you have any additional questions, please feel free to contact either the NAESB Office or one of the chairs of the ESS and ITS.

Sincerely,

ESS/ITS Chairs

ESS Chairs:	ITS Chairs:
John Simonelli	Monroe Landrum
Andy Rodriquez	Alan Johnson
Joel Dison	

cc: Michael Desselle, WEQ Board Vice Chair
Lou Oberski, WEQ Executive Committee Vice Chair

OASIS Recommendation and Notational Ballot

RECOMMENDATION TO NAESB WEQ EXECUTIVE COMMITTEE

Requester: Southern Company Services
Request No.: R04005
Date: December 29, 2003

1. Action:

_X_Accept as requested
____Accept as modified below
____Decline
__X Change to Existing Practice
___Status Quo

2. TYPE OF MAINTENANCE

Per Request:	**Per Recommendation:**
_X_ Initiation	__X_Initiation
____Modification	____Modification
____Interpretation	____Interpretation
____Withdrawal	____Withdrawal
____Principle (x.1.z)	____Principle (x.1.z)
____Definition (x.2.z)	____Definition (x.2.z)
_X_Business Practice Standard (x.3.z)	__X Business Practice Standard (x.3.z)
___Document (x.4.z)	____Document (x.4.z)
____Data Element (x.4.z)	____Data Element (x.4.z)
____Code Value (x.4.z)	____Code Value (x.4.z)
____X12 Implementation Guide	____X12 Implementation Guide
____Business Process Documentation	____Business Process Documentation

3. RECOMMENDATION

SUMMARY:

Accept as requested the current Business Practice Standards and Communication Protocols for Open Access Same-Time Information System (OASIS) adopted in FERC Orders 605, 638 and 889.

STANDARDS LANGUAGE:

Section 2 Standard Terminology for Transmission and Ancillary Services

Section 2.1 Attribute Values Defining the Period of Service

The data templates of the Phase IA Standards & Communication Protocols (S&CP) Document have been developed with the use of standard service attributes in mind. What the Phase IA S&CP Document does not offer are specific definitions for each

attribute value. This section offers standards for these service attribute definitions to be used in conjunction with the Phase IA data templates.

Fixed services are associated with transmission services whose periods align with calendar periods such as a day, week, or month. Sliding services are fixed in duration, such as a week or month, but the start and stop time may slide. For example a Sliding week could start on Tuesday and end on the following Monday. Extended allows for services in which the start time may slide and also the duration may be longer than a standard length. For example an Extended week of service could be nine consecutive days. Various transmission service offerings using these terms are defined in Standards 2.1.1 through 2.1.14 below. Next_Increment indicates the next available full Service_Increment, such as the next hour, next day, or next week. Next_Increment is added at this time to address Next Hour Market Service, but may be used in the future to denote other products.

Table 1-1 identifies the standard terminology in OASIS Phase IA for the attributes SERVICE_INCREMENT (Hourly, Daily, Weekly, Monthly, and Yearly) and TS_WINDOW (Fixed, Sliding, Extended, and Next_Increment). Values shown in Table 1-1 as N/A (Not Applicable) are not sufficiently common in the market to require standards.

Next Hour Market Service, a new pro forma service, is denoted as having a Service Increment of Hourly and a TS_WINDOW of Next_Increment.

Table 1-1
Standard Service Period Attribute Values in Phase IA

	Fixed	**Sliding**	**Extended [1]**	**Next_Increment**
Hourly	X	N/A	N/A	X[2]
Daily	X	X	X	N/A
Weekly	X	X	X	N/A
Monthly	X	X	X	N/A
Yearly	X	X	X	N/A

[1]Included in the Phase IA S&CP Data Dictionary, Version 1.3, issued September 29, 1998.

[2]Next Hour Market Service is identified by Service Increment = Hourly and TS_WINDOW = Next_Increment

The existence of an attribute value in this table does not imply the services must be offered by a Transmission Provider. Requirements as to which services must be offered are defined by regulation and tariffs. Likewise, absence of a service period value in Table 1-1 does not restrict a Transmission Provider from offering a service. The intent of the table is to establish common terminology associated with standard products.

Each service period value assumes a single time zone specified by the Transmission Provider. It is recognized that daylight time switches must be accommodated in practice, but they have been omitted here for the purpose of simplicity.

Standard 2.1: A Transmission Provider shall use the values and definitions below for the service period attributes, SERVICE_INCREMENT AND TS_WINDOW for all transmission services offered on OASIS, or shall post alternative service period values and associated definitions on the OASIS Home Page at http://www.tsin.com, or shall use existing attribute values and definitions posted by other Transmission Providers. (See Section 3 for registration requirements.)

Standard 2.1.1: FIXED HOURLY - The service starts at the beginning of a clock hour and stops at the end of a clock hour.

Standard 2.1.2: FIXED DAILY - The service starts at 00:00 and stops at 24:00 of the same calendar date (same as 00:00 of the next consecutive calendar date).

Standard 2.1.3: FIXED WEEKLY - The service starts at 00:00 on Monday and stops at 24:00 of the following Sunday (same as 00:00 of the following Monday).

Standard 2.1.4: FIXED MONTHLY - The service starts at 00:00 on the first date of a calendar month and stops at 24:00 on the last date of the same calendar month (same as 00:00 of the first date of the next consecutive month).

Standard 2.1.5: FIXED YEARLY - The service starts at 00:00 on the first date of a calendar year and ends at 24:00 on the last date of the same calendar year (same as 00:00 of the first date of the next consecutive year).

Standard 2.1.6: SLIDING DAILY - The service starts at the beginning of any hour of the day and stops exactly 24 hours later at the same time on the next day.

Standard 2.1.7: SLIDING WEEKLY - The service starts at 00:00 of any date and stops exactly 168 hours later at 00:00 on the same day of the next week.

Standard 2.1.8: SLIDING MONTHLY - The service starts at 00:00 of any date and stops at 00:00 on the same date of the next month (28-31 days later). If there is no corresponding date in the following month, the service stops at 24:00 on the last day of the next month.

For example: SLIDING MONTHLY starting at 00:00 on January 30 would stop at 24:00 on February 28 (same as 00:00 March 1).

Standard 2.1.9: SLIDING YEARLY - The service starts at 00:00 of any date and stops at 00:00 on the same date of the following year. If there is no corresponding date in the following year, the service stops at 24:00 on the last day of the same month in the following year.

For example SLIDING YEARLY service starting on February 29 would stop on February 28 of the following year.

Standard 2.1.10: EXTENDED DAILY - The service starts at any hour of a day and stops more than 24 hours later and less than 168 hours later.

Standard 2.1.11: EXTENDED WEEKLY - The service starts at 00:00 of any date and stops at 00:00 more than one week later, but less than four weeks later.

Standard 2.1.12: EXTENDED MONTHLY - The service starts at 00:00 of any date and stops at 00:00 more than one month later, but less than twelve months later.

Standard 2.1.13: EXTENDED YEARLY - The service starts at 00:00 of any date and stops at 00:00 more than one year later, but must be requested in increments of full years.

Standard 2.1.14: NEXT_INCREMENT HOURLY – The service starts at the beginning of the next clock hour and stops at the end of that clock hour.

Section 2.2 Attribute Values Defining Service Class

Standard 2.2: A Transmission Provider shall use the values and definitions below to describe the service class, TS_CLASS, for transmission services offered on OASIS, or shall post alternative TS_CLASS attribute values and associated definitions on the OASIS Home Page at http://www.tsin.com, or shall use the attribute values and definitions posted by other Transmission Providers. (See Section 3 for registration requirements.)

> **Standard 2.2.1**: FIRM - Transmission service that always has priority over NONFIRM transmission service and includes Native Load Customers, Network Customers, and any transmission service not classified as non-firm in accordance with the definitions in the pro forma tariff.
>
> **Standard 2.2.2:** NON-FIRM - Transmission service that is reserved and/or scheduled on an as-available basis and is subject to curtailment or interruption at a lesser priority compared to FIRM transmission service, including Native Load Customers and Network Customers, in accordance with the definitions in the pro forma tariff.

Section 2.3 Attribute Values Defining Service Types

Standard 2.3: A Transmission Provider shall use the values and definitions below to describe the service type, TS_TYPE, for transmission services offered on OASIS, or shall post alternative attribute values and associated definitions on the OASIS Home Page at http://www.tsin.com, or shall use the attribute values and definitions posted by other Transmission Providers. (See Section 3 for registration requirements.)

> **Standard 2.3.1:** POINT-TO-POINT (PTP) - Transmission service that is reserved and/or scheduled between specified POINTS OF RECEIPT and DELIVERY pursuant to Part II of the pro forma tariff and in accordance with the definitions in the pro forma tariff.
>
> **Standard 2.3.2:** NETWORK - Network Integration Transmission Service that is provided to serve a Network Customer load pursuant to Part III of the pro forma tariff and in accordance with the definitions in the pro forma tariff.

Section 2.4 Curtailment Priorities

Standard 2.4: A Transmission Provider that has adopted NERC TLR Procedures shall use the curtailment priority definitions contained in NERC TLR Procedures for NERC CURTAILMENT PRIORITY (1-7) for all transmission services offered on OASIS. A Transmission Provider that has adopted alternative curtailment procedures shall post its alternative attribute values and associated definitions on the OASIS Home Page at http://www.tsin.com, or shall use attribute values and definitions posted by another Transmission Provider. (See Section 3 for registration requirements.)

Section 2.5 Other Service Attribute Values

The Commission has defined six ancillary services in Order No. 888. Other services may be offered pursuant to filed tariffs.

Standard 2.5: A Transmission Provider shall use the definitions below to describe the AS_TYPEs offered on OASIS, or shall post alternative attribute values and associated definitions on the OASIS Home Page at http://www.tsin.com, or shall use attribute values and definitions posted by another Transmission Provider. (See Section 3 for registration requirements.)

FERC Ancillary Services Definitions

Standard 2.5.1: SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE (SC) - is necessary to the provision of basic transmission service within every control area. This service can be provided only by the operator of the control area in which the transmission facilities used are located. This is because the service is to schedule the movement of power through, out of, within, or into the control area. This service also includes the dispatch of generating resources to maintain
generation/load balance and maintain security during the transaction and in accordance with section 3.1 (and Schedule 1) of the pro forma tariff.

Standard 2.5.2: REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE (RV) - is the provision of reactive power and voltage control by generating facilities under the control of the control area operator. This service is necessary to the provision of basic transmission service within every control area and in accordance with section 3.2 (and Schedule 2) of the pro forma tariff.

Standard 2.5.3: REGULATION AND FREQUENCY RESPONSE SERVICE (RF) - is provided for transmission within or into the transmission provider's control area to serve load in the area. Customers may be able to satisfy the regulation service obligation by providing generation with automatic generation control capabilities to the control area in which the load resides and in accordance with section 3.3 (and Schedule 3) of the pro forma tariff.

Standard 2.5.4: ENERGY IMBALANCE SERVICE (I) - is the service for transmission within and into the transmission provider's control area to serve load in the area. Energy imbalance represents the deviation between the scheduled and actual delivery of energy to a load in the local control area over a single hour and in accordance with section 3.4 (and Schedule 4) of the pro forma tariff.

Standard 2.5.5: OPERATING RESERVE - SPINNING RESERVE SERVICE (SP) - is provided by generating units that are on-line and loaded at less than maximum output. They are available to serve load immediately in an unexpected contingency, such as an unplanned outage of a generating unit and in accordance with section 3.5 (and Schedule 5) of the pro forma tariff.

Standard 2.5.6: OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE (SU) - is generating capacity that can be used to respond to contingency situations. Supplemental reserve, is not available instantaneously, but rather within a short period (usually ten minutes). It is provided by generating units that are on-line but unloaded, by quick-start generation, and by customer interrupted load and in accordance with section 3.6 (and Schedule 6) of the pro forma tariff.

Other Service Definitions

Other services may be offered to Transmission Customers through Commission-approved revisions to their individual open access tariffs. Examples of other services that may be offered include the Interconnected Operations Services described below in Standards 2.5.7, 2.5.8, and 2.5.9. Ancillary service definitions may be offered pursuant to an individual transmission provider's specific tariff filings.

Standard 2.5.7: DYNAMIC TRANSFER (DT) - is the provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of its Host Control Area into a different Electronic Control Area.

Standard 2.5.8: REAL POWER TRANSMISSION LOSSES (TL) - is the provision of capacity and energy to replace energy losses associated with transmission service on the Transmission Provider's system.

Standard 2.5.9: SYSTEM BLACK START CAPABILITY (BS) - is the provision of generating equipment that, following a system blackout, is able to start without an outside electrical supply. Furthermore, BLACK START CAPABILITY is capable of being synchronized to the transmission system such that it can provide a startup supply source for other system capacity that can then be likewise synchronized to the transmission system to supply load as part of a process of re-energizing the transmission system.

Standard 2.6: A Transmission Provider shall use the definitions below to describe the scheduling period leading up to the start time of a transaction:

Standard 2.6.1: SAME-DAY is after 2 p.m. of the preceding day and

Standard 2.6.2: NEXT-HOUR is one hour or less prior to the service start time.

Section 3 OASIS Registration Procedures

Section 3.1 Entity Registration

Operation of OASIS requires unambiguous identification of parties.

Standard 3.1: All entities or persons using OASIS shall register the identity of their organization (including DUNS number) or person at the OASIS Home Page at http://www.tsin.com. Registration identification shall include the parent entity (if any) of the registrant. Registration shall be a prerequisite to OASIS usage and renewed annually and whenever changes in identification occur and thereafter. An entity or person not complying with this requirement may be denied access by a transmission provider to that transmission provider's OASIS node.

The registration requirement applies to any entity logging onto OASIS for the purpose of using or updating information, including Transmission Providers, Transmission Customers, Observers, Control Areas, Security Coordinators, and Independent System Operators.

Section 3.2 Process to Register Non-Standard Service Attribute Values

Section 2 of the OASIS business practice standards addresses the use of standard terminology in defining services on OASIS. These standard definitions for service attribute values will be posted publicly on the OASIS Home Page at http://www.tsin.com and may be used by all Transmission Providers to offer transmission and ancillary services on OASIS. If the Transmission Provider determines that the standard definitions are not applicable, the Transmission Provider may register new attribute values and definitions on the OASIS Home Page. Any Transmission Provider may use the attribute values and definitions posted by another Transmission Provider.

Standard 3.2: Providers of transmission and ancillary services shall use only attribute values and definitions that have been registered on the OASIS Home Page at http://www.tsin.com for all transmission and ancillary services offered on their OASIS.

Standard 3.3: Providers of transmission and ancillary services shall endeavor to use on their OASIS nodes attribute values and definitions that have been posted by other Transmission Providers on the OASIS Home Page at http://www.tsin.com whenever possible.

Section 3.3 Registration of Points of Receipt and Delivery

In order to improve coordination of path naming and to enhance the identification of commercially available connection points between Transmission Providers and regions, the business practice for Phase IA OASIS requires that:

I. Transmission Providers register at the OASIS Home Page at http://www.tsin.com, all service points (Points of Receipt and Delivery) for which transmission service is available over the OASIS.

II. Each Transmission Provider would then indicate on its OASIS node, for each Path posted on its OASIS node, the Points of Receipt and Delivery to which each Path is connected.

A Transmission Provider is not required to register specific generating stations as Points of Receipt, unless they were available as service points for the purposes of reserving transmission service on OASIS. The requirement also does not include registration of regional flowgates, unless they are service points for the purposes of reserving transmission on OASIS.

Standard 3.4: A Transmission Provider shall register and thereafter maintain on the OASIS Home Page at http://www.tsin.com all Points of Receipt and Delivery to and from which a Transmission Customer may reserve and schedule transmission service.

Standard 3.5: For each reservable Path posted on their OASIS nodes, Transmission Providers shall indicate the available Point(s) of Receipt and Delivery for that Path. These Points of Receipt and Delivery shall be from the list registered on the OASIS Home Page at http://www.tsin.com.

Standard 3.6: When two or more Transmission Providers share common Points of Receipt or Delivery, or when a Path connects Points of Receipt and Delivery in neighboring systems, the Transmission Providers owning and/or operating those facilities shall apply consistent names for those connecting paths or common paths on the OASIS.

Section 4 On-line Negotiation and Confirmation Process

Section 4.1 On-line Price Negotiation in Short-term Markets

Standard 4.1: Consistent with FERC policy and regulations, all reservations and price negotiations shall be conducted on OASIS.

Standard 4.2: Reserved

Standard 4.3: Reserved

Section 4.2 Phase IA Negotiation Process State Transition Diagram

The Phase IA S&CP Document provides a process state diagram to define the Customer and Transmission Provider interactions for negotiating transmission service. This diagram defines allowable steps in the reservation request, negotiation, approval and confirmation.

Standard 4.4: The state diagram appearing in Exhibit 4-1 in Section 4.2.10.2 of the Version 1.3 of the S&CP Document constitutes a recommended business practice in OASIS Phase IA.

Standard 4.5: The definitions in Section 4.2.10.2 of the Version 1.3 of the S&CP Document (status values) shall be applied to the process states in OASIS Phase IA.

Table 4-1 – Reserved

Section 4.3 Negotiations Without Competing Bids

The following practices are defined in order to enhance consistency of the reservation process across OASIS Phase IA nodes.

Standard 4.6: A Transmission Provider/Seller shall respond to a Customer's service request, consistent with filed tariffs, within the Provider Response Time Limit defined in **Table 4-2 Reservation Timing Requirements.** The time limit is measured from the time the request is QUEUED. A Transmission Provider may respond by setting the state of the reservation request to one of the following:

I. INVALID
II. DECLINED
III. REFUSED
IV. COUNTEROFFER
V. ACCEPTED
VI. STUDY (when the tariff allows), leading to REFUSED, COUNTEROFFER, or ACCEPTED.

Standard 4.7: Prior to setting a request to ACCEPTED, COUNTEROFFER, or REFUSED a Transmission Provider shall evaluate the appropriate resources and ascertain that the requested transfer capability is (or is not) available.

Standard 4.8: For any request that is REFUSED or INVALID, the Transmission Provider must indicate in the SELLER_COMMENTS field the reason the request was refused or invalid.

Standard 4.9: The Customer may change a request from QUEUED, RECEIVED, STUDY, COUNTEROFFER, REBID, or ACCEPTED to WITHDRAWN at any time prior to CONFIRMED.

Standard 4.10: From ACCEPTED or COUNTEROFFER, a Customer may change the status to CONFIRMED or WITHDRAWN. In addition, a Customer may change the status from COUNTEROFFER to REBID. The Customer has the amount of time designated as Customer Confirmation Time Limit in **Table 4-2 Reservation Timing Requirements** to change the state of the request to CONFIRMED. The Customer time limit is measured from the first time the request is moved to ACCEPTED or COUNTEROFFER, and is not reset with subsequent iterations of negotiation.

Standard 4.11: After expiration of the Customer Confirmation Time Limit, specified in **Table 4-2 Reservation Timing Requirements,** the Transmission Provider has a right to move the request to the RETRACTED state.

Standard 4.12: Should the Customer elect to respond to a Transmission Provider's COUNTEROFFER by moving a reservation request to REBID, the Transmission Provider shall respond by taking the request to a DECLINED, ACCEPTED, or COUNTEROFFER state within the Provider Counter Time Limit, specified in **Table 42 Reservation Timing Requirements.** The Transmission Provider response time is measured from the most recent REBID time.

Standard 4.13: The following timing requirements shall apply to all reservation requests:

Table 4-2
Reservation Timing Requirements

Class	Service Increment	Time QUEUED Prior to Start	Provider Evaluation Time Limit[1]	Customer Confirmation Time Limit[2] after ACCEPTED or COUNTEROFFER[3]	Provider Counter Time Limit after REBID[4]
Non-Firm	Hourly	<1 hour	Best effort	5 minutes	5 minutes
Non-Firm	Hourly	>1 hour	30 minutes	5 minutes	5 minutes
Non-Firm	Hourly	Day ahead	30 minutes	30 minutes	10 minutes

Non-Firm	Daily	N/A	30 minutes	2 hours	10 minutes
Non-Firm	Weekly	N/A	4 hours	24 hours	4 hours
Non-Firm	Monthly	N/A	2 days [5]	24 hours	4 hours
Firm	Daily	< 24 hours	Best effort	2 hours	30 minutes
Firm	Daily	N/A	30 days[6]	24 hours	4 hours
Firm	Weekly	N/A	30 days[6]	48 hours	4 hours
Firm	Monthly	N/A	30 days[6]	4 days	4 hours
Firm	Yearly	60 days [7]	30 days	15 days	4 hours

Notes for Table 4-2:

[1]Consistent with regulations and filed tariffs, measurement starts at the time the request is QUEUED.

[2]Confirmation time limits are not to be interpreted to extend scheduling deadlines or to override preexemption deadlines.

[3]Measurement starts at the time the request is first moved to either ACCEPTED or COUNTEROFFER. The time limit does not reset on subsequent changes of state.

[4]Measurement starts at the time the Transmission Customer changes the state to REBID. The measurement resets each time the request is changed to REBID.

[5]Days are defined as calendar days.

[6]Subject to expedited time requirements of Section 17.1 of the pro forma tariff. Transmission Providers shall make best efforts to respond within 72 hours, or prior to the scheduling deadline, whichever is earlier, to a request for Daily Firm Service received during period 2-30 days ahead of the service start time.

[7]Subject to Section 17.1 of the pro forma tariff, whenever feasible and on a nondiscriminatory basis, transmission providers should accommodate requests made with less than 60 days notice.

Section 4.4 Negotiations With Competing Bids for Constrained Resources

Competing bids exist when multiple requests cannot be accommodated due to a lack of available transmission capacity. One general rule is that OASIS requests should be evaluated and granted priority on a first-come-first-served basis established by OASIS QUEUED time. Thus, the first to request service should get it, all else being equal.

Exceptions to this first-come-first-served basis occur when there are competing requests for limited resources and the requests have different priorities established by FERC regulations and filed tariffs. Prior to the introduction of price negotiations, the attribute values that have served as a basis for determining priority include:

I. Type (Network, Point-to-point)
II. Class (Firm, Non-Firm)
III. Increment (Hourly, Daily, Weekly, Monthly, Yearly)
IV. Duration (the amount of time between the Start Date and the Stop Date)
V. Amount (the MW amount)

Under a negotiation model, price can also be used as an attribute for determining priority. The negotiation process increases the possibility that a Transmission Provider will be evaluating multiple requests that cannot all be accommodated due to limited resources. In this scenario, it is possible that an unconfirmed request with an earlier QUEUED time could be preempted (SUPERSEDED). For this to occur, the subsequent request would be of higher priority or of greater price.

Standard 4.14: Consistent with regulations and filed tariffs, the following are recommended relative priorities of Service Request Tiers[1]. Specific exceptions may exist in accordance with filed tariffs. The priorities refer only to negotiation of service and do not refer to curtailment priority.

4.14.1. Service Request Tier 1: Native load, Network, or Long-term Firm
4.14.2. Service Request Tier 2: Short-term Firm
4.14.3. Service Request Tier 3: Network Service From Non-designated Resources
4.14.4. Service Request Tier 4: Non-firm
4.14.5. Service Request Tier 5: Non-firm Point-to-point Service over secondary receipt and delivery points
4.14.6 Service Request Tier 6: Non-firm Next Hour Market Service

Standard 4.15: Consistent with regulations and filed tariffs, reservation requests shall be handled in a first-come-first-served order based on QUEUE_TIME.

[1]Note: The term Tier is introduced to avoid confusion with existing terms such as TS_CLASS.

Standard 4.16: Consistent with regulations and filed tariffs, Table 4-3 describes the relative priorities of competing service requests and rules for offering right-of-first-refusal. While the table indicates the relative priorities of two competing requests, it also is intended to be applied in the more general case of more than two competing requests.

Table 4-3
Priorities for Competing Reservation Requests

ROW	Request 1	Is Preempted by Request 2	Right of First Refusal
1	Tier 1: Long-term Firm, Native Load, and Network Firm	N/A - Not preempted by a subsequent request.	N/A
2	Tier 2: Short-term Firm	Tier 1: Long-term Firm, Native Load, and Network Firm, while Request 1 is conditional. Once Request 1 is unconditional, it may not be preempted.	No
3	Tier 2: Short-term Firm	Tier 2: Short-term Firm of longer term (duration), while Request 1 is conditional. Once Request 1 is unconditional, it may not be preempted. [1]	Yes, while Request 1 is conditional. Once Request 1 is unconditional, it may not be preempted and right of first refusal is not applicable.
4	Tier 3: Network Service From Non-Designated Resources	Tiers 1 and 2: All Firm (including Network).	No
5	Tier 4: All Non-Firm PTP	Tiers 1 and 2: All Firm (including Network).	No
6	Tier 4: All Non-Firm PTP	Tier 3: Network Service from Non-Designated Resources.	No
7	Tier 4: All Non-Firm PTP	Tier 4: Non-firm PTP of a longer term (duration) [1]. Except in the last hour prior to start (See Standard 4.23).	Yes [2]
8	Tier 4: All Non-Firm PTP	Tier 4: Non-firm PTP of equal term (duration) [1] and higher price, when Request 1 is still unconfirmed and Request 2 is received pre-confirmed. A confirmed non-firm PTP may not be preempted for another non-firm	Yes [3]

		request of equal duration. (See Standards 4.22 and 4.25.)	
9	Tier 5: Non-firm PTP Service over secondary receipt and delivery points.	Tier 5 can be preempted by Tiers 1 through 4.	No
10	Tier 6: Non-firm Next Hour Market Service	Tier 6 can be preempted by Tiers 1 through 5.	No

[1] Longer duration, in addition to being higher SERVICE_INCREMENT (i.e., WEEKLY has priority over DAILY), also may mean more multiples of the same SERVICE_INCREMENT (i.e., 3 days may have priority over 2 days). Multiple service increments must be at the same level of capacity.

[2] Right of first refusal when a subsequent request is received of a longer duration applies only if the first request is confirmed.

[3] Right of first refusal when a subsequent request is received of an equal duration and higher price applies only when the first request is unconfirmed and the subsequent request is received preconfirmed (see Standards 4.22 and 4.26).

Standard 4.17: For a request or reservation that is Superseded or Displaced, the Transmission Provider must indicate the Assignment Reference Number of the competing request and the reason for denial of service in the SELLER_COMMENTS field.

Standard 4.18: Given competing requests for a limited resource and a right-of-first-refusal is not required to be offered, the Transmission Provider may immediately move requests in the CONFIRMED state to DISPLACED, or from an ACCEPTED or COUNTEROFFER state to SUPERSEDED, if the competing request is of higher priority, based on the rules represented in Table 4-3. These state changes require dynamic notification to the Customer if the Customer has requested dynamic notification on OASIS.

Standard 4.19: In those cases where right-of-first-refusal is required to be offered, the Transmission Provider shall notify the Customer, through the use of a COUNTEROFFER, of the opportunity to match the subsequent offer.

Standard 4.20: A Customer who has been extended a right-of-first-refusal shall have a confirmation time limit equal to the lesser of a) the Customer Confirmation Time Limit in Table 4-2 or b) 24 hours.

Standard 4.21: A Transmission Provider shall apply all rights-of-first-refusal in a nondiscriminatory and open manner for all Customers.

Standard 4.22: Once a non-firm PTP request has been confirmed, it shall not be displaced by a subsequent non-firm PTP request of equal duration and higher price.

Standard 4.23: A confirmed, non-firm PTP reservation for the next hour shall not be displaced within one hour of the start of the reservation by a subsequent non-firm PTP reservation request of longer duration.

Standard 4.24: A Transmission Provider shall accept any reservation request submitted for an unconstrained Path if the Customer's bid price is equal to or greater than the Transmission Provider's posted offer price at the time the request was queued, even if
later requests are submitted at a higher price. This standard applies even when the first request is still unconfirmed, unless the Customer Confirmation Time Limit has expired for the first request.

Standard 4.25: Once an offer to provide non-firm PTP transmission service at a given price is extended to a Customer by the Transmission Provider, and while this first request is still unconfirmed but within the Customer Confirmation Time Limit, the Transmission Provider shall not preempt or otherwise alter the status of that first request on receipt of a subsequent request of the same Tier and equal duration at a higher price, unless the subsequent request is submitted as pre-confirmed.

Standard 4.26: If during a negotiation of service (i.e., prior to Customer confirmation) a subsequent pre-confirmed request for service over the same limited resource of equal duration but higher price is received, the Transmission Provider must COUNTEROFFER the price of service on the prior COUNTEROFFER or ACCEPTED price to match the competing offer, in order to give the first Customer an opportunity to match the offer. This practice must be implemented in a non-discriminatory manner.

Standard 4.27: Whenever a request or reservation is set to the state of Invalid, Refused, Declined, Superseded, Retracted, Annulled, or Displaced, the Transmission Provider or Seller shall enter the reason for the action in the SELLER_COMMENTS field.

Section 5 Procurement of Ancillary and Other Services

Section 5.1 Introduction

Phase IA OASIS data templates allow the coupling of ancillary service arrangements with the purchase of transmission service for the purpose of simplifying the overall process for Customers. Transmission Providers must indicate (consistent with filed tariffs), which services are MANDATORY (must be taken from the Primary Transmission Provider), REQUIRED (must be provided for but may be procured from alternative sources), or OPTIONAL (not required as a condition of transmission service).

The Transmission Customer should make known to the Transmission Provider at the time of the reservation request certain options related to arrangement of ancillary services. The Transmission Customer may indicate:

a. I will take all the MANDATORY and REQUIRED ancillary services from the Primary Transmission Provider
b. I will take REQUIRED ancillary services from Third Party Seller X
c. I would like to purchase OPTIONAL services
d. I will self provide ancillary services
e. I will arrange for ancillary services in the future (prior to scheduling)

While these interactions are available in the Phase IA S&CP Document, there is a need to clarify the associated business practices. The standards in Section 5 apply to services defined in filed tariffs.

Section 5.2 Transmission Provider Requirements

Standard 5.1: The Transmission Provider shall designate which ancillary services are MANDATORY, REQUIRED, or OPTIONAL for each offered transmission service or each transmission path to the extent these requirements can be determined in advance of the submittal of a reservation request on a specific Path by a Transmission Customer.

Standard 5.2: A Transmission Provider shall modify a Transmission Customer's service request to indicate the Transmission Provider as the SELLER of any ancillary service, which is MANDATORY, to be taken from the Transmission Provider.

Standard 5.3: For REQUIRED and OPTIONAL services, the Transmission Provider shall not select a SELLER of ancillary service without the Transmission Customer first selecting that SELLER.

Standard 5.4: A Transmission Provider may accept a Transmission Customer's request for an ancillary service, which is not MANDATORY or REQUIRED, but shall indicate to the Transmission Customer at the time of acceptance in SELLER_COMMENTS that the service is not MANDATORY or REQUIRED.

Section 5.3 Transmission Customer Requirements

Standard 5.5: The Transmission Customer shall indicate with the submittal of a transmission reservation request, the preferred options for provision of ancillary services, such as the desire to use an alternative resource. The Transmission Provider shall post itself as the default ancillary service provider, if a Transmission Customer fails to indicate a third party SELLER of ancillary services. However, the Transmission Customer may
change this designation at a later date, so long as this change is made prior to the Transmission Provider's scheduling deadline.

Standard 5.6: A Transmission Customer may, but is not required to, indicate a third party SELLER of ancillary services, if these services are arranged by the Transmission Customer off the OASIS and if such arrangements are permitted by the Transmission Provider's tariff. The Transmission Provider shall post itself as the default ancillary service provider, if a Transmission Customer fails to indicate a third party SELLER of

ancillary services. However, the Transmission Customer may change this designation at a later date, so long as this change is made prior to the Transmission Provider's scheduling deadline.

Section 6 - Pathnaming Standards

Section 6.1 Introduction

The Data Element Dictionary of the OASIS S&CP Document, Version 1.3, defines a path name in terms of a 50-character alphanumeric string:

RR/TPTP/PATHPATHPATH/OPTIONALFROM-OPTIONALTOTO/SPR

RegionCode/TransmissionProviderCode/PathName/OptionalFrom-To(POR-POD)/Spare

This definition leaves it to the Transmission Providers to name the paths from their own perspective. The following standards provide an unambiguous convention for naming paths and will produce more consistent path names.

Section 6.2 Transmission Provider Requirements

Standard 6.1: A transmission provider shall use the path naming convention defined in the S&CP Data Dictionary for the naming of all reservable paths posted on OASIS.

Standard 6.2: A transmission provider shall use the third field in the path name to indicate the sending and receiving control areas. The control areas shall be designated using standard NERC codes for the control areas, separated by a hyphen. For example, the first three fields of the path name will be:

RR/TPTP/CAXX-CAYY/

Standard 6.3: A transmission provider shall use the fourth field of the path name to indicate POR and POD separated by a hyphen. For example, a path with a specific POR/POD would be shown as:

RR/TPTP/CAXX-CAYY/PORPORPORPOR-PODPODPODPOD/

If the POR and POD are designated as control areas, then the fourth field may be left blank (as per the example in 6.2).

Standard 6.4: A transmission provider may designate a sub-level for Points of Receipt and Delivery. For example, a customer reserves a path to POD AAAA. The ultimate load may be indeterminate at the time. Later, the customer schedules energy to flow to a particular load that may be designated by the transmission provider as a sub-level Point of Delivery. This option is necessary to ensure certain transmission providers are not precluded from using more specific service points by the inclusion of the POR/POD

in the path name. All sub-level PORs and PODs must be registered as such on http://www.tsin.com.

Section 7 – Next Hour Market Service

Section 7.1 Introduction

The standards in this section apply to the offering of Next Hour Market (NHM) Service only. The Commission has designated this service as voluntary for a transmission provider to offer. Therefore the standards apply to a transmission provider only if that provider offers NHM Service, in which case the standards become mandatory for that provider.

Section 7.2 Transmission Provider Requirements

Standard 7.1: Use of NHM Service shall be limited to interchange transactions having a duration of one clock-hour and requested no earlier than 60 minutes prior to the start time of the transaction.

Standard 7.2: A transmission provider offering NHM Service shall allow an eligible transmission customer to request a NHM Service reservation electronically using protocols compliant with the NERC ETAG Specification 1.6.

Standard 7.3: A transmission provider offering NHM Service shall allow a transmission customer to request NHM Service for one or more path segments of a tag by designating: (a) 0-NX as the transmission product code under the OASIS block and (b) BUYATMARKET as the OASIS reservation identifier.

Standard 7.4: A transmission provider offering NHM Service shall consider the submittal of a tag designating that provider on one or more path segments using NHM Service to include a pre-confirmed request for the necessary transmission reservation and associated mandatory ancillary services for each designated path segment, for the hour indicated. No additional confirmation steps shall be required by the transmission customer for a NHM Service transmission reservation and associated ancillary services.

Standard 7.5: A transmission provider offering NHM Service shall consider set the amount of the NHM Service reservation as:

a. The amount of the Transmission Provider Product, if specified.
b. In accordance with the Transmission Provider's tariff, the MW amount at the POR or POD for that Provider in the Loss Table, if Transmission Provider Product is not specified.
c. The MW amount in the Energy Profile, if neither Transmission Provider Product amount nor Provider Loss Table amounts are specified.

Standard 7.6: The OASIS queue time of a NHM Service request or reservation shall be the transmission provider ETAG approval service receipt time, unless a system failure requires the use of ETAG backup procedures, in which case the OASIS queue time shall be the time the tag is received by the transmission provider.

Standard 7.7: The 0-NX designation in the tag assigns as transmission customer, for all NHM Service path segments in the transaction, the PSE that is designated as the Purchasing-Selling Entity (PSE) responsible for the tag. A PSE submitting a tag may not designate a NHM Service reservation for another PSE and a transmission provider may not assign a reservation to any transmission customer other than the PSE submitting the NHM Service tag.

Standard 7.8: When evaluating competing requests for transmission reservations, a transmission provider offering NHM Service shall consider the NHM Service to have a priority lower than Tier 5 – point-to-point service over secondary receipt and delivery points.

Standard 7.9: Once a tag goes to IMPLEMENT or CONDITIONAL status in ETAG, the transmission provider shall consider the associated NHM Service reservations to be confirmed. Since the NHM Service confirmed reservation(s) are by definition less than one hour prior to start, these reservations shall not be displaced by a subsequent non-firm reservation of higher priority.

Standard 7.10: The transmission customer shall be obligated to pay for the transmission service under the terms of the tariff at the posted offer price for non-firm hourly service, once the interchange transaction tag is changed to the IMPLEMENT or CONDITIONAL status in ETAG. In the event of a voluntary withdrawal or reduction in the amount or duration of the service by the transmission customer after the tag has changed to IMPLEMENT or CONDITIONAL, the transmission customer shall remain obligated to pay for the full amount of the approved request. In the event of an involuntary curtailment or reduction of the service, initiated by the transmission provider or any other transmission provider, the transmission customer shall not be obligated to pay for any portions of the NHM Service that were involuntarily curtailed. In the case of involuntary curtailment or reduction, payment shall be based on a calculation of the MWhours actually used.

Standard 7.11: In the case that a transaction uses NHM Service for all required path segments in the tag, the default condition of the tag is NOT approved unless all required transmission providers and control areas indicate tag approval.

Standard 7.12: In the case that a transaction mixes one or more transaction path segments that use NHM Service with one or more path segments that use other types of transmission service, then 1) as long as the NHM Service path segment(s) are not fully approved, then the tag shall default to NOT approved; and 2) if all NHM Service path segments in the ETAG are fully approved, then the tag shall revert to the normal default status as specified in NERC Operating Policy 3 and associated Appendices.

Standard 7.13: The transmission customer shall be required to submit a NHM Service transaction request prior to the tag submittal time limit as specified in NERC Operating Policy 3 and associated Appendices, and no earlier than 60 minutes prior to the start of the transaction.

Standard 7.14: The approval mechanism for a NHM Service reservation shall be the tag approval. If the tag is approved and moved to the IMPLEMENT or CONDITIONAL state, all required NHM Service transmission reservations associated with that tag shall be considered confirmed reservations. If one or more transmission providers do NOT approve their segment(s) of the transaction, then the transaction shall be considered NOT approved. Each transmission provider designated in a tag that does not approve that segment of the tag shall indicate that the associated reservation for that segment is REFUSED. If a designated transmission provider in a NHM Service path segment approves the tag but the tag is not approved through the action or inaction of another transmission provider, then that transmission provider shall indicate that reservation is ANNULLED.

Standard 7.15: The transmission provider shall assign the reservation request and final disposition status on behalf of the transmission customer within one hour of the requested start of the NHM Service transaction, regardless of the ultimate disposition of the tag.

Standard 7.16: NHM Service shall have the lowest curtailment priority in the event that a curtailment or reduction of transfers is initiated. Specifically, NHM Service (0-NX) shall have a NERC Curtailment Priority of 0.

Standard 8. A Responsible Party may not deny or restrict access to an OASIS user merely because that user makes automated computer-to-computer file transfers or queries, or extensive requests for data.

Standard 9. In the event that an OASIS user's grossly inefficient method of accessing an OASIS node or obtaining information from the node seriously degrades the performance of the node, a Responsible Party may limit a user's access to the OASIS node without prior Commission approval. The Responsible Party must immediately contact the OASIS user to resolve the problem. Notification of the restriction must be made to the Commission within two business days of the incident and include a description of the problem. A closure report describing how the problem was resolved must be filed with the Commission within one week of the incident.

Standard 10. In the event that an OASIS user makes an error in a query, the Responsible Party can block the affected query and notify the user of the nature of the error. The OASIS user must correct the error before making any additional queries. If there is a dispute over whether an error has occurred, the procedures in the preceding paragraph apply.

Standard 11. Transmission Providers must provide "read only" access to the OASIS to Commission staff and to the staff of State regulatory authorities, at no cost, after such staff members have complied with the requisite registration procedures.

Standard 12. The information posted on the OASIS must be in such detail and the OASIS must have such capabilities as to allow Transmission Customers to:

(a) Clearly identify the degree to which transmission service requests or schedules were denied or interrupted;

(b) Obtain access, in electronic format, to information to support available transmission capability calculations and historical transmission service requests and schedules for various audit purposes; and

(c) Make file transfers and automated computer-to-computer file transfers and queries as defined by the Standards and Communications Protocols Document.

Standard 13. Information to support any such curtailment or interruption, including the operating status of the facilities involved in the constraint or interruption, must be maintained and made available upon request, to the curtailed or interrupted customer, the Commission's Staff, and any other person who requests it, for three years.

Standard 14. Each OASIS user must notify the Responsible Party one month in advance of initiating a significant amount of automated queries. The OASIS user must also notify the Responsible Party one month in advance of expected significant increases in the volume of automated queries.

Standard 15. § 37.1 Applicability.

This part applies to any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce and to transactions performed under the pro forma tariff required in Part 35 of this Chapter.

Standard 16. § 37.2 Purpose.

(a) The purpose of this part is to ensure that potential customers of open access transmission service receive access to information that will enable them to obtain transmission service on a non-discriminatory basis from any Transmission Provider. These rules provide standards of conduct and require the Transmission Provider (or its agent) to create and operate an Open Access Same-time Information System (OASIS) that gives all users of the open access transmission system access to the same information.

(b) The OASIS will provide information by electronic means about available transmission capability for point-to-point service and will provide a process for requesting transmission service. OASIS will enable Transmission Providers and Transmission Customers to communicate promptly requests and responses to buy and sell available transmission capacity offered under the Transmission Provider's tariff.

Standard 17. § 37.3 Definitions.

(a) Transmission Provider means any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce.

(b) Transmission Customer means any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service.

(c) Responsible Party means the Transmission Provider or an agent to whom the Transmission Provider has delegated the responsibility of meeting any of the requirements of this Part.

(d) Reseller means any Transmission Customer who offers to sell transmission capacity it has purchased.

(e) Wholesale Merchant Function means the sale for resale, or purchase for resale, of electric energy in interstate commerce.

(f) Affiliate means:

(1) for any exempt wholesale generator, as defined under section 32(a) of the Public Utility Holding Company Act of 1935, as amended, the same as provided in section 214 of the Federal Power Act; and

(2) for any other entity, the term affiliate has the same meaning as given in § 161.2(a) of this Chapter.

Standard 18. § 37.4 Standards of conduct.

A Transmission Provider must conduct its business to conform with the following standards:

(a) General Rules

(1) Except as provided in paragraph (a)(2) of this section, the employees of the Transmission Provider engaged in transmission system operations must function independently of its employees, or the employees of any of its affiliates, who engage in Wholesale Merchant Functions.

(2) Notwithstanding any other provisions in this section, in emergency circumstances affecting system reliability, Transmission Providers may take whatever steps are necessary to keep the system in operation. Transmission Providers must report to the Commission and on the OASIS each emergency that resulted in any deviation from the standards of conduct, within 24 hours of such deviation.

(b) Rules governing employee conduct

(1) Prohibitions. Any employee of the Transmission Provider, or any employee of an affiliate, engaged in wholesale merchant functions is prohibited from:

(i) conducting transmission system operations or reliability functions; and

(ii) having access to the system control center or similar facilities used for transmission operations or reliability functions that differs in any way from the access available to other open access Transmission Customers.

(2) Transfers. Employees engaged in either (i) wholesale merchant functions or (ii) transmission system operations or reliability functions are not precluded from transferring between such functions as long as such transfer is not used as a means to circumvent the standards of conduct of this section. Notices of any employee transfer to or from transmission system operations or reliability functions must be posted on the OASIS as provided in § 37.6 (g)(3). The information to be posted must include: the name of the transferring employee, the respective titles held while performing each function (i.e., on behalf of the Transmission Provider and wholesale merchant or affiliate), and the effective date of the transfer. The information posted under this section must remain on the OASIS for 90 days.

(3) Information Access. Any employee of the Transmission Provider, or of any of its affiliates, engaged in wholesale merchant functions:

(i) shall have access to only that information available to the Transmission Provider's open access transmission customers (i.e., the information posted on an OASIS), and must not have preferential access to any information about the Transmission Provider's transmission system that is not available to all users of an OASIS; and

(ii) is prohibited from obtaining information about the Transmission Provider's transmission system (including information about available transmission capability, price, curtailments, ancillary services, and the like) through access to information not posted on the OASIS that is not otherwise also available to the general public without restriction, or through information through the OASIS that is not also publicly available to all OASIS users.

(4) Disclosure. A Transmission Provider is responsible for ensuring compliance with the following provisions:

(i) Any employee of the Transmission Provider, or any employee of an affiliate, engaged in transmission system operations or reliability functions may not disclose to employees of the Transmission Provider, or any of its affiliates, engaged in wholesale merchant functions any information concerning the transmission system of the Transmission Provider or the transmission system of another (including information received from non-affiliates or information about available transmission capability, price, curtailments, ancillary services, etc.) through non-public communications conducted off the OASIS, through access to information not posted on the OASIS that is not at the same time available to the general public without restriction, or through

information on the OASIS that is not at the same time publicly available to all OASIS users (such as E-mail).

(ii) If an employee of the Transmission Provider engaged in transmission system operations or reliability functions discloses information not posted on the OASIS in a manner contrary to the requirements of the standards of conduct, the Transmission Provider must immediately post such information on the OASIS.

(iii) A Transmission Provider may not share any market information, acquired from nonaffiliated Transmission Customers or potential nonaffiliated Transmission Customers, or developed in the course of responding to requests for transmission or ancillary service on the OASIS, with its own employees (or those of an affiliate) engaged in merchant functions, except to the limited extent information is required to be posted on the OASIS in response to a request for transmission service or ancillary services.

(5) Implementing Tariffs.

(i) Employees of the Transmission Provider engaged in transmission system operations or reliability functions must strictly enforce all tariff provisions relating to the sale or purchase of open access transmission service, if these provisions do not provide for the use of discretion.

(ii) Employees of the Transmission Provider engaged in transmission system operations must apply all tariff provisions relating to the sale or purchase of open access transmission service in a fair and impartial manner that treats all customers (including the public utility and any affiliate) in a non-discriminatory manner, if these provisions involve discretion.

(iii) The Transmission Provider must keep a log, available for Commission audit, detailing the circumstances and manner in which it exercised its discretion under any terms of the tariff.

(iv) The Transmission Provider may not, through its tariffs or otherwise, give preference to wholesale purchases or sales made on behalf of its own power customers, or those of an affiliate, over the interests of any other wholesale customer in matters relating to the sale or purchase of transmission service (including issues of price, curtailments, scheduling, priority, ancillary services, etc.).

(v) If the Transmission Provider offers a discount on purchases of transmission service made on behalf of its own power customers or those of any affiliate, then, at the same time, it must post on the OASIS an offer to provide the same discount to all Transmission Customers on the same path and on all unconstrained transmission paths.

(vi) If the Transmission Provider offers a rate discount on ancillary services to an affiliate, or attributes a discounted ancillary service rate to its own transactions, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all eligible customers.

(6) Books and Records. A Transmission Provider must maintain its books of account and records (as prescribed under Parts 101 and 125 of this Chapter) separately from those of its affiliates and these must be available for Commission inspection.

(c) Maintenance of written procedures. The Transmission Provider must maintain in a public place, and file with the Commission, current written procedures

implementing the standards of conduct in such detail as will enable customers and the Commission to determine that the Transmission Provider is in compliance with the requirements of this section.

Standard 19. § 37.5 Obligations of Transmission Providers and Responsible Parties.

(a) Each Transmission Provider is required to provide for the operation of an OASIS, either individually or jointly with other Transmission Providers, in accordance with the requirements of this Part. The Transmission Provider may delegate this responsibility to a Responsible Party such as another Transmission Provider, an Independent System Operator, a Regional Transmission Group, or a Regional Reliability Council.

(b) A Responsible Party must: (1) provide access to an OASIS providing standardized information relevant to the availability of transmission capacity, prices, and other information (as described in this Part) pertaining to the transmission system for which it is responsible; and

(2) shall operate the OASIS in compliance with the standardized procedures and protocols found in OASIS Standards and Communication Protocols, which can be obtained from the Public Reference and Files Maintenance Branch, Room 2A, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

(c) Transmission Providers must provide "read only" access to the OASIS to Commission staff and the staffs of State regulatory authorities, at no cost, after such staff members have complied with the requisite registration procedures.

Standard 20. § 37.6 Information to be posted on an OASIS.

(a) The information posted on the OASIS must be in such detail as to allow Transmission Customers to:

(1) make requests for transmission services offered by Transmission Providers, Resellers and other providers of ancillary services;

(2) view and download in standard formats, using standard protocols, information regarding the transmission system necessary to enable prudent business decision making;

(3) post, view, upload and download information regarding available products and desired services;

(4) clearly identify the degree to which their transmission service requests or schedules were denied or interrupted; and

(5) obtain access, in electronic format, to information to support available transmission capability calculations and historical transmission service requests and schedules for various audit purposes.

(b) Posting transmission capability. The transmission capability that is expected to be available on the Transmission Provider's system (ATC) and the total transmission capability (TTC) of that system shall be calculated and posted for each Posted Path as set out in this section.

(1) Definitions. For purposes of this section,

(i) Posted Path means any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted. For this last category, the posting must continue for 180 days

and thereafter until 180 days have elapsed from the most recent request for service over the requested path. For purposes of this definition, an hour includes any part of an hour during which service was denied, curtailed or interrupted.

(ii) Constrained Posted Path means any posted path having an ATC less than or equal to 25 percent of TTC at any time during the preceding 168 hours or for which ATC has been calculated to be less than or equal to 25 percent of TTC for any period during the current hour or the next 168 hours.

(iii) Unconstrained Posted Path means any posted path not determined to be a constrained posted path.

(2) Calculation methods, availability of information, and requests.

(i) Information used to calculate any posting of ATC and TTC must be dated and time-stamped and all calculations shall be performed according to consistently applied methodologies referenced in the Transmission Provider's transmission tariff and shall be based on current industry practices, standards and criteria.

(ii) On request, the Responsible Party must make all data used to calculate ATC and TTC for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (e.g., thermal, voltage, stability)) in electronic form within one week of the posting. The information is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. This information is to be retained for six months after the applicable posting period.

(iii) System planning studies or specific network impact studies performed for customers to determine network impacts are to be made publicly available in electronic form on request and a list of such studies shall be posted on the OASIS. A study is required to be provided only in the electronic format in which it was created, along with any necessary decoding instructions, at a cost limited to the cost of reproducing the material. These studies are to be retained for two years.

(3) Posting. The ATC and TTC for all Posted Paths must be posted in megawatts by specific direction and in the manner prescribed in this subsection.

(i) Constrained Posted Paths.

(A) For Firm ATC and TTC:

(1) The posting shall show ATC and TTC for a 30-day period. For this period postings shall be: by the hour, for the current hour and the 168 hours next following; and thereafter, by the day. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC and TTC will be posted daily for each period.

(2) Postings shall also be made by the month, showing for the current month and the 12 months next following.

(3) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following to the end of the planning horizon but not to exceed 10 years.

(B) For Non-Firm ATC and TTC. The posting shall show ATC and TTC for a 30-day period by the hour and days prescribed under paragraph (b)(3)(i)(A)(1) of this section and, if so requested, by the month and year as prescribed under paragraph (b)(3)(i)(A)(2) and (3) of this section.

(C) Updating Posted Information for Constrained Paths.

(1) The capability posted under paragraphs (b)(3)(i)(A) and (B) of this section must be updated when transactions are reserved or service ends or whenever the TTC estimate for the Path changes by more than 10 percent.

(2) All updating of hourly information shall be made on the hour.

(ii) Unconstrained Posted Paths.

(A) Postings of ATC and TTC shall be by the day, showing for the current day and the next six days following and thereafter, by the month for the 12 months next following. If the Transmission Provider charges separately for on-peak and off-peak periods in its tariff, ATC and TTC will be posted for the current day and the next six days following for each period. These postings are to be updated whenever the ATC changes by more than 20 percent of the Path's TTC.

(B) If planning and specific requested transmission studies have been done, seasonal capability shall be posted for the year following the current year and for each year following until the end of the planning horizon but not to exceed 10 years.

(c) Posting Transmission Service Products and Prices.

(1) Transmission Providers must post prices and a summary of the terms and conditions associated with all transmission products offered to Transmission Customers.

(2) Transmission Providers must provide a downloadable file of their complete tariffs in the same electronic format as the tariff is filed with the Commission.

(3) A Transmission Provider, within 24 hours of agreeing to sell transmission service to a non-affiliate at a discount (as measured from when ATC must be adjusted in response to the transaction), must post on the OASIS (and make available for download) information describing the transaction (including price, quantity, and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of the audit log required in section 37.7. With respect to any discount offered to its own power customers or its affiliates, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all Transmission Customers on the same path and on all unconstrained transmission paths.

(4) Customers choosing to use the OASIS to offer for resale transmission capacity they have purchased must post relevant information to the same OASIS as used by the one from whom the Reseller purchased the transmission capacity. This information must be posted on the same display page, using the same tables, as similar capability being sold by the Transmission Provider, and the information must be contained in the same downloadable files as the Transmission Provider's own available capability. A customer reselling transmission capacity without the use of an OASIS must, nevertheless, inform the original Transmission Provider of the transaction within the time limits prescribed by the "Sale or Assignment of Transmission Service" section of the pro forma tariff.

(d) Posting Ancillary Service Offerings and Prices.

(1) Any ancillary service required to be provided or offered under the pro forma tariff prescribed by Part 35 of this Chapter must be posted with the price of that service.

(2) A Transmission Provider, within 24 hours of agreeing to sell an ancillary service to a non-affiliate at a discount, must post on the OASIS (and make available for download) information describing the transaction (including price, quantity, and any other relevant terms and conditions) and shall keep such information posted on the OASIS for at least 30 days. A record of the transaction must be retained and kept available as part of the audit log required in § 37.7. As to discounts for ancillary services, if a Transmission Provider offers a rate discount to an affiliate, or attributes a discounted ancillary service rate to its own transactions, the Transmission Provider must, at the same time, post on the OASIS an offer to provide the same discount to all eligible customers.

(3) Any other interconnected operations service offered by the Transmission Provider may be posted, with the price for that service.

(4) Any entity offering an ancillary service shall have the right to post the offering of that service on the OASIS if the service is one required to be offered by the Transmission Provider under the pro forma tariff prescribed by Part 35 of this Chapter. Any entity may also post any other interconnected operations service voluntarily offered by the Transmission Provider. Postings by customers and third parties must be on the same page, and in the same format, as postings of the Transmission Provider.

(e) Posting Specific Transmission Service Requests and Responses.

(1) General Rules.

(i) All requests for transmission service offered by Transmission Providers under the pro forma tariff must be made on the OASIS. Requests for transmission service, and the responses to such requests, must be conducted in accordance with the Transmission Provider's tariff, the Federal Power Act, and Commission regulations.

(ii) In processing a request for transmission or ancillary service, the Responsible Party shall post the following information: the date and time when the request is made, its place in any queue, the status of that request, and the result (accepted, denied, withdrawn).

(iii) The identity of the parties will be masked -- if requested -- during the negotiating period and for 30 days from the date when the request was accepted, denied or withdrawn.

(2) Posting when a request for transmission service is denied.

(i) When a request for service is denied, the Responsible Party must provide the reason for that denial as part of any response to the request.

(ii) Information to support the reason for the denial, including the operating status of relevant facilities, must be maintained for 60 days and provided, upon request, to the potential Transmission Customer.

(iii) Any offer to adjust operation of the Transmission Provider's System to accommodate the denied request must be posted and made available to all Transmission Customers at the same time.

(3) Posting when a transaction is curtailed or interrupted.

(i) When any transaction is curtailed or interrupted, the curtailment or interruption must be posted (with the identities of the parties masked as required in § 37.6(e)(1)(iii)) and must state the reason why the transaction could not be continued or completed.

(ii) Information to support any such curtailment or interruption, including the operating status of the facilities involved in the constraint or interruption, must be maintained for 60 days and provided, upon request, to the curtailed or interrupted customer.

(iii) Any offer to adjust the operation of the Transmission Provider's system to restore a curtailed or interrupted transaction must be posted and made available to all curtailed and interrupted Transmission Customers at the same time.

(f) Posting Transmission Service Schedules Information. Information on transmission service schedules must be recorded by the entity scheduling the transmission service and must be available on the OASIS for download. Transmission service schedules must be posted no later than seven calendar days from the start of the transmission service.

(g) Posting Other Transmission-Related Communications.

(1) The posting of other communications related to transmission services must be provided for by the Responsible Party. These communications may include "want ads" and "other communications" (such as using the OASIS as a Transmission-related conference space or to provide transmission-related messaging services between OASIS users). Such postings carry no obligation to respond on the part of any market participant.

(2) The Responsible Party is responsible for posting other transmission-related communications in conformance with the instructions provided by the third party on whose behalf the communication is posted. It is the responsibility of the third party requesting such a posting to ensure the accuracy of the information to be posted.

(3) Posting Transfers. Notices of transfers of personnel as described in § 37.4(b)(2) shall be posted.

Standard 21. § 37.7 Auditing Transmission Service Information.

(a) All OASIS database transactions, except other transmission-related communications provided for under § 37.6(g)(2), must be stored, dated, and time stamped.

(b) Audit data must remain available for download on the OASIS for 90 days. The audit data are to be retained and made available upon request for three years from the date when they are first posted.

Standard 20. § 37.8 Implementation schedule for OASIS requirements; phases.

Each Transmission Provider must develop or participate in an OASIS that meets the requirements of this Part and that is in operation by November 1, 1996. Each Transmission Provider must be in compliance with the standards of conduct prescribed in § 37.4 by November 1, 1996.

The Standards are attached and provided as part of the following attached documents:

- Federal Energy Regulatory Commission Business Practice Standards for Open Access Same-Time Information System (OASIS) Transactions, Version 1.2, issued October 25, 2000 (Attachment A).
- Standards and Communication Protocols for Open Access Same-Time Information System (OASIS), Version 1.4, July 26, 2000 (Attachment B).
- Data Dictionary, Standards and Communication Protocols for Open Access Same-Time Information System (OASIS), Version 1.4, July 26, 2000 (Attachment C)
- Revisions to Section 4.2.10.2 of the S&CP Document, 4.2.10.2, Status Values (Attachment D).
- Oasis Version 1.4 corrections, outlined in a letter dated January 30, 2001, from Paul R. Sorenson, OSC Chair, to David P. Borgers, Office of the Secretary, Federal Energy Regulatory Commission (Attachment E).
- FERC Order 605 (Attachment F).
- FERC Order 889 (Attachment G).
- FERC Order 889 Appendix A Data Element Dictionary (Attachment H).
- FERC Order 889 Appendix B Request (Query) Variables (Attachment I).

4. SUPPORTING DOCUMENTATION

a. Description of Request:

Request submitted by Southern Company Services, proposing the WEQ's acceptance of the current OASIS Business Practice Standards and Communication Protocol Standards.

b. Description of Recommendation:

Recommend acceptance as requested.

c. Business Purpose:

The business practice standards are designed to implement the Commission's policy related to on-line price negotiation and to improve the commercial operation of the Open Access Same-Time Information System (OASIS).

d. Commentary/Rationale of Subcommittee(s)/Task Force(s):

North American Energy Standards Board

1301 Fannin, Suite 2350, Houston, Texas 77002
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: naesb@naesb.org
Home Page: www.naesb.org

NORTH AMERICAN ENERGY STANDARDS BOARD

WEQ Executive Committee Member Ballot
Notational Vote for Request R04005
February 24, 2004

USE THIS BALLOT IF YOU ARE AN WEQ EC MEMBER AND UNABLE TO ATTEND THE UPOMING EC MEETING BY PHONE OR IN PERSON.

Agreement? **(Yes/No/Abstain)**	Statement
	R04005: Accept as NAESB business practice standards the business practice standards listed in the recommendation R04005 that are reflected in FERC Orders 889, 605 and 638 and that represent OASIS.

Name: _____

Signature: _____

Company: _____

Date: _____

Please return to the NAESB Office by February 24, 2004
Fax: 713-356-0067

CIBP Recommendation and Supporting Documents

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

1. RECOMMENDED ACTION:

_X_ Accept as requested
___ Accept as modified below
___ Decline

EFFECT OF EC VOTE TO ACCEPT RECOMMENDED ACTION:

_X_ Change to Existing Practice
___ Status Quo

2. TYPE OF DEVELOPMENT/MAINTENANCE

Per Request:	**Per Recommendation:**
_X_ Initiation	_X_ Initiation
___ Modification	___ Modification
___ Interpretation	___ Interpretation
___ Withdrawal	___ Withdrawal
___ Principle	___ Principle
___ Definition	___ Definition
_X_ Business Practice Standard	_X_ Business Practice Standard
___ Document	___ Document
___ Data Element	___ Data Element
___ Code Value	___ Code Value
___ X12 Implementation Guide	___ X12 Implementation Guide
___ Business Process Documentation	___ Business Process Documentation

3. RECOMMENDATION

SUMMARY:

Accept as requested Business Practices that are consistent with the current version of NERC Policy 3, will complement NERC compliance templates associated with Policy 3, and will ultimately facilitate the implementation of the NERC Coordinate Interchange Reliability Standard currently under development as part of the NERC Standards process.

RECOMMENDATION TO NAESB EXECUTIVE COMMITTEE
For Quadrant: Wholesale Electric Quadrant

Requesters: **NAESB Members of the Joint Interface Committee**
Request No.: **R03013**
Request Title: **Coordinate Interchange Business Practices**

RECOMMENDED STANDARDS:

NAESB Coordinate Interchange Business Practice Standard
(Request For Interchange, RFI)

Background:
In light of the continuing restructuring of the Electric industry, and FERC's rulemakings to ensure open and non-discriminatory access to the nation's transmission systems, NERC is developing Reliability Standards to replace current Operating Policies and Procedures. A request for the development of a NAESB Business Practice Standard representing the Business Practices in Policy 3 and complementing NERC's Coordinate Interchange Standard was submitted in June, 2003. This Standard was approved by the Joint Interface Committee (JIC) representatives from NERC, NAESB, and RTO/ISO and assigned to NAESB for development.

The Standard is being developed using the Functional Model as a basis for defining the "Functions" necessary for Bulk Electric System reliability but also facilitates the existing NERC Operating Policies for "Control Areas".

Introduction:

This Standard is being developed to identify market-supported processes to facilitate fair & "equitable" competitive interchange practices. This standard will provide the necessary data and arrangements to the Interchange Authority and all involved parties of the Request for Interchange (RFI) for an Interchange Transaction to take place between Sink and Source Balancing Authorities (BA). This standard is designed to implement the flow of data and approval mechanisms to facilitate Interchange. It is not intended to supercede existing tagging protocols, but rather will facilitate both existing ETAG or any replacement protocols needed to implement the functional model. It should be understood this Standard covers the front-end business arrangements and requirements for an Interchange Transaction to take place. Upon receiving all approvals from the Approval Entities, the IA will utilize appropriate NERC policies or standards to transition the Arranged Interchange to a Confirmed Interchange and finally the implementation of the Confirmed Interchange.

Definitions

RFI Standard 1.0 For the purposes of this Standard, the following definitions shall be applied:

RFI Standard 1.1 Approval Entities – Those entities responsible for providing active approvals to an Arranged Interchange.

RFI Standard 1.2 Arranged Interchange – The state where completed and required information from the business arrangements are provided to and received by the Interchange Authority.

RFI Standard 1.3 Balancing Authority (BA) – The entity which performs the Balancing Function as defined by NERC. Until such time as the Balancing Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Control Area.

RFI Standard 1.4 Confirmed Interchange - The state where the Interchange Authority has verified the Arranged Interchange and is ready to submit it to the Balancing Authorities.

RFI Standard 1.5 Implemented Interchange- The state where the Balancing Authority enters the Confirmed Interchange into its area control error (ACE) equation.

RFI Standard 1.6 Implemented Interchange Block Accounting – Energy accounting that assumes a beginning and ending ramp time of zero minutes. For accounting purposes, this moves the energy associated with the starting and ending ramps into the adjacent starting and ending clock time of the Interchange.

RFI Standard 1.7 Interchange Authority (IA) – The entity which performs the Interchange Function as defined by NERC. Until such time as the Interchange Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective Tagging Authority for the sink Control Area for the requested Interchange.

RFI Standard 1.8 Interchange Transaction – A transaction representing the delivery of energy from a generator located within a Point of Receipt (POR) BA to a load located within a Point of Delivery (POD) BA.

RFI Standard 1.9 Market Adjustment – A desired modification to the energy and/or transmission profile during the Confirmed Interchange period.

RFI Standard 1.10 Market Period – The period of time when a Requesting PSE is making purchase, sale, and Transmission service arrangements needed to support a RFI.

RFI Standard 1.11 Point of Delivery BA – The Balancing Authority responsible for monitoring and/or controlling the load identified as the sink of an Interchange Transaction.

RFI Standard 1.12 Point of Receipt BA – The Balancing Authority responsible for monitoring and/or controlling the generation identified as the source of an Interchange Transaction.

RFI Standard 1.13 Reliability Authority- The entity which performs the Reliability Authority functions as defined by NERC. Until such time as the Reliability Authority becomes a certified Function under the NERC Functional Model, these duties shall be performed by the respective appropriate reliability entity.

RFI Standard 1.14 Reliability Period – The segment of time from when the IA has received the RFI from the requesting PSE to physical implementation (beginning of ramp time).

RFI Standard 1.15 Request For Interchange, RFI- Process of providing required data as defined in the NAESB RFI Datasheet to the IA for the purpose of implementing a bilateral Interchange Transaction.

RFI Standard 1.16 Requesting PSE – The PSE submitting the Request For Interchange (RFI). Under current policy this entity would be called the "Tag Author".

RFI Standard 1.17 Transaction Correction – Modifications to non-reliability data of a Request For Interchange (RFI) while in the Arranged Interchange period. This non-reliability data is located in the NAESB RFI Datasheet and is labeled as "correctable".

RFI Standard 1.18 Transmission Service Provider- Approves or denies transmission service requests from PSEs, Generator Owners, and LSEs. This entity also administers the transmission tariff and provides transmission service agreements.

Business Practices

RFI Standard 2.0 All requests to implement an Interchange Transaction shall be accomplished by the submission of a completed "Request For Interchange", RFI, to the Interchange Authority (IA). Upon receipt of the RFI, the IA shall immediately forward the RFI to all involved parties of the RFI.

RFI Standard 2.1 All energy purchase, energy sale, and Transmission service arrangements necessary to implement the completed RFI shall be performed during the Market Period.

RFI Standard 2.2 Until such time as other protocols are established by NERC and/or NAESB, submission of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A4.

RFI Standard 3.0 While any Purchasing Selling Entity (PSE) may act as the "Requesting PSE", it shall be the responsibility of the load serving Purchasing-Selling-Entity (PSE), or their designee, to ensure that the completed RFI has been submitted to the IA.

RFI Standard 4.0 A completed RFI shall contain, at a minimum, the required information specified in the most current version of the **NAESB RFI Datasheet** (attached).

RFI Standard 5.0 On behalf of the Requesting PSE, the IA shall verify approvals from all involved Approval Entities (e.g. TSP-for transmission reservations, BA-for ramping start/end times and rate, RA-reliability analysis, Generator/Load PSE) prior to being confirmed and implemented in accordance with the NERC Coordinate Interchange Standard.

RFI Standard 5.1 The Requesting PSE shall submit required RFI information and data in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable** (attached).

RFI Standard 5.2 Until such time as other protocols are established by NERC and/or NAESB, timing requirements for the submission and approval of the completed RFI shall be in accordance with NERC Policy 3 Appendix 3A1.

RFI Standard 6.0 All requests for approval/validation of the completed RFI by the IA during the Arranged Interchange Period shall be assessed in accordance with the timing requirements of the most current version of the **NAESB RFI Submission and Response Timetable.** The results of that assessment shall be promptly communicated by the IA back to all involved parties.

RFI Standard 6.1 Any denial of a RFI request by any Approval Entity shall be communicated to the IA and Requesting PSE and accompanied by the reason for such denial.

RFI Standard 7.0 The IA shall be responsible for communicating changes on the status of the RFI to all involved parties of the RFI, including BAs, IAs, RAs, counterparty PSE (Generator or Load Serving), and the TSPs, and the PSEs holding the associated transmission rights necessary to support the transaction.

RFI Standard 8.0 The primary method for submitting a RFI to the IA shall be by electronic means using protocols to be determined by NAESB.

RFI Standard 8.1 A backup or redundant electronic system shall be available for immediate use should the primary electronic means become disabled.

RFI Standard 8.2 Submitting a RFI to the IA via facsimile is acceptable only as a last resort when the electronic means and its required backup or redundant system are not available.

RFI Standard 8.3 Until such time as NERC and/or NAESB establish replacement protocols, the preferred method of submitting data to the IA shall be the most current version of the NERC E-Tag Specifications.

RFI Standard 9.0 The PSE who created the RFI shall be allowed to submit a Transaction correction to the RFI during the Arranged Interchange Period in accordance with the **NAESB RFI Submission and Response Timetable**.

RFI Standard 9.1 Market adjustments made during the Confirmed Interchange Period by the PSE must be submitted to the IA who immediately communicates the revised request to all involved parties of the RFI. Timing of the approval assessment on the market adjustment by the Approval Entities shall be in accordance with the NAESB **RFI Submission and Response Timetable**. If denied by any Approval Entity, the original request remains valid.

RFI Standard 10.0 Each PSE submitting a RFI for an Interchange Transaction shall have, or arrange to have, personnel on site and immediately available 24 x 7 for notification of Interchange Transaction changes.

RFI Standard 10.1 These personnel shall be available from the beginning of the Market Period until the end of the Implementation Period.

RFI Standard 11.0 Energy accounting for all RFIs shall be accomplished via Implemented Interchange Block Accounting.

RFI Standard 12.0 Settlement of losses shall be either handled as financial or as payment in-kind.

RFI Standard 12.1 For losses handled as payment in-kind, the PSE shall communicate to the IA the mw losses and the entity the losses are with for each TSP along the transaction path.

RFI Standard 12.2 All bilateral transactions are equal and opposite in direction for a source and sink BA.

RFI Standard 13.0 Ramp rates shall be standard across the North American Interconnections.

RFI Standard 13.1 Ramp rate for the Eastern Interconnection shall be 10 minutes equally across the start and end times of the Transaction unless otherwise agreed to by all parties involved in the Transaction.

RFI Standard 13.2 Ramp rate for the Western Interconnection shall be 20 minutes equally across the start and end times of the Transaction unless otherwise agreed to by all parties involved in the Transaction.

RFI Standard 14.0 For Dynamic Transfer Transactions, the requirements shall be established by NERC.

See also Attachments:

- NAESB RFI Datasheet
- NAESB RFI Submission and Response Timetable

4. SUPPORTING DOCUMENTATION

a. Description of Request:

Request submitted by the NAESB Members of the Joint Interface Committee requesting complementary business practice standards to support NERC's Coordinate Interchange Business Practices Standard.

b. Description of Recommendation:

WEQ Standards Review Subcommittee

On 7/10/03, the WEQ Standards Review Subcommittee established the Coordinate Interchange Business Practices Task Force, which is charged with scoping issues and developing standards pursuant to Request No. R03013 to support the Coordinate Interchange Standards being developed by NERC.

WEQ Coordinate Interchange Business Practices Task Force

On 7/29/03, the CIBPTF began its scoping work by looking at both the work of NERC's Coordinate Interchange Standard Drafting Team and current NERC Policy 3 to identify areas within the policy that have market implications. The CIBPTF completed a scoping document that was sent out for industry comment on 8/19/03.

NAESB-NERC-IRC Joint Interface Committee

On 9/18/03 the Joint Interface Committee determined through a unanimous motion to forward Request R03013 to NAESB for development.

WEQ Coordinate Interchange Business Practices Task Force

The review of NERC Policy 3 concluded at the 10/27-28/03 Joint Meeting of the NERC Interchange Subcommittee, NERC Coordinate Interchange Standards Drafting Team, and NAESB CIBPTF.

WEQ Executive Committee

In early January 2004 the WEQ Executive Committee re-assigned the CIBP to report to the WEQ Electronic Scheduling Subcommittee, in recognition of the transition of the task force from scoping to standards drafting.

WEQ Coordinate Interchange Business Practices Task Force

On 12/02/03 a strawman standard was begun, revised on 1/21/04, and further revised on 2/12/04.

WEQ Electronic Scheduling Subcommittee

On 2/17-18/04 the ESS considered the RFI standard and unanimously adopted the following motion:

> The ESS recommends to the EC the passage of the Coordinate Interchange Business Practice Standard as presented by the CIBPTF, and modified in the February 17-18, 2004 ESS meeting. The Recommended standard shall be posted for public comment until April 2, 2004 and considered at the May EC meeting. The ESS will review public comments on this proposed standard at its scheduled April 5-7 meeting and, if necessary, make recommendations to the EC regarding any modifications to the standard arising from that review.

c. Business Purpose:

The Business Practices will provide market participants with procedures for providing any necessary data for the analysis of interchange, as defined by NERC for reliability purposes, including data format and timing of data submittals.

d. Commentary/Rationale of Subcommittee(s)/Task Force(s):

The WEQ Electronic Scheduling Subcommittee found the Request For Interchange (RFI) Standard to be consistent with the current version of NERC Policy 3, will complement NERC compliance templates associated with Policy 3, and will ultimately facilitate the implementation of the NERC Coordinate Interchange Reliability Standard currently under development as part of the NERC Standards process.The Coordinate Interchange Business Practices Task Force (CIBPTF) and WEQ Electronic Scheduling Subcommittee met on the following days and to prepare the document and recommendation and all work papers may be found on the following web pages (http://naesb.org/weq/weq_cibp.asp and http://naesb.org/weq/weq_electronic_scheduling.asp):

• July 29, 2003	Conference Call	CIBPTF
• October 21, 2003	Conference Call	CIBPTF
• October 27-28, 2003	Meeting	CIBPTF
• December 2, 2003	Meeting	CIBPTF
• January 21, 2004	Meeting	CIBPTF
• February 17-18, 2004	Meeting	ESS

NAESB RFI Submission and Response Timetable

Document Subsections

A. Eastern Interconnection – New Transactions
B. Western Interconnection – New Transactions
C. Interchange Transaction Corrections
D. Interchange Transaction Modifications

A. Eastern Interconnection – New Transactions

The table below represents the recommended business practices for RFI submission to the IA deadlines within the Eastern Interconnection. These are default requirements; some regulatory or provincially approved provider practices may have requirements that are more stringent. Under these instances, the more restrictive criteria shall be adhered to.

Table 1: Eastern Interconnection – Timing Requirements

Transaction Duration	PSE Submit Deadline*	Actual RFI Submission Time	Approval Entity Assessment Time	Time to Start of Transaction
Less than 24 Hours	20 Minutes prior to start	≤1 Hour prior to start	≤ 10 Minutes from tag receipt	≥ 10 Min
		>1 to <4 hours prior to start	≤20 Minutes from tag receipt	≥ 40 Min
		≥ 4 Hours prior to start	≤ 2 Hours from tag receipt	≥ 2 Hours
24 Hours or longer	4 Hours prior to start	Any	≤ 2 Hours from tag receipt	≥ 2 Hours
*Start time references are for start of the TRANSACTION not the start of the ramp.				

B. Western Interconnection – New Transactions

The tables below represent the recommended business practices for RFI submission deadlines to the IA within the Western Interconnection. These are default requirements. The tables describe the various minimum submission and assessment timing requirements.

Table 2: Western Interconnection – Timing Requirements

Transaction Start/Submittal Time	PSE Submit Deadline	Actual RFI Submission Time*	Approval Entity Assessment Time	Approval/Denial Notes	Time to Start of Transaction*
Start 00:00 next day or beyond when submitted prior to 18:00 of the current day	15:00 day prior to start	Any	3 hours	Passive Approval if submitted before deadline, else Passive Denial. Deferred denial	≥ 6 Hours
Start 00:00 next day and submitted between 18:00 and 23:59:59 on day prior to start – OR – start within current day		≥ 4 Hours prior to start	2 Hours from RFI receipt	Passive Approval Deferred denial	≥ 2 Hours
		<4 Hours to ≥1 Hour prior to start	20 minutes from RFI receipt	Passive Approval Deferred denial	≥ 40 Min
		<1 hour to ≥30 minutes prior to start	10 minutes from RFI receipt	Passive Approval Deferred denial	≥ 20 Min
		<30 minutes to ≥20 minutes prior to start	10 minutes from RFI receipt	Passive Approval Deferred denial	≥ 10 Min
	20 minutes prior to start	<20 minutes prior to start	5 minutes from RFI receipt	Passive Denial. Deferred denial	Submission time minus maximum time of 5 minutes

Notes/Clarification:

1. **All clock times are in PPT.**
2. **RFI falling under the criteria in yellow are deemed pre-schedule requests.**
3. **RFI falling under the criteria in green are deemed real-time requests.**
4. **Pre-schedule requests submitted between 15:00 and 18:00 will be assigned LATE composite status.**
5. **Real-time requests submitted after 20 minutes prior to the start of the Transaction will be assigned LATE composite status.**

***Start-time references are for start of the Transaction, not the start of the ramp.**

C. Interchange Transaction Corrections

TRANSACTION Corrections may be provided by the PSE to the IA to replace non-reliability data listed in a RFI. As each correction is received, the Evaluation Time of the TRANSACTION will extend, based on the following rules:

- Each correction shall extend the evaluation time by ten minutes
- At no time can the evaluation time be extended past the start time of the TRANSACTION.
- Each correction shall reset the approval status of those entities affected by the correction
- The segment or segments corrected will be eligible for passive approval if the correction is received within the timelines specified below, except in the case where the TRANSACTION has already been set for passive denial. The segment or segments corrected will be subject to passive denial if the correction is not received within the timelines specified below. At no point may a TRANSACTION segment already under Passive Denial constraints be returned to Passive Approval eligibility.

Table 3: Correction Submission Requirements*

Eastern Interconnection	Western Interconnection
20 minutes prior to start	30 minutes prior to start
***Start time references are for start of the Transaction not the start of the ramp.**	

D. Interchange Transaction Modifications

Market-initiated modifications, and other TRANSACTION modifications that affect energy profiles must be received by and evaluated within certain times. The following tables describe the submission and evaluation requirements for such changes.

Modification requests received by the deadlines specified below shall be considered "on time," and are eligible for active Approval. Modification requests received past the deadlines shall be considered "late," and are considered denied unless explicitly approved by all parties.

Table 4: Eastern Interconnection – Modifications

Modification Type	Requestor Submission Deadline***	Actual Submission Time***	Evaluation Time
Reliability (Curtailments or Reloads)	**20 minutes prior to modification start****	**Less than 30 minutes to start**	**10 minutes**
		30 minutes or more prior to start	**15 minutes**
Market – Committed Transmission Reservation(s) Reductions	**N/A**	**N/A**	**N/A**
Market – Committed Transmission Reservation(s) Increases, Energy Reductions, Energy Increases*	**20 minutes prior to modification start****	**Less than 30 minutes to start**	**10 minutes**
		30 minutes or more prior to start	**15 minutes**
***Start time references are for start of the Transaction not the start of the ramp.**			

Table 5: Western Interconnection – Modifications

Modification Type	Requestor Submission Deadline***	Actual Submission Time***	Evaluation Time
Reliability (Curtailments or Reloads)	**25 minutes prior to modification start****	**Less than 30 minutes to start**	**10 minutes**
		30 minutes or more prior to start	**15 minutes**
Market – Committed Transmission Reservation(s) Reductions	**N/A**	**N/A**	**N/A**
Market – Committed Transmission Reservation(s) Increases, Energy Reductions, Energy Increases*	**25 minutes prior to modification start****	**Less than 30 minutes to start**	**10 minutes**
		30 minutes or more prior to start	**15 minutes**
***Start time references are for start of the Transaction not the start of the ramp.**			

*See Special Exception for Cancellations below

**If received after deadline, requires active approval or will be passively denied

Special Exception for Cancellations

A cancellation is defined as setting both committed transmission reservation(s) and energy flow to zero for the duration of the TRANSACTION **prior** to the start of a TRANSACTION but **following** that TRANSACTIONS approval. In the event that a PSE elects to cancel a TRANSACTION, the following timelines should be utilized:

Table 6: Special Exception for Cancellations Submission and Evaluation Timing

Region	Submission Deadline*	Evaluation Time
Eastern Interconnection	**15 minutes prior to transaction start**	**If received by deadline, no evaluation required. Request is automatically approved.**
		If not received by deadline, request is not eligible for Special Exception for Cancellations, and must be processed normally.
Western Interconnection	**20 minutes prior to transaction start**	**If received by deadline, no evaluation required. Request is automatically approved.**
		If not by deadline, request is not eligible for Special Exception for Cancellations, and must be processed normally.
***Start time references are for start of the Transaction not the start of the ramp.**		

NAESB RFI Datasheet
(Request For Interchange)
Required and Correctable Data

Version 1

A. New Requests For Interchange
B. Market Related Profile Modifications (Market Adjustment)

A. New Requests For Interchange

A **new RFI** is an RFI that has not yet been implemented or confirmed for implementation. Such RFI must be presented to those entities that are responsible for the implementation of the RFI in order that they may **evaluate** the Request and determine whether or not it can be implemented. The following information is to be used to describe such a RFI.

1. Market Information

1.1. **Financial Path (Required)** – the description of financially responsible parties for the transaction in order. This will typically start with a GPE and finish with a LSE, with optionally Intermediate PSE'S between the two.

1.1.1. **Energy Title Holder(s) (Required)** – the identity of the entities financially responsible to take and/or deliver the energy as described in the physical path. This will typically start with a GPE and finish with a LSE, with optionally Intermediate PSE'S between the two.

1.1.1.1. Energy Product Type (Correctable) – the type of energy delivered by the Energy Title Holder.

1.1.1.2. Contract Number(s) (Correctable) – reference to a TRANSACTION entered into by the Energy Title Holder with one or more other participants in the RFI.

1.1.1.3. Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.

2. Physical Information

2.1. **Physical Path (Required)** – the description of physically scheduling parties for the transaction in order and related to the financially responsible parties described above. This will always contain a Generation segment, at least one Transmission segment, and a LOAD segment.

2.1.1. **Generation (Required)** – set of data describing the physical and contractual characteristics of the energy source.

2.1.1.1. **Resource Service Point (Required)** – the physical point at which the energy is being generated. This may vary in granularity, dependent on local business practices.

2.1.1.2. Contract Number(s) (Correctable) – reference to a schedule or agreement entered into by the Generation Providing Entity and the Generator Operator.

2.1.1.3. Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.

2.1.1.4. **Energy Profile (Required)** – energy to be produced by the generator for this RAI.

2.1.2. **Transmission (Required)** – set of data describing the physical and contractual characteristics of a wheel (import, export, or through).

2.1.2.1 **Transmission Provider (Required)** – the identity of the transmission provider that is wheeling the energy.

- Point of Receipt -POR (Correctable) – valid Point of Resource for scheduled Transmission Reservation.
- Point of Delivery - POD (Correctable) – valid Point of Delivery for scheduled Transmission Reservation.
- Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.
- Scheduling Entity(ies) (Correctable) – entities that are physically scheduling interchange on behalf of the TRANSMISSION PROVIDER in order to provide wheeling services.
- **Loss Provision Information (Required)** (Correctable)– Information describing the manner in which losses are accounted for. Losses will either be paid back In-Kind or Financially.
- Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.
- **POR and POD Profiles (Required)** – schedule of Energy Flow imported at the Point of Receipt and Exported at the Point of Delivery.
- **Transmission Reservation Number(s) (Required)** (Correctable) – reference to a particular transmission reservation being used to provide transmission capacity to support the transaction being described.
    - **Transmission Product (Required)** (Correctable) – Specifies the NERC Priority.
    - **Transmission Customer (Required)** (Correctable) – identifies the entity that purchased and holds the transmission reservation being presented for use.
    - **Transmission Reservation Profile (Required)** - information describing the transmission reservation commitment associated with the TRANSMISSION PROVIDER.

2.1.3. **Load (Required)** – set of data describing the physical and contractual characteristics of the energy sink.

2.1.3.1. **Resource Service Point (Required)** – the physical point at which the energy is being consumed. This may vary in granularity, dependent on local business practices.

2.1.3.2. Contract Number(s) (Correctable) – reference to a schedule or agreement entered into by the Load Serving Entity and the Load and/or Distributor.

2.1.3.3. Miscellaneous Information (Correctable) – information provided at the author's option regarding the RFI.

2.1.3.4. **Energy Profile (Required) –** energy to be consumed by the load for this RFI.

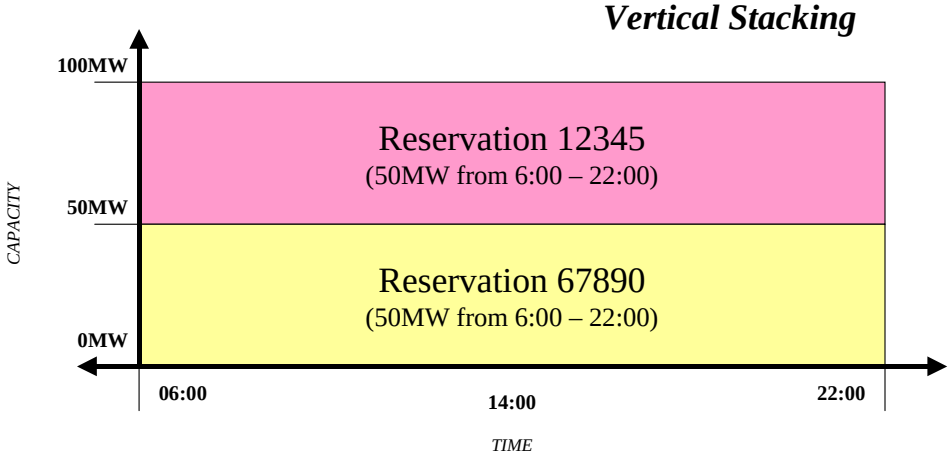
2.1.4 Using Multiple Transmission Reservations to Support a Single Leg of an Interchange Transaction

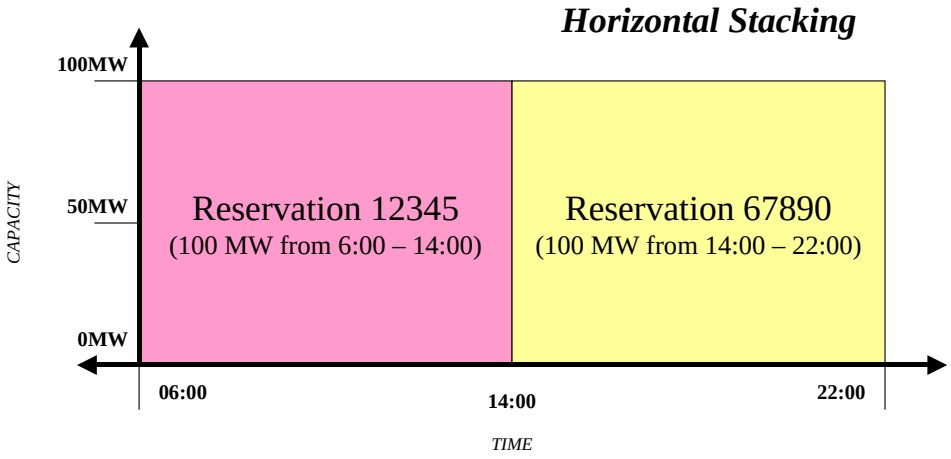
The use of multiple transmission reservations to support a single leg of an RFI is known as transmission **stacking**. There are two types of transmission stacking:

- Vertical stacking, in which a Transmission Customer combines multiple reservations to achieve a certain net level of transmission capacity, and
- Horizontal stacking, in which a Transmission Customer combines multiple reservations to achieve a certain transmission capacity coverage over time.

The following diagrams illustrate these concepts more fully. In both cases, the assumed need is 100 MW of transmission capacity for hours 06:00 through 22:00.

Vertical Stacking





Should a customer elect to utilize stacking, including any combination of the two stacking types, to support their RFI, they must understand the following requirements:

- Stacks MUST be described through fully qualified profiles for each reservation being used
- At no point may the coverage described by the stack be less than the transmission capacity needed for the RAI's energy flow

B. Market-Related Profile Modifications (Market Adjustment)

Profile Modifications are changes to a RFI's energy profile based on market desires. Such modifications must be presented to those entities that are responsible for the implementation of the modification in order that they may **evaluate** the RFI and determine whether or not the modification can be implemented. The following information must be used to describe such a modification.

- The RFI being modified
- All necessary profile changes to set the transmission capacity or energy flow to the desired levels during the appropriate hours (including the specification of new reservations to support the request, if necessary), and
- Contact information for the person that initiated the modification.

Presentations on OASIS 2 Plans and Vision

OASIS II
A Vision of the Future

NERC Trends

- **Implementing lessons learned from blackout**
- **Refocusing towards core reliability requirements**
  - **Rewriting Policies 5, 6, and 9**
- **Steering away from commercial requirements**
- **Refining the compliance model**
  - **Compliance templates**
- **Moving toward strategic vision**
  - **Implementation of the Functional Model**
  - **Enforceable Reliability Standards**

NAESB WEQ Trends

- **Emerging from start-up mode**
- **Proactive and responsive companion efforts to NERC reliability initiatives**
- **Re-defining priorities**
- **Finalizing strategic vision**
  - **Mitigating the impact of market "seams"**
  - **Combining transmission reservations and transaction scheduling (OASIS II)**
  - **Defining protocols?**

Key Areas of Risk
The Potential for Gaps

- **Timing Risks**
  - **Reliability Standards (and/or compliance templates) vs Business Practice Standards**
  - **Standards are implemented, but tools have not been developed**
- **Tool Risks**
  - **E-Tag or replacement**
  - **IDC or replacement**
  - **OASIS or replacement**
  - **Funding**
  - **Administrative**

Key Areas of Risk
The Potential for Gaps – con't

- **Transition Risks**
  - **Revisions to existing policies**
  - **Implementation of compliance templates**
  - **Maintenance of existing tools**
- **Congruency Risks**
  - **Business Practice Standards conflict with Reliability Standards**

Convergence is Critical

- **Timing**
  - **Reliability Standards and associated Business Practice Standards should be implemented concurrently**
- **Tools**
  - **Existing tools cannot be discarded if new tools are not available**
  - **"Throw-away" tools must be avoided where possible**
- **Transition**
  - **Smooth "handoffs" between NERC, NAESB, and the ISOs/RTOs are essential**
- **Congruency**
  - **Reconciliation process needs to be established**

OASIS II and the Functional Model

- Functional Model
  - Facilitates new market structures
  - Implementation horizon => Standards needed to certify functional entities are in place by 2007
- OASIS II:
  - The apex of the new market structure
  - The conjunction of reservations and scheduling
  - The ultimate market tool
  - Use Cases written to the functional model
  - Implementation horizon => no target date set

Recommendations

- Create a joint Strategic Vision
  - Implementation of OASIS II standards and protocols coincident with implementation of standards needed to certify functional entities under the Functional Model
  - Target date 2007/2008
- Establish a transition plan for business practices associated with Policies 3*, 5, and 9 (others?)
  - Establish BPS that work today and facilitate tomorrow
  - Use the proposed Coordinate Interchange Business Practice Standard* as a template

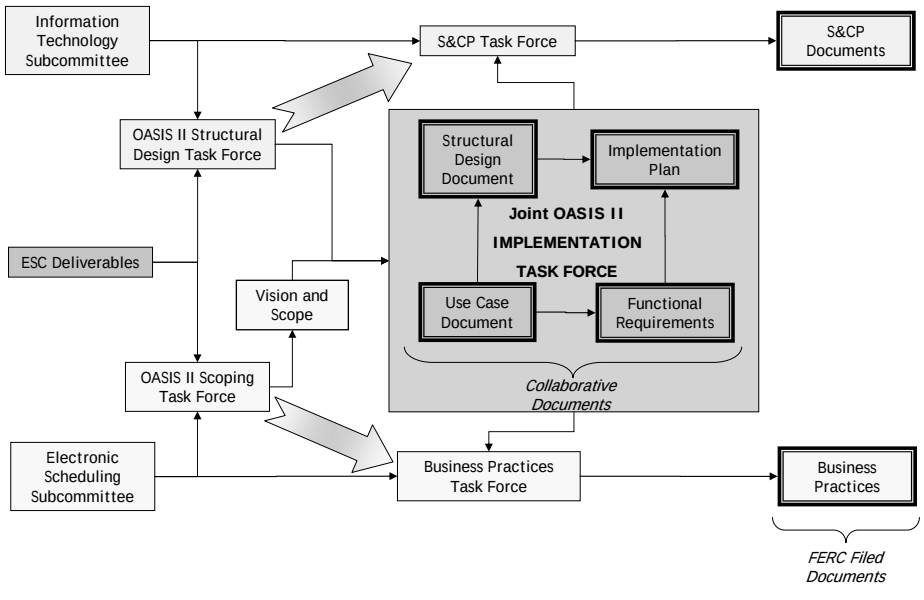
* BPs for Policy 3 have already been submit to the NAESB WEQ EC for passage

Recommendations - con't

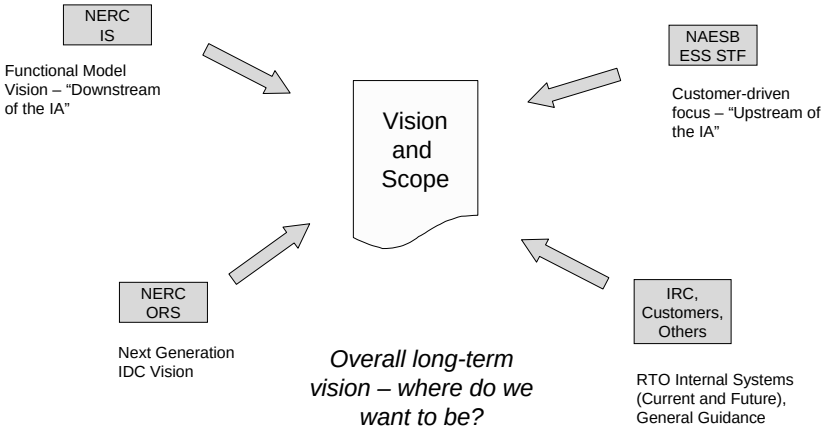
- Commit to maintaining existing tools until at least 2007*
- Establish a plan to develop appropriate market-based "congestion management" mechanisms that complement OASIS II by 2007*
- Resolve other high priority "seams" issues by 2007*

*or whatever the industry agrees to for a "convergence" date

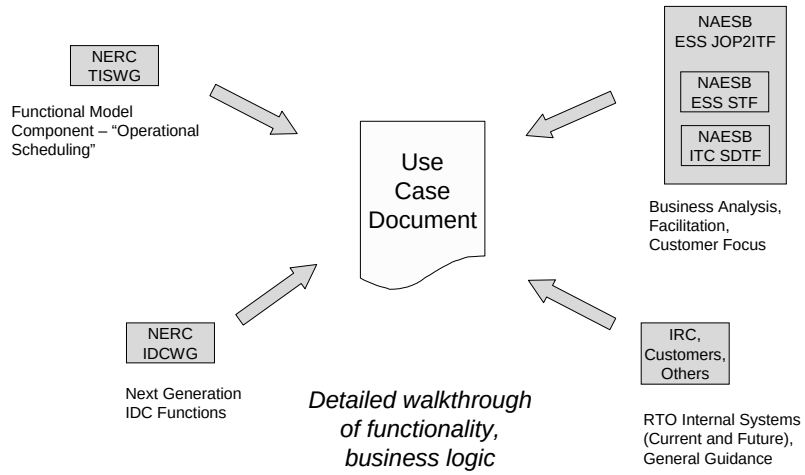
NAESB OASIS II Development Overview



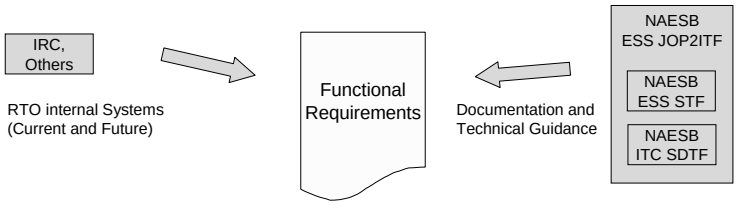
Vision and Scope



Use Case Document



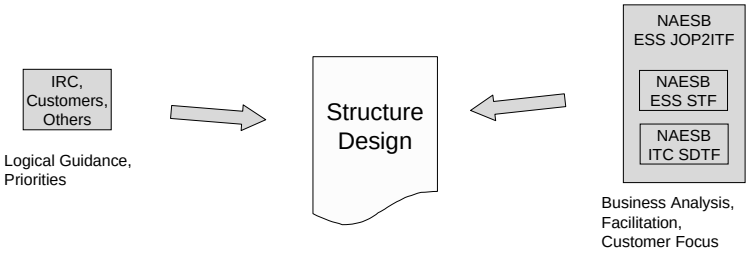
Functional Requirements



Beyond Use Cases – "blueprints" for S&CP

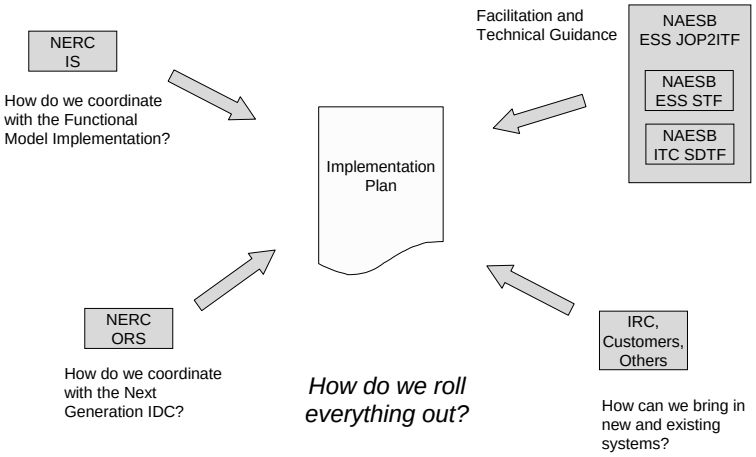
Includes System Requirements

Structure Design Document

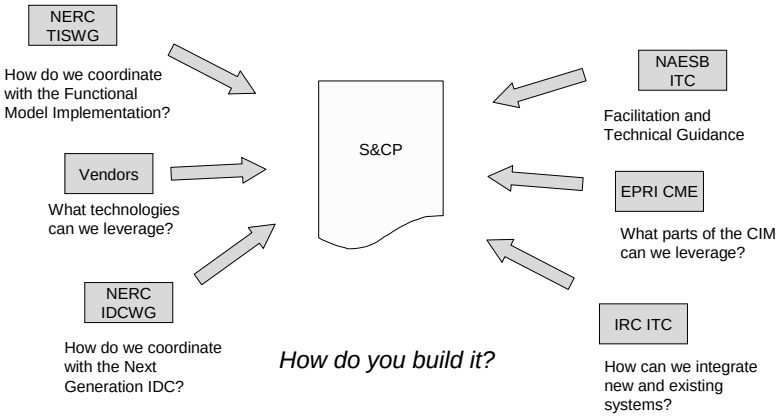


How do we want to organize the functional pieces?

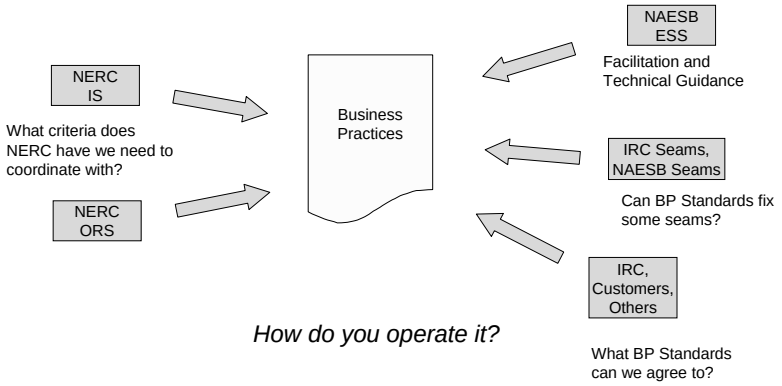
Implementation Plan



S&CP



Business Practices



How do you operate it?

Initial Phases – AJR thoughts

- Stage I
  - Bridges to legacy systems
  - Back-end systems needed to implement OASIS II and the Functional Model
- Stage II
  - OASIS Phase II Transmission Functions
  - Operational Scheduling tools for the Functional Model
  - IDC Next Generation
- Stage III
  - Market Interface
  - Electronic Scheduling

AJR Suggested Timeline

- Spring/Summer 2004 – Develop Functional Design Documents
  - Detailed Scope
  - ESC Use Cases
- Summer/Fall 2004 – Develop Strategic Architecture Plan
  - Modules
  - Compatibility plans and requirements
- Winter 2004 – Identify Implementation Plan
- 2005 – Design Stage I Components
- 2006 – Implement Stage I Components, Design Stage II Components
- 2007 – Implement Stage II Components, Design Stage III Components
- 2008 – Implement Stage III Components

OASIS Phase II
Approaching the Problem

General Discussion on Strategy and Philosophy
Andy Rodriquez - PJM

Presented to the NAESB ESS and ITS
February 16, 2004

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How did we get here?

- OASIS 1A
- Fax Tagging
- E-Mail Tagging
- Electronic Tagging
- XML Electronic Tagging

- OASIS Phase II/Electronic Scheduling ANOPR

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Core Objectives

- Customer-driven Development
- Incremental Value
- Cost Effective
- Market Design Neutral
- Encourage “seamless” boundaries whenever possible
- Leverage Existing Tools…

  without being bound by those tools

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How do we start?

- Begin with the ESC Use Cases
- Evaluate and Define OASIS functionality
- Identify Modular Components
- Determine Architecture
- Develop Approach

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Architecture

- This should NOT necessarily be a discussion on technical issues
- Focus should be on deployment strategy that meets core objectives
- Identify modular groups where appropriate

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Approach

- Should focus on incremental deliverables to provide ongoing value
- Staged approached to functionality will allow amortized cost burden to companies
- Can also be utilized to address regional diversity
  - If upgrades can be done on an incremental basis, we can work to ensure backward compatibility where possible

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Ongoing Efforts

- IDC – Next Generation
  - No dependence on tags
- CIM Market Extensions
  - Coordination between RTOs
- PJM/MISO Congestion Management
  - Quantifying internal dispatch
- Information Technology Council
  - Facilitated Checkouts, Other Initiatives

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Collaboration

- Should encourage participation to meet openness goals and ensure coordinated attack – minimal duplication of effort
  - NAESB Groups
    - Seams Collaborative
    - Information Technology Subcommittee
  - NERC Community
    - Interchange Subcommittee
    - Transaction Information Systems Working Group
    - Operations Reliability Subcommittee
    - Interchange Distribution Calculator Working Group
  - ISO/RTO Council
    - Information Technology Committee

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What is OASIS (my thoughts)?

- A market-oriented solution that optimizes the market interchange scheduling function
  - *This would be developed by NAESB*
- A reliability-oriented solution that meets the needs of the functional model with regard to operational interchange scheduling
  - *This would be developed by NERC*
- A set of interfaces to allow for market activity within a ISO/RTO/TP
  - *This would be developed by the ISO/RTO/TP, but would align with the NAESB functions*
- A "market/reliability interface" between the two, called the Interchange Authority, that would tie markets and reliability together
  - *This would jointly be developed by NERC, NAESB, and the IRC*

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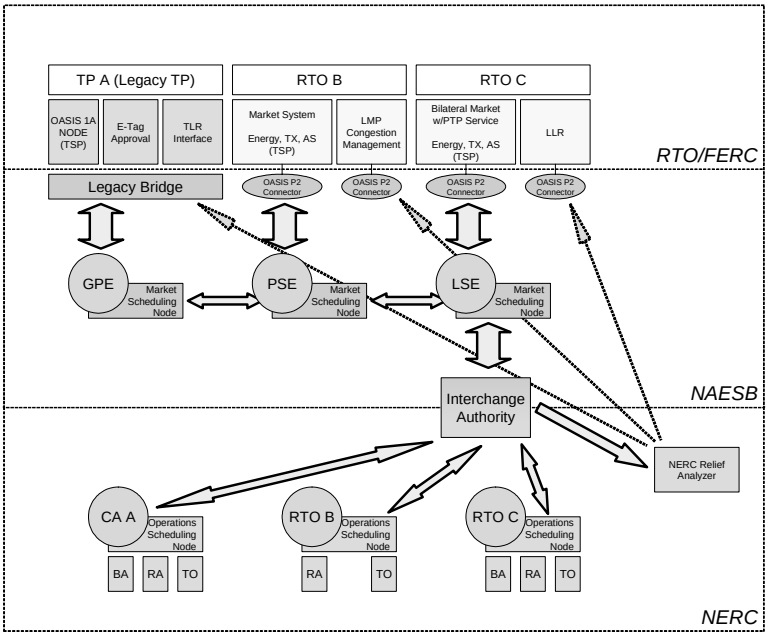
Proposed Vision



Suggested Process Steps

Time (not sequential)	Deliverable(s)
5 months	Vision and Scope
5 months	Use Cases
6 months	Functional Requirements
4 months	Structure Design Document
3 months	Implementation Plan
8 months	Stage 1 S&CPs, BPs
11 months	Implement Stage 1
	Legacy Bridge for OASIS Phase 1
	Legacy Bridge for E-Tag (including Tag Authority to IA)
	Strategic Split of IDC (Impact Calculator and TLR Process)

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Suggested Process Steps

Time (not sequential)	Deliverable(s)
8 months	Stage 2 S&CPs, BPs
14 months	Implement Stage 2
	Enhanced OASIS Functions (OP2)
	Operations Scheduling Tools (to support FM)
	Enhanced IA to Ops Sched Interface
	Enhanced Legacy Bridge (v2)
	IDC Next Generation
12 months	Stage 3 S&CPs, BPs
17 months	Implement Stage 3
	Market Scheduling
	Enhanced Market to IA Interface(v2)

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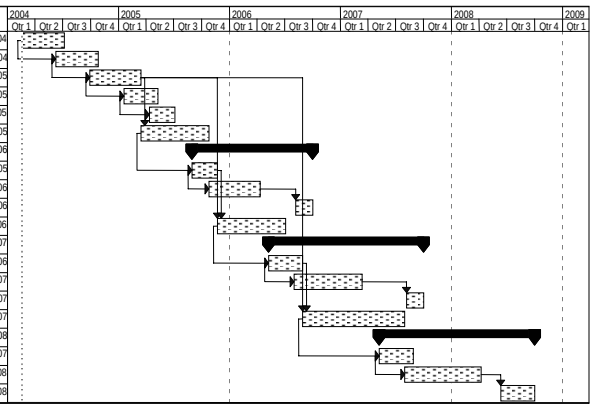
Suggested Schedule

ID	Task Name	Duration	Start	Finish
1	Vision and Scope	5 mons	Wed 2/18/04	Tue 7/6/04
2	Use Cases	5 mons	Wed 6/9/04	Tue 10/26/04
3	Functional Requirements	6 mons	Wed 9/29/04	Tue 3/15/05
4	Structure Design Document	4 mons	Wed 1/19/05	Tue 5/10/05
5	Implementation Plan	3 mons	Wed 4/13/05	Tue 7/5/05
6	Write Stage 1 S&CPs, BPs	8 mons	Wed 3/16/05	Tue 10/25/05
7	Implement Stage 1	283 days	Wed 8/31/05	Sun 10/1/06
8	Design	3 mons	Wed 8/31/05	Tue 11/22/05
9	Develop	6 mons	Wed 10/26/05	Tue 4/11/06
10	Test	2 mons	Mon 8/7/06	Sun 10/1/06
11	Write Stage 2 S&CPs, BPs	8 mons	Wed 11/23/05	Tue 7/4/06
12	Implement Stage 2	364 days	Wed 5/10/06	Mon 10/1/07
13	Design	4 mons	Wed 5/10/06	Tue 8/29/06
14	Develop	8 mons	Wed 8/2/06	Tue 3/13/07
15	Test	2 mons	Tue 8/7/07	Mon 10/1/07
16	Write Stage 3 S&CPs, BPs	12 mons	Wed 8/30/06	Tue 7/31/07
17	Implement Stage 3	366 days	Wed 5/9/07	Wed 10/1/08
18	Design	4 mons	Wed 5/9/07	Tue 8/28/07
19	Develop	9 mons	Wed 8/1/07	Tue 4/8/08
20	Test	4 mons	Thu 6/12/08	Wed 10/1/08



Note: Schedule Must Not Implement During Summer or Winter peaks

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Question

- Do we agree upon the core principles?
  - Customer-driven Development
  - Incremental Value
  - Cost Effective
  - Market Design Neutral
  - Encourage “seamless” boundaries whenever possible
  - Leverage Existing Tools without being bound by those tools

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Question

- Does everyone agree with these next steps?
  - Functional Design Work
    - Begin with the ESC Use Cases
    - Evaluate and Define OASIS functionality
  - Identify Modular Components
    - Identify key components
  - Determine Architecture
    - Group components logically based on dependencies
  - Develop Approach
    - Build implementation plan for staged approach

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Key Components

- Develop appropriate representation across the industry
- Establish “governance” issues
  - Identify leadership
  - Determine other key liaisons and roles
  - Set up meeting schedules
  - Agree to vision and scope
  - Establish milestones and deliverables

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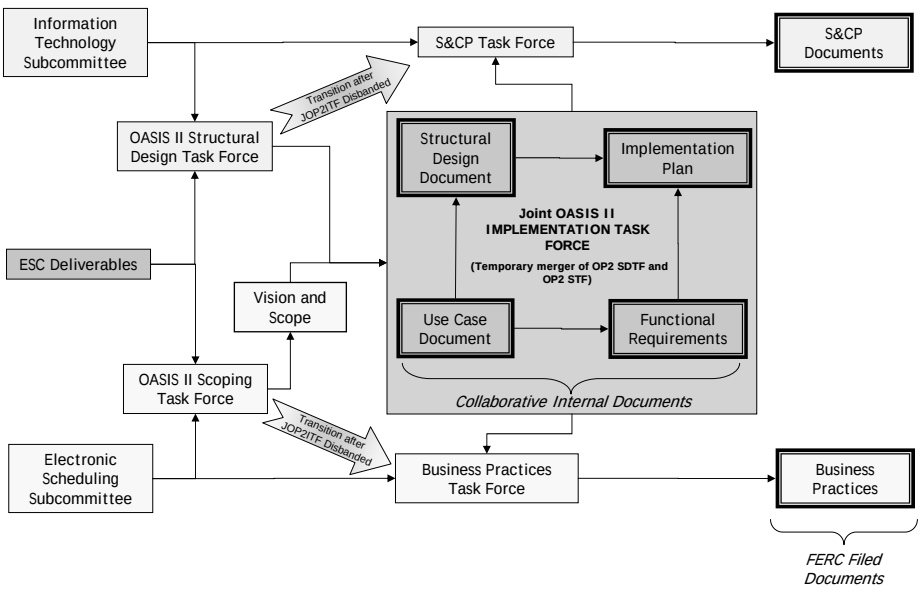

NAESB OASIS II Development Overview

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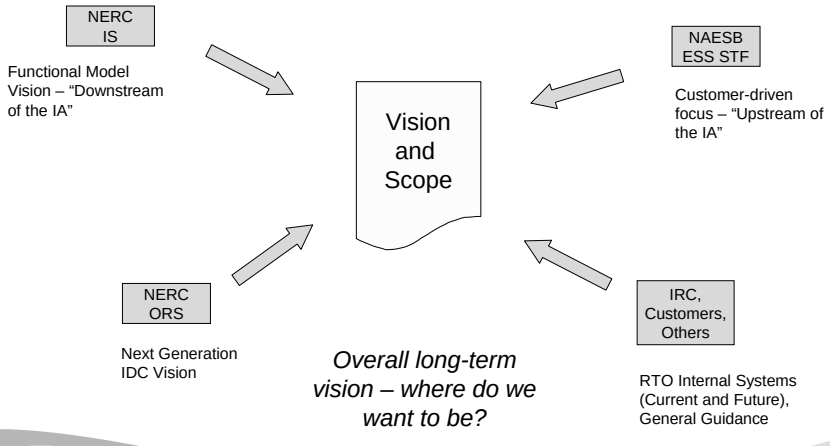
Vision and Scope



Overall long-term vision – where do we want to be?

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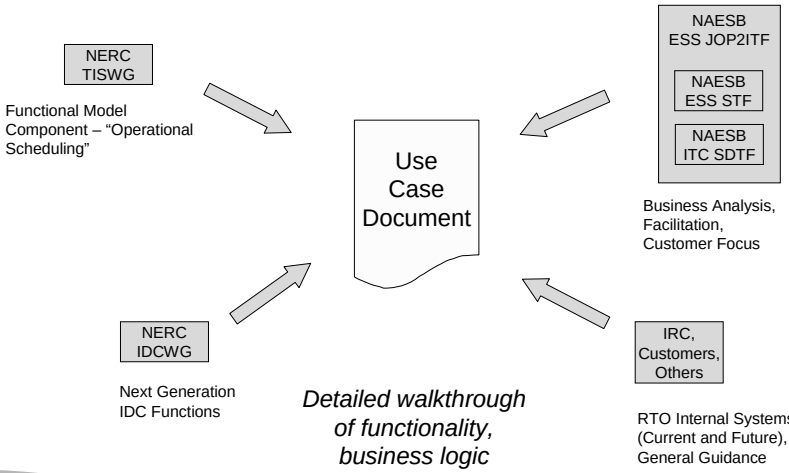
Use Case Document



Detailed walkthrough of functionality, business logic

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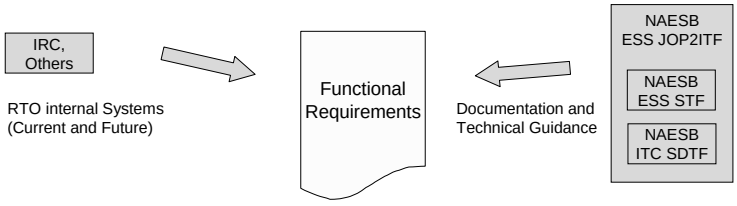
Functional Requirements



Beyond Use Cases – "blueprints" for S&CP

Includes System Requirements

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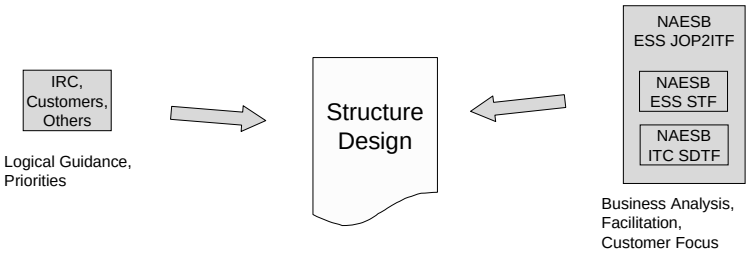
Structure Design Document



How do we want to organize the functional pieces?

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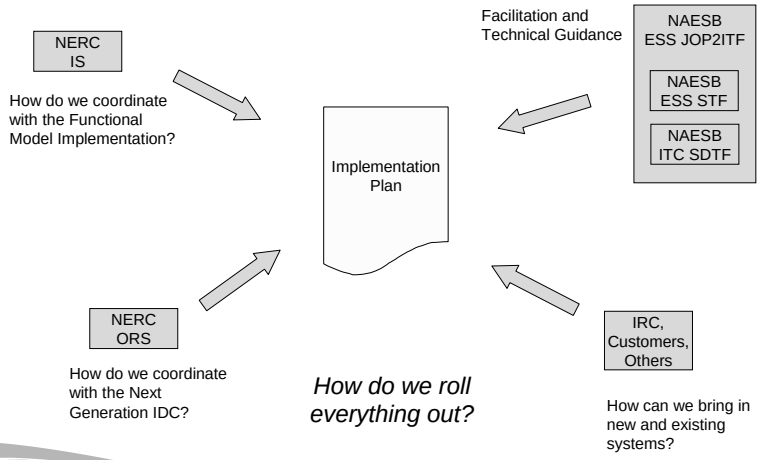
Implementation Plan



How do we roll everything out?

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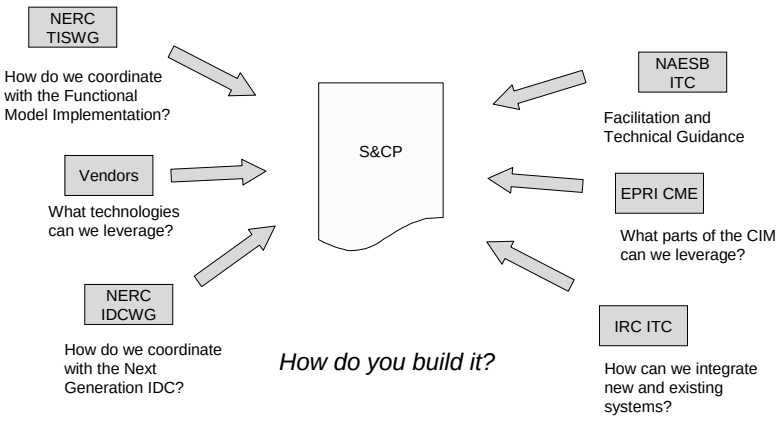
S&CP



How do you build it?

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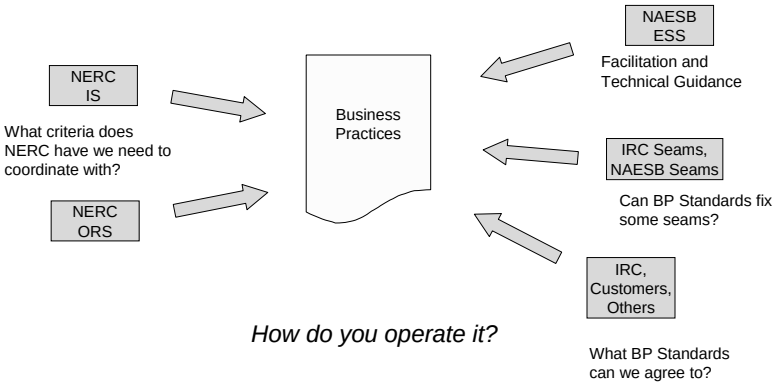
Business Practices



How do you operate it?

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Questions?

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SRS Documents

North American Energy Standards Board

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Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: naesb@naesb.org
Home Page: www.naesb.org

via email and posting

TO: NAESB WEQ Standards Review Subcommittee Participants and Interested Parties

FROM: Todd Oncken, Deputy Director

RE: Wholesale Electric Quadrant Standards Review Subcommittee Meeting Minutes – January 8, 2004

DATE: January 30, 2004

NORTH AMERICAN ENERGY STANDARDS BOARD
WEQ STANDARDS REVIEW SUBCOMMITTEE MEETING
January 8, 2004, 10:00 a.m. to 4:00 p.m. Central
Houston, TX

1. Welcome

Mr. Yeung called the meeting to order. Mr. Oncken gave the antitrust advice. Participants introduced themselves. Mr. Yeung reviewed the agenda for the meeting. On Mr. Johnson's suggestion, a review of e-MARC and PKI were added under the discussion on Cybersecurity. The draft agenda was adopted by consent.

2. Update on Transition of Coordinate Interchange Business Practices (CIBP) Task Force to the Electronic Scheduling Subcommittee

Mr. Yueng stated that as a result of a recent notational ballot, the Coordinate Interchange Business Practices (CIBP) Task Force has been reassigned to the Electronic Scheduling Subcommittee (ESS). It was noted this change reflects the transition of the CIBP from the review and scoping phase into the standards drafting phase.

Mr. Carter gave a brief review of the CIBP. He noted the CIBP continues to work closely with NERC's Coordinate Interchange (CI) Standards drafting team. Mr. Carter stated the NERC CI standard has broken the process into two parts – market and reliability – and the NAESB standard would focus on the requirements of the market period. Mr. Carter stated the CIBP is attempting to create a process that duplicates the current scheduling process in general terms. Mr. Carter said the CIBP is working to provide NERC with 4 key pieces of data to perform the reliability evaluation, but the mechanism being developed would contain more data that would be usable for different purposes. Mr. Carter said the CIBP is looking at a unified national interface to gather the data, and then processes to maintain a data format that is compatible for all industry participants. Mr. Carter said submission of the data to the Interchange Authority (IA) would likely be the transition point from market to reliability. The next CIBP meeting will be held in Dallas, TX on January 21. 2004.

Participants discussed potential issues for the SRS to monitor that were not being addressed by NERC's CI standard. Regarding the analysis of NERC's Policy 3, Mr. Carter stated that NERC's reliance on e-tag for IDC data could be an issue. Additionally, it was noted that timelines and ramping were not addressed by NERC's CI standard. Mr. Carter stated that some timelines were being considered by the CIBP, but that ramping was currently not being discussed. The SRS said a question to NERC would be whether NERC will requi4e a standard ramp rate in another NERC standard, or if NERC expects other organizations to develop standard ramp rate requirements as a business practice.

3. Report on Operate Within Limits Business Practices Task Force (OWL BP)

Mr. Yeung reported that NERC's Operate Within Limits (OWL) standard did not pass NERC's balloting body. Mr. Yeung suggested one of the problems with NERC's OWL standard was that a decision has not been made regarding the removal of system operating limits – currently TLR. Mr. Yeung noted that TLR is a very business oriented issue and it is anticipated that NAESB will develop a complementary standard to NERC's OWL standard that addresses TLR. Mr. Yeung noted there was earlier discussion of the NERC Markets Committee making a statement that NAESB should develop curtailment standards. Mr. Yeung suggested the recent events with the NERC OWL standard could provide an opportunity for the NERC drafting team and NAESB OWL-BP to work collaboratively.

Mr. Rana commented on the progress of the OWL-BP task force. He stated a review is underway to see which NERC Policies are affected by the OWL standard. Additionally, Mr. Rana said NERC staff and OWL committee members have been contacted to see whether business concerns raised during the drafting process were captured. Mr. Rana noted that document does not likely exist. Mr. Rana welcomed comments on the OWL-BP scoping document available on the SRS page of the NAESB website.

Mr. Yeung commented that NERC's Operating Committee has asked its subcommittees to do the assessment of NERC Policies. Mr. Rana added that the process began in 2001 but is not completed. He suggested there should be a push on this. Mr. Rana will contact the NERC OWL drafting team to be added to the distribution list so that he can participate in drafting team activities.

4. Initial Discussion of new NERC SARs and/or standards under development

Permanent Cybersecurity SAR: Mr. Yeung stated NERC has begun work on the permanent Cybersecurity SAR, which he understands closely tracks the urgent action standards adopted last year. Ms. Kedrowski offered to forward a document containing a compilation of the comments filed on the urgent action SAR. Mr. Yeung noted review of the permanent Cybersecurity SAR would likely surround identifying differences from the urgent action standard.

Participants briefly discussed the SAR. Mr. Johnson stated the definition of 'cyberasset' appears to be different from the urgent action standard. It was noted the definitions of other terms appear to be very specific, more so than in the previous standard. After the discussion, the following list of issues was created to help the SRS determine if a complementary standard was needed. Due to the drafting phase of the SAR, it was suggested that the compiled questions be used for SRS internal use only.

- What is the definition of logical border – ex. would the standard apply to internal software?

- Would it be possible for a NERC representative, or participant with technical expertise, to explain the proposed SAR in layman's terms?

- What implications does this SAR have for EMARC and its ultimate application – will this change the implementation timeline and will it affect business systems?

Mr. Johnson briefly discussed EMARC and PKI, noting both apply to this SAR in relation to encryption and authentication language. Mr. Johnson explained that EMARC is NERC's version of PKI implementation. It was noted the specification for EMARC has not been completed.

Assess Transmission Future Needs and Develop Transmission Plans: It was noted that this was one of the original SARs. The subcommittee felt review of the SAR was premature since a SAR drafting team has not yet been assembled. Mr. Yeung stated the subcommittee would revisit this SAR at a later time.

Participants discussed the appropriate time for the SRS to begin its review of a NERC SAR. During discussion it was noted that developing a bright-line rule was difficult, since SARs have a differing level of specificity.

Define Physical Connection Requirements: Mr. Yeung reviewed this SAR and noted it was at a very early stage. It was agreed it would be appropriate to monitor this SAR for future evaluation.

Certification Standards: Mr. Yeung briefly reviewed the history of this set of SARs, noting that drafting has begun, but the first draft is not complete. Participants briefly discussed the business implications of certification. It was noted that the work of the CIBP potentially affects the work of the Interchange Authority (IA). Participants discussed whether it was appropriate to certify the IA for knowledge of any CIBP business requirements. One suggestion was to include any business issues in the NERC certification process, so that an IA would only have to go through certification once. At a minimum, Mr. Yeung proposed to bring this to the Executive Committee's attention, since it was an issue that would impact NAESB going forward. Additionally, it was noted that, depending on the outcome of the Seams work or a potential OWL-BP standard, some Reliability Authorities (RAs) could have some commercial responsibilities. It was agreed to review the Certification Standards in more depth after the draft standards are released.

5. Continued Monitoring of previously reviewed NERC SARs and/or standards under development

Determine Facility Ratings: Mr. Yeung reminded participants that this SAR, which is the driver behind developing TTC for the industry, has been approved and is moving into the drafting stage. It was noted this standard does not address ATC. Participants expressed concern whether a standard that addresses ATC was needed, and if so, which organization should develop it. Mr. Yeung noted that the MCCTF recently addressed this question, but did not have a clear answer. Instead, he said the MCCTF referred the issue to NERC to develop an internal response. Mr. Tartibi will report on the status of this effort at the next meeting.

Balancing Resources and Demand: Mr. Vice, a member of NERC's Balancing Resources and Demand (BRD) standard drafting team, joined the meeting to discuss the BRD and address previous questions about the AOM constraints that were posed about this standard during the previous SRS meeting. Mr. Yeung noted that the SRS has previously reviewed a potential link between the BRD and NAESB's efforts on the Inadvertent Interchange Payback Task Force (IIPTF). Mr. Vice explained the framework of the draft BRD standard. He stated there are three limits on frequency: Trigger (which establishes the clock for a party to get back within limit); Frequency Abnormal Limit (which is a hard limit a party should never operate within); and Relay Limit (which will trigger the operation of under frequency relay). Mr. Vice stated these limits were viewed according to level of severity, not penalty amount. Mr. Vice noted there has been some controversy in translating from a frequency world to an ACE driven world, since there is little correlation between the two. Mr. Vice was very clear that the BRD drafting team did not want the decision to violate the standard to be based on an economic decision. Mr. Vice stated the compliance team would set penalty levels. Mr. Vice noted the specific levels have not been set yet.

Mr. Terelmes commented on the work of the IIPTF. He stated the task force has struggled with whether it was appropriate to include a factor that keyed frequency deviation to Inadvertent Interchange payback. Mr. Terelmes stated that if Inadvertent Interchange was settled without settling for the frequency, it was still important to understand the frequency of the interchange at the time of the Inadvertent Interchange, because that goes directly to the nature of the Inadvertent. Mr. Vice agreed that the financial settlement of Inadvertent Interchange does not need to directly correlate with frequency and suggested the most likely solution would be for settlement to occur only after it reaches a trigger bandwidth. Mr. Terelmes noted the IIPTF has discussed an adder calculation to push the settlement price for inadvertent interchange above the market price, and it is very tempting to use a an adder based on degree of frequency deviation. Mr. Terelmes suggested that perhaps there will be an adder not based on frequency.

It was agreed that this discussion provided sufficient information for the IIPTF to move forward.

6. Update on Coordinate Operations Business Practices (COBP) Task Force

Mr. Yeung stated NERC's Coordinate Operations standard currently being drafted. After drafting is complete, the NERC CO standard will be distributed to SRS participants for review and internal comment. Mr. McCoy will report on this issue at the next meeting.

7. New Business

The next SRS meeting was scheduled for February 25 in Houston, TX, with time TBA.

8. Adjourn

The SRS meting adjourned at 2:20 p.m. Central.

9. Meeting Attendees:

Name	Company	Notes
Scott Brown	Exelon	Phone
Roman Carter	Southern Company	Phone
Ed Davis	Entergy	Phone
Henry French	CenterPoint Energy	In Person
Alan Johnson	Mirant	Phone
Barb Kedrowski	We Energies	Phone
Steve McCoy	California ISO	Phone
Lou Oberski	Dominion	Phone
Todd Oncken	NAESB	In Person
Raj Rana	American Electric Power	Phone
Jerry Smith	Arizona Public Service Co.	In Person
Steve Terelmes	Ameren	In Person
Raymond Vice	Southern Company	Phone
Carl Williams	Exelon	Phone
Charles Yeung	Reliant	In Person

Standard Authorization Request (SAR) Form

Title of Proposed Standard:	Assess Transmission Future Needs and Develop Transmission Plans
Request Date:	March 6, 2002
Authorized for Posting:	March 20, 2002
SAR ID# :	TRNS_NDS_&_PLNS_01_01

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name:	Jim Byrd	X	New Standard
Primary Contact:	Jim Byrd		Revision to existing Standard
Telephone: Fax:	214-743-6870 972-263-6710		Withdrawal of existing Standard
e-mail:	jbyrd@txu.com		Emergency Action

Purpose/Industry Need (Provide one or two sentences)

To establish a standard for assessing and planning the transmission systems in North America.
The transmission system must be assessed and planned to ensure that it performs its intended functions in providing reliable delivery of power for the future needs of customers.

Brief Description (A few sentences or a paragraph)

Requirements shall be established for assessing transmission system performance under a variety of system conditions including system normal conditions, abnormal conditions, and extreme system conditions. Requirements shall be established for a plan, including a definition of the planning horizon, to address these conditions to ensure that the interconnected transmission systems perform their intended functions and to prevent severe adverse effects such as uncontrolled or cascading interruption of network operation. The plan may utilize operating, construction, market solutions or other components to address these conditions.

SAR: Assess Transmission Future Needs and Develop Transmission Plans

Reliability Functions

The Standard will Apply to the Following Functions *(Put an 'X' in front of each one that applies)*		
X	Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
	Interchange Authority	Authorizes valid and balanced Interchange Schedules
X	Planning Authority	Plans the bulk electric system
	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
X	Transmission Owner	Owns transmission facilities
	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer
	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

SAR: Assess Transmission Future Needs and Develop Transmission Plans

Reliability and Market Interface Principles

Applicable Reliability Principles *(Put an 'x in front of all that apply)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
	2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand
X	3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably
	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented
	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems
X	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions
X	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis

Does the proposed Standard comply with all of the following Market Interface Principles? *(Enter 'yes' or 'no')*	YES
1. Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
2. An Organization Standard shall not give any market participant an unfair competitive advantage	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

Assess Transmission Future Needs and Develop Transmission Plans

SAR Commenter Information			
Name	David H. McMillan		
Organization	Calpine		
Telephone	713-830-8710	Fax	713-830-2001
E-mail	dmcmillan@calpine.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☒ Yes ☐ No

Look at the SAR called: Assess Transmission Future Needs and Develop Transmission Plans:
Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: any aspect that goes beyond establishing specific reliability criteria to be incorporated into the Transmission Planning activity and product.
Other comments: The "Generator" reliability function should be checked as being impacted since generators are defined as an integral component of the bulk power transmission system being planned.

SAR Commenter Information			
Name	Bill Carr		
Organization	Dynegy, Inc.		
Telephone	713-7657-8723	Fax	713-767-5986
E-mail	bill.carr@dynegy.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☒ Yes ☐ No

Look at the SAR called: Assess Transmission Future Needs and Develop Transmission Plans:
Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:
Other comments: The purpose/industry need section should start with: The purpose of this standard is to ensure that a consistent, uniformly applied standard is developed .. ..

SAR Commenter Information			
Name	John Anderson and John Hughes		
Organization	Electricity Consumers Resource Council (ELCON)		
Telephone	202-682-1390	Fax	202-289-6370
E-mail	jhughes@elcon.org/janderson@elcon.org		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

The actual drafting of these 11 SARs is premature. Every "reliability" standard also is a "commercial" standard. There must be very detailed coordination with the organization that will establish "commercial" standards (NAESB). Such coordination has not even begun. The scope, procedures, process and practices of such coordination must be clearly specified and agreed to before the drafting of the SARs begins.

Look at the SAR called: Assess Transmission Future Needs and Develop Transmission Plans:
Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: The establishment of this SAR is premature. All commercial implications of the SAR should be identified and mitigated prior to the drafting.

SAR Commenter Information			
Name	Phil Park		
Organization	Powerex		
Telephone	604 891 5020	Fax	604 895 7012
E-mail	phil.park@powerex.com		

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

I have a general comment to preface my comments on the individual SARs. To me, what we are calling a "core reliability requirements" are simply technical specifications for things we believe the industry cannot adequately address through commercial negotiations between individual players or things too small to bother with by one on one negotiations. Core reliability requirements do not include business practices. These technical specification should ensure that they do not prohibit worthwhile commercial negotiations. With this definition, all core reliability requirements have commercial elements. I can accept this and this should not inhibit us from setting a technical specification (core reliability requirement) where one makes sense. However, we must avoid setting one whenever we can, simply because we can. This latter approach will inhibit valuable commercial activity. If the reliability standards become so encompassing that they threaten commercial activity, we will simply end up focusing on including exemptions, waivers, and differences such that the standard has limited applicability.

In many cases in my comments below I have not indicated whether or not the proposed standard is required. This can only be determined after we have rationalized the details of each of the SARs. The answer to this question should be an outcome of the process, not an input to it.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate: The description should be revised as follows:

"Requirements shall be established to ensure that interconnected transmission systems are planned such that they can reliably perform their intended functions over a wide range of system conditions." The phase "while continuing to operate reliably within equipment and electric system thermal, voltage, and statbility limits" should be transferred to SAR #2 addressing facility ratings, operating limits, and transfer capabilities.

Other comments: *Assessment of future needs and development of transmission plans is highly related to commercial processes. As in other markets, information needs to be collected to assess future ability of the market participants to respond to market requirements. This SAR should be coordinated with business practices for the industry.*

The phase I am recommending be moved to SAR #2, which appears to encompass standards presently covered by Planning Standards I.A (Table 1) and I.D, is the major component that makes this SAR a core reliability requirement. My rationale for moving this to SAR #2 is included in the comment form for that SAR.

SAR Commenter Information			
Name	MAAC Region		
Organization	MAAC		
Telephone	610-666-8854	Fax	610-666-2297
E-mail	dicapram@pjm.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

MAAC questions the need for standards concerning 'Design' of Protection systems, Physical connection, Coordinate Interchange, and Analysis of disturbances.

"Design" issues are commercial issues not reliability issues.
The Transmission Operators will define Interconnection Agreements.
Coordination of Interchange can be a subset of "Coordinate Operations"
Disturbance analysis will be address by regulators

Most of these are good business practices or good utility practice but not core reliability standards.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments:

The substance of this SAR should focus on defining 'uniform study conditions' and on ensuring that all interregional analyses use those conditions.

Must ensure that the SAR does NOT become a mandate "to use the same load flow Tool" (which would be a violation of the Market principles).

SAR Commenter Information			
Name	Mike Miller		
Organization	Southern Company		
Telephone	205 257 7755	Fax	6663
E-mail	mbmiller@southernco.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The "Assess Transmission future needs and develop transmission plans" SAR does not state a requirement to plan the system so that it can be operated within operating limits. I feel that this terminology (operating limits or other term such as Operating Security Limits) should be common among all SARs. The system must be planned so that it can be operated reliably. Using this terminology in all SARs would provide the appropriate link among them.

Without knowing the details that will be included in the standards as described by these SARs, it is difficult to make an assessment on the completeness of this set of SARs. I feel that there should be a SAR that requires LSEs, distribution providers, and generators to respond to requests that will have the effect of operating the system within Operating Limits.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: Planning must be coordinated to optimize not only transmission but generation as well. The left alone process of disjointing generation and transmission is creating a non-steady state electrical system. The criteria for designing a system must include defined measurements adopted by all. This brief description does not provide sufficient detail to ensure reliability is planned. The planning criteria must address defined transmission planning for transfer usage as well as specific load service usage in other words interconnection as well as intraconnection. The need to define roles, responsibilities and authority must be developed between Federal (RTO) characteristics and functions and transmission owners.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Transmission Operator and perhaps Distribution Provider should be added to the list of applicable functions.

SAR Commenter Information			
Name	Alan Johnson		
Organization	Mirant Americas Energy Marketing		
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E-mail	alan.r.johnson@mirant.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

There may not be a need for the following two standards: i) Define (Physical) Connection Requirements; and ii) Monitor and Analyze Disturbances, Events, and Conditions.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: Reference to standardization of the solution set for the transmission plan (see Brief Description section). Mirant is concerned that the standard goes beyond assessment and planning of the bulk transmission system, delving into definition of the methods for meeting the plan. Per the *Market Interface Principles* (principle 4), the standard should not inhibit commercial/market solutions.

Other comments:

Mirant believes that the standard should not apply to the Transmission Owner function, consistent with the *Functional Model*.

April 23, 2002

SRP Comments on NERC 11 SAR sent out on April 2, 2002.

All 11 SAR's (this group of 10 plus the one sent out earlier) don't contain enough information to make the kind of judgments requested on the forms. Therefore the forms are not filled out.

We recommend all the SAR's be advanced to the next step to develop the specific standards and associated measurements for each standard so that we can evaluate and comment on them.

All of these SAR's are needed for reliable planning and operation of the bulk electric transmission system and meet the principle requirements.

Comments on the White paper:

1. The paper fails to state what standards are supposed to be. This seems so basic; one has to assume that those drafting the white paper want to redefine the definition contained in the Organizational Standards Manual. This leads to a lot of confusion and is not the place to do that.

2. The Planning Standards were written in a different time period than the Operating Policies with different objectives. Thus they are different and that should be recognized. For instance the development of a Planning Functional model has absolutely nothing to do with whether control areas exist or not and whether companies have restructured or not. The statement about control areas may be true for the Operating Policies but it is not try for the Planning Standards.

   The Planning Standards (Templates) were written to meet the definition of a standard in the Organizational Standards Manual, to meet at least one of the Reliability Principles, to comply with all the Market Interface Principles and to contain the compliance administration elements. This is very different than what is contained in the Operating Policies. The Planning Standards need to go through the new process so that both the Operating elements and Planning elements of the Organizational Standards are consistent, are not duplicative and are needed for reliability.

3. The term " core reliability requirement" is used in the white paper but is never mentioned in the Organizational Standards Manual. Using an undefined term is very misleading and should be avoided.

4. The paper in several places address "what performance must be achieved". As noted above, an Organizational Standard can be broader than that and this write up is misleading.

5. The process has been lengthened because of the multiple posting of the SAR's. NERC has a body of reliability requirements written up into Compliance Templates. With very little effort these could be written up into SAR's that would provide sufficient detail for NERC to evaluate them. It is very hard to comprehend why one does not use this work to expedite the process. Instead SAR's are sent out with insufficient information. The process is long enough. We should be looking for all ways possible to speed it up.

Comments on the SAR write-up:

1. The SAR write-up only contains the purpose and brief description of a standard. Where is the Standard? I thought that is what the SAR is for?

2. The descriptions are in most cases extremely vague. The write-ups contain words like "such as" or "as defined in the standard". These are big enough to cover a MAC truck. Once again there is insufficient information to make a good judgment.

April 29, 2002

Guy V. Zito
Manager, Planning
Northeast Power Coordinating Council
1515 Broadway Floor 43
New York, NY 10036

RE: NEPOOL Compliance Working Group (NCWG) comments pertaining to the 10 Standard Authorization Requests (SARs) posted for open comment

The NCWG has reviewed the 10 SARs posted for open comment and has agreed they are core standards, which serve a purpose in support of reliability.

Standard Title:
Prepare for and Respond to Abnormal or Emergency Conditions
Prepare for and Respond to Blackout or Island Conditions
Coordinate Interchange
Coordinate Operations
Monitor and Analyze Disturbances, Events and Conditions
Operate Within Limits – Monitor and Assess Short-term Transmission
Define (Physical) Connection Requirements
Design, Install, and Coordinate Control Protection Systems
Assess Transmission Future Needs and Develop Transmission Plans
Determine Facility Ratings, Operating Limits, and Transfer Capabilities

We do not agree that the **SAR Type** is a new standard. We suggest that at a minimum the SAR should indicate the existing standard and whether or not it will be withdrawn when the revised standard is adopted. We suggest that NERC stop the open process of reviewing existing policies and standards if these Organizational Standards will replace them. NERC should clearly indicate that one purpose of the Organizational Standards Process is to replace existing standards.

Sincerely,
Daniel L. Stosick

Chairman, NEPOOL Compliance Working Group
C/o ISO New England, Inc.
One Sullivan Road
Holyoke MA 01040-2841

Cc: NEPOOL Compliance Working Group
CP9 Working Group
Paul Shortly
Richard Burke
Richard Kowalski

SAR Commenter Information			
Name	Robert D. Smith		
Organization	Arizona Public Service		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: We do not believe that transmission plans should utilize market solutions as solutions to identify problems.

SAR Commenter Information			
Name	Mr. Charles Moser (Northborough, MA) and Mr. Ronald Halsey (Syracuse, NY)		
Organization	National Grid USA		
Telephone	508 421 7600 315 428 3181	Fax	508 421 7520 315 428 5615
E-mail	charles.moser@us.ngrid.com ronald.halsey@us.ngrid.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: These standards as written delve much too deeply into the details of "HOW" and "WHAT" AND "WHEN". They instead should stick to the idea of developing an umbrella of BROAD PERFORMANCE BASED CRITERIA standards that establish the basis for the creation of Region specific standards that will meet the intent of the NERC standard.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate:

Other comments: The standard should define the transmission system performance basis upon which any planning or assessment efforts would be measured. We do not need a standard on HOW to assess or plan our systems. We need a broad based standard that will define the required transmission system performance levels based on an established and demonstrated need for such performance levels rather than on an abstract concept of "reliability".

SAR Commenter Information			
Name	Vern Colbert		
Organization	Dominion Virginia Power		
Telephone	(804) 273-3399	Fax	(804) 273-2405
E-mail	vern_colbert@dom.com		
Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☒ Yes ☐ No			

SAR Commenter Information			
Name	Greg Gideon		
Organization	TXU Energy		
Telephone	214-875-9483	Fax	214-875-9246
e-mail	ggideon1@txu.com		
Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☒ Yes ☐ No			

SAR Commenter Information			
Name	Paul Rocha		
Organization	Reliant Energy HL&P		
Telephone	713-207-2768	Fax	713-207-2281
e-mail	paul-rocha@reliantenergy.com		

Reliant Energy HL&P ("HL&P") files these comments regarding the ten Standard Authorization Requests (SARs) discussed below. Please note that HL&P is the regulated electric utility operating in and around the area of Houston, Texas, within the ERCOT region. HL&P does not represent Reliant Resources, the unregulated energy services company operating in various areas of North America and Europe. Reliant Energy expects to spin off Reliant Resources later this year. In anticipation of the pending separation, HL&P and Reliant Resources are operating in large part as two separate companies. It is HL&P's understanding that Reliant Resources may separately provide comments regarding these SARs.

HL&P agrees that there is a need for a standard for assessing transmission future needs and developing transmission plans. We support ERCOT's comments, which either have or will soon be filed, regarding the appropriate scope and characteristics of such standards. However, we believe a prospective NERC planning standard should apply to interstate and international electric systems only, and should not apply to intrastate electric systems such as ERCOT, as explained more fully below.

The assessment of need and development of transmission plans should strive for an appropriate balance between ensuring reliability, maintaining reasonable transmission rates, mitigating congestion costs, and avoiding unnecessary landowner impact. For intrastate transmission systems such as ERCOT, HL&P believes that the appropriate place to balance these objectives is within the intrastate region itself, since the ERCOT organization, and the standards it develops, are subject to state commission review and approval. That same state commission (the Public Utility Commission of Texas) also has rate-setting and line certification authority, and thus is uniquely positioned to balance the conflicting objectives involved in transmission system planning. However, for interstate and international regions, it may be appropriate for NERC to develop a transmission planning standard. Recognizing that NERC does not have rate-setting or line certification authority, NERC should guard against establishing one-dimensional standards that fail to take into account all the dimensions that guide the transmission planning process.

SAR Commenter Information			
Name	Brant Eldridge		
Organization	ECAR		
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ECAR has conducted a survey of its member companies regarding the eleven SARs, which NERC has initiated to-date. We recognize that the comment period for the first SAR issued ("Balance Resources and Demand") has already closed. However, considering that the first SAR was issued earlier than the other ten primarily just to get the process started, and further considering that all 11 SARs are viewed by NERC as a possible complete set of Organization Standards (re: the "White Paper"), ECAR believes that comments on the first SAR should still be considered along with those on the other ten.

11 of the 18 ECAR Full Members, along with two Associate Members, submitted responses to the SAR survey. Some of the responses were submitted using the NERC "SAR Comment Form", while others were contained in narrative e-mails, and one was faxed to us. Therefore, a complete set of the ECAR member company responses will be sent to the Standards Process Manager at NERC via Fed Ex to arrive at NERC by May 3rd. The Fed Ex package will include a copy of this e-mail. FYI, NERC may also receive some of the ECAR member company responses directly from the companies. Some of the individual company responses will be identical to what will be in the Fed Ex package and some will contain more detailed comments.

The ECAR member company responses contain numerous and wide-ranging comments about the need for each of the 11 proposed Organization Standards, as well as comments regarding the scope and applicability of the SARs. As your review of these responses will show, there is general ECAR consensus – but not unanimity -- that the 11 SARs as a set cover the scope of performance needed to ensure reliability of the interconnected North American bulk power systems. Some ECAR members feel that there are performance areas not covered in the proposed set of Organization Standards, and they have provided what they think is missing. Others believe that some of the proposed Organization Standards are not needed, and they explain why they feel that way. Numerous comments were directed at the scope and applicability of the SARs. Several ECAR companies questioned the inclusion of the "Distribution Provider" function in the applicability section of the SARs, believing that NERC should stick to its traditional focus on the bulk power systems and stay out of the distribution arena.

The recent call for nominees to serve on SAR Drafting Teams is the appropriate next step. ECAR believes that all 11 SARs need to be refined to reflect industry comments and then posted again for another round of industry comments. Before proceeding into actual development of Organization Standards based on these 11 SARs, NERC must have clear industry consensus on the need for each of the Organization Standards outlined in the 11 SARs, as well as consensus on the scope and applicability of those SARs.

If the wide-ranging comments received from ECAR members are any indication, there is still some serious work to be done to achieve the needed clear industry consensus on how to proceed.

East Kentucky Power Cooperative (General Comment)

EKPC believes our present standards are adequate and therefore is not in favor of developing a new set of standards. We also believe the new process should be revised to provide for a screening committee to evaluate proposed standards before they are presented to all NERC members for comment. However, given that we are going to develop new standards with this process, EKPC endorses all eleven of the SARs. Thanks, Paul Atchison.

LG&E Energy (General Comment)

LG&E agrees there is a need for the eleven proposed organization standards. However, we do see a disconnect with their development and operating procedures/protocols of RTO's. Where will this coordination take place to ensure consistency, eliminate redundancy, and application particularly since there will most likely be more than 1 RTO at the time of issuance?

VECTRON - Southern Indiana Gas & Electric (General Comment)

The NERC Proposed Organization Standards appear to me to cover the scope of performance needed to insure reliability of the interconnected grid. The scope of the SARs as proposed, also, look fine to me.

Dayton Power & Light (General Comment)

We are okay with the 11 proposed Standards.

American Electric Power (General Comment)

BERNIE M PASTERNACK
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Company: AMERICAN ELECTRIC POWER
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825 TECH CENTER DR
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American Electric Power is providing the following comments on the 10 most recent Standard Authorization Requests (SARs) to ECAR as input to the formulation of ECAR's response to NERC. AEP looks forward to working with ECAR and NERC as well as other market participants to ensure the continued reliability of the electrical system.

Clearly the electricity industry has been exceptionally dynamic and fluid in recent years and is going through many changes. While changes can be positive, it is incumbent on the industry to ensure that changes, which are adopted result in enhanced reliability and a better market environment. With this in mind, we envision that there are actually three interrelated but separable processes with respect to the development of standards.

First, the relevant standards need to be identified. Over recent months this has been referred to as defining "what" the standard is.

Second, there need to be decisions about "how" these standards are to be achieved.

Third, choices have to be made as to how these standards will be implemented.

The resultant standards, when implemented and operational, will potentially affect production, consumption and investment decisions. By necessity, the standards, including how they are achieved and implemented, are closely related to the design of the market and the separation of functions among market

participants and service providers. For this reason, we encourage discussion and even preliminary definition of what core reliability standards are needed. However, we strongly urge restraint with respect to the other two aspects of the process - defining how the standards will be achieved as well as how they will be implemented. In our opinion, the latter two processes are highly integrated with the process of market design and implementation as well as market operation; the development of RTOs; and the definition of the NERC/NAESB interface.

Given that closure on many of the market design issues is expected in the near future, we see little risk in delaying the latter two processes - how the standards are achieved and implemented-- until such time as clarity is achieved on Standard Market Design (SMD) and RTO formation. Moreover, since the NERC/NAESB interface will likely impact decisions on how standards will be achieved as well as how they will be implemented, it seems logical to wait until that interface has been defined.

We think it would be beneficial for NERC to recognize that nothing is gained by deciding how the standards will be achieved (including implementation) at this stage of the debate on Standard Market Design and the RTO development process. We would prefer to see the SAR process simply make the threshold determination as to whether any of the proposed standards are needed, and then put on hold the actual development of those standards that are needed until the critical market development activities described above are closer to completion. AEP is reviewing the SARs with particular emphasis on their scope, both individually and collectively, and we plan to provide appropriate comments to NERC by May 3.

Consumers Energy (General Comment)

Consumers Energy opposes all 10 of the SARs on their present form. We understand that it is too late to vote on the 11th SAR.

The concern that we have is that there is only limited ability to prevent new requirements from being incorporated with the old, standard reliability requirements. The SAR descriptions sound good because they espouse the old, tried and true reliability concepts that we have known and loved from the past. If there was an effective way to limit the resulting practices to those traditional values, I would be the first to support them. Unfortunately, we are not voting here on codification of the current practices. We, instead, are voting to develop a set of practices that will include the currently unknown and possibly oppressive, unacceptable set of future requirements. This vote has nothing to do with the tried and true practices from the past. Its about accepting an unknown set of requirements on faith and trust ... that none of the practice developers will be out to do us harm.

The standard argument here is that the SARs are only scope setting documents and that we will still have a change to shape and to vote on the actual standards when they go through the final approval stage. If we believe this argument, we are totally ignoring the lessons from the past. There is no guarantee that ECAR will have any personnel involved in the development of the final practices. It is unclear how many people will be involved in the drafting of the practices nor how they will be selected.

The biggest single concern is what the final product will look like and how it will be voted on. I would make a modest wager that it will consist of a handful of standard practices that we all could accept (and in fact would insist upon) along with three practices that are new and totally unacceptable. We will be faced with the proposition that we must vote on the "package" of practices where we must accept the bad ones to get the good ones. I can find no reference to a line item voting procedure.

The solution to this problem is to suggest a provision in all ten SARs that the final package of practices will not include any policies that are not already in the NERC approved set of policies and standards. Consumers Energy could then support all ten SARs.

C.V. Waits

Duquesne Light Company (General Comment)

OPERATIONS AND ASSET MANAGEMENT
System Operations
Transmission Business

TO: Brant Eldridge
FROM: J. F. Rosser
DATE: May 8, 2002
SUBJECT: NERC "Organizational Standards"

In response to your memo of April 19, 2002, Duquesne Light Company presents the following comments concerning the eleven "Standard Authorization Request" (SAR) Forms. Generally, the proposed standards seem to simply restate today's standards and label them as "new" Organizational Standards. Specifically, the proposed SAR titled "Balance Resources and Demand" is really a restatement of the current Disturbance Control Measure, CPS1, CPS2 and a new Frequency Response Measurement. This SAR, as represented at the CRC meeting, was to provide an example of how other SARs should be composed.

1. The purpose of the standard is stated as; Maintain scheduled Frequency within an Interconnection.

2. The Industry need includes Arrest Sudden frequency changes; Prevent Time error; Prevent Operation of Underfrequency Relays, prevent line loading limits violations, minimize inadvertant interchange.

3. Standards include; a measurement (FRM) to ensure automatic throttle controls are available to arrest frequency changes, a measurement (CPM1) to ensure adequate generation control regulation to maintain scheduled frequency, a measurement (CPM2) to ensure unscheduled power flows do not occur which could cause transmission operating limit violations, a measurement (DCM) to ensure scheduled frequency is maintained after a disturbance.

It is evident that this SAR's Title, Purpose, Need and Measures are inconsistent with each other, mixing frequency schedules and inadvertant accumulations with transmission loading violations and time error. Also, certain "Needs" and "Standards" are inconsistent with the NERC BOT decision to not pursue the development of business practices (i.e., minimization of inadvertant accumulations, timer error accumulations, etc. are equity issues and not related to reliability concerns).

Furthermore, suggested are measures that better relate to other Standards. For example, transmission limit violations fit better into "Monitor and Assess Short Term Transmission Reliability" – operate within limits. When considered under that alternate standard, this measurement may not survive because other measurements may be deemed more appropriate.

Look at the SAR from a purely technical approach. In doing so, Duquesne Light suggests that the title of the Standard "Balance Resources and Load" should be rewritten to be "Maintain Scheduled Frequency".

The Purpose of Standards would be to maintain Interconnection frequency within acceptable limits.

The Industry Need would be to prevent damage to customer equipment and to prevent unstable operations related to disturbances.

The Standard should include a description of acceptable frequency along with a technical defense of the standard including standard generator limits, motor limits, etc.. See ECAR Document #3, Appendix 1, (attached) as an example.

The Standard should include adherence to accepted industry practices such as the installation of underfrequency relays, automatic governor control requirements, etc. including the operation of this equipment within limits specified within the standard.

Measures and Requirements may include:

1. a measurement similar to CPS1
2. annual audit of underfrequency load shedding equipment, levels, and set points
3. annual audit of the status and condition of automatic governor controls
4. monitoring of frequency excursions related to disturbance conditions (Security Coordinator)
5. Coordination of interchange schedules

Measurements should not include:

1. DCM because it duplicates CPM1 and is not frequency sensitive
2. CPM2 because it purports to protect against transmission loading violations related to SAR #6

If NERC would consider business practices, the ECAR Inadvertant Settlement Process could be incorporated into the standard with a longer range target of replacing energy banks with a pay as you go policy, possible tied to adders ($/MWH) related to system frequency deviations from schedule. Otherwise, NAESB would develop these business practices.

The following are Duquesne's comments on the other 10 proposed SARs.

1. Assess Transmission Future Needs & Develop Transmission Plans – Appropriate
2. Determine Facility Ratings, Operating Limits and Transfer Capabilities – Appropriate
3. Design, Install, Coordinate Control and Protection Systems – Appropriate
   Standard should be expanded to include coordination between Transmission Owners, Transmission Operators, etc.
4. Define (Physical) Connection Requirements – Inappropriate as a stand alone SAR
   This SAR should be included in SARs #2, #3, #6, #7, #8, #9, #10, #11
5. Previously reviewed
6. Operate Within Limits – Monitor & Assess – Inappropriate as a stand alone SAR, but should be incorporated with SAR #8. Coordinated operations are required to ensure limits are not violated.
7. Coordinate Interchange – Inappropriate as a stand alone SAR. Should be part of SAR #5.
8. See review of SAR #6.

9., 10., and 11. Should be incorporated into SAR #6/#8 and/or #5 as modified by DLC

In conclusion, Duquesne Light applauds the NERC SAR initiative. NERC must, however, take care to not simply allow this initiative to be a restatement of existing standards

and application of performance measurements that miss the target. Care must be taken to identify the exact technical need/purpose (quantifiable) for each performance standard, ensuring that each performance measurement ties precisely with a stated need/purpose in support of the standard (e.g., A Standard whose purpose is to maintain frequency should not be tied to a need to limit unscheduled power flows that can cause operating limit violations but should be tied to general turbine-generator requirements).

cc: ECAR Executive Board
ECAR Coordination Review Committee
ECAR Market Interface Committee

SAR Commenter Information			
Name	David L. Hart		
Organization	Ohio Valley Electric Corporation		
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E-mail	dlhart3@aep.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The SAR seems broad enough to enable it to include planning associated with IPPs. This should definitely be considered in the further development of this Standard.

SAR Commenter Information			
Name	Lew Gray, Mike Holtsclaw, Steve Clouse		
Organization	Indianapolis Power & Light		
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E-mail	lew.gray@aes.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

What is missing from the NERC set of SARs?

1. Load forecasting, generation capacity, and capacity margin analysis.
2. Generation operating requirements:
    a. Voltage schedule produced and followed
    b. Voltage control kept on automatic
    c. Generator controls with a 5% or less droop
    d. Speed control (frequency) on automatic
    e. Record the times and reasons when speed control, voltage control, or voltage schedule were not on automatic.
3. Reliable construction and maintenance standards for transmission lines, transmission substations, and generation substations.
4. Control Area tie-line tripping for conditions of:
    a. Under frequency
    b. Overload
    c. Instability
    d. Voltage collapse

    Note that item #4 was not included in the old NERC Reliability Standards. We did not have the technical ability to properly manage these conditions for at least the first twenty years of NERC. We now have the technical ability to predict and operate at the **points of no recovery** for these conditions and should not do so, to:
    a. Reduce the number of **Control Areas Blacked Out** by a major disturbance to the interconnected grid.
    b. Make **Safe Unit Shut Down Power** from neighboring control areas much more available.
    c. Make **Unit Restart Power** much more available from neighboring control areas.
    d. Make **Load Restoration Power** much more available from neighboring control areas.
    e. **Reduce Dependence** on questionable black start plans.
    f. **Never disconnect a control area** from the interconnected grid, unnecessarily.

All that is needed at this time for this item #4 is that the five ECAR technical panels involved (OP, TSPP, TFP, GFP, PP) develop a set of guides for these four conditions for which tie lines should be tripped. Then, any control area that would like to obtain the six advantages listed above, would have a solid well thought out set of guides to start from. (I would be glad to help any of the technical panels with the details. Lew Gray)

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	David W. Sandefur		
Organization	Hoosier Energy REC, Inc.		
Telephone	812-876-0267	Fax	812-876-3139
E-mail	dsandefur@hepn.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

Other comments: The Standard should also apply to the Transmission Provider function since the source fo much of the congestion management/ TLR related data will be obtained from this functional area.

SAR Commenter Information			
Name	Verne B. Ingersoll, II		
Organization	Progress Energy - Carolina Power & Light Company and Florida Power Corp.		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

General Comments:

1) Even though the Standards drafting committee is to be fairly small (8 or 9, I believe), there needs to be a committee VOTING process for deciding on the final proposed wording or a Standard.

2) There needs to be a formal face to face forum for reviewing SARs after the drafting committee has done its work. Some have proposed the current Standing Committee meeting as this forum. As long as the meetings match up with the Standards development timeline, this would be OK.

3) We also support the submittal of the actual Standards Development process through the SAR process. The current process was developed without any "due process" or formal approval process prior to the BOT adoption.

4) We still believe that there are too many Segments in the NERC process.

5) The new NERC standards development should be completed and receive ANSI approval before development begins on the new standards contemplated by these SARS. Proceeding with SARS before the new standards process is in place ensures that significant re-work will be required.

6) The industry is already stretched very thin supporting the many NERC and FERC initiatives. The number of SARs proposed at one time is excessive. Also, there will be inevitable overlaps and conflicts between the various SAR drafting groups. Only 1 or 2 SARs should move forward at one time.

7) The time provided to review and comment on such a large number of SARs was insufficient to do a thorough review and provide accurate and complete comments.

The "Assess Transmission future needs and develop transmission plans" SAR does not state a requirement to plan the system so that it can be operated within operating limits. We feel that this terminology (operating limits or other term such as Operating Security Limits) should be common among all SARs. The system must be planned so that it can be opearated reliably. Using this terminology in all SARs would provide the appropriate link among them.

Without knowing the details that will be included in the standards as described by these SARs, it is difficult to make an assessment on the completeness of this set of SARs. We feel that there should be a SAR that requires LSEs, distribution providers, and generators to respond to requests that will have the effect of operating the system within Operating Limits.

Maintenance requirements should cover transmission equipment other than just protection and control equipment.

A lot of vital requirements of existing policies are not included in any of the proposed SARS, i.e., time error correction, inadvertent, etc.

The main power equipment design, installation, and maintenance requirements are not adequately addressed in these SARs (i.e. circuit breakers, transformers, transmission lines, etc.). Should also address transmission line right-of-way maintenance.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

It appears that some of the SARS overlap and cover some of the same areas, such as "Prepare For and Respond to Emergency Conditions", "Prepare for and Respjond to Blackout or Island conditions", and "Monitor and Analyze Disturbances, Events, and Conditions". These could all fall under a single Emergency Operations SAR. "Coordinate Interchange" should also fall under "Coordinate Operations". In addition, the SARS are intended to define standards for core reliability functions, i.e., "who to do". Some of the SARS really describe processes (i.e., "how to do it") rather than define standards, such as the SAR on "Determine Facility Ratings, Operating Limits and Transfer Limits". There are others that may need to be combined-it is suggested that a remapping of policies to specific SARS should be done.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: For the Applicable Functions, TSP, T-owner, and T-operator could all apply. We question whether RA should be applicable. Was the RA inclusion possibly a holdover from when the Planning Authority was not developed?

The scope of this SAR seems rather large, perhaps it could be divided into more manageable pieces.

SAR Commenter Information		
Name	Charles Yeung	
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E-mail	cyeung@reliant.com	

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: Core organization standards for reliability must be specific and offer measurable boundary conditions to achieve reliability objectives. Additionally, these standards should not presume that procedural requirements to achieve reliability objectives are included as part of a core reliability standard. Procedures may be necessary for entities to follow to meet NERC Organization Standards requirements. Most procedures meant to achieve reliability objectives contain impacts on the operations of the marketplace. The inextricable link between the reliability needs and the market needs makes the development of reliability-driven procedures impossible to do in a NERC reliability - focused process. If NERC proceeds to develop the core organization standards for reliability, there must be close coordination with entities, such as NAESB and RTOs, that will develop market-driven procedures so that a proper procedure can be developed to meet both reliability objectives and commercial needs.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: any reference to criteria to be determined by boundary conditions established outside a measurable or quantifiable standard. A core standard for reliability should be specific and measurable. This SAR proposes that a standard be "a plan" that encompasses normal, abnormal, and extreme system conditions and not define what those conditions are. The plan is a solution - not a measurable standard. As stated in the SAR, "..the plan may utilize operating, construction, and market solutions..", there are numerous possible methods to facilitate the reliability need this SAR suggests. These methods revolve around market operations and should be developed in a process that considers all market interests and weigh those against a measurable reliability need. The proposed standard should be focused on the measurable and definable boundary conditions for "normal, abnormal, and extreme system conditions."

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

The proposed set of 11 Standards are described in very generic terms with few details. Therefore it is not possible to assess whether or not the set of these 11 organization standards is complete with respect to some or all areas of power system performance from reliability perspective. For example, there should be a standard for Power System Model (power flow, short circuit, dynamics, EMTP) Development along with corresponding Data Verification requirements. Is model building and data verification encompassed by the presently proposed set of standards? If so, there should be a separate stand-alone standard for it, because most, if not all, reliability and marketing decisions for performance and use of the transmission system are based on the analyses using this data. Providing timely, verified, and appropriate data should be the responsibility of all the users of the transmission system.

There also should be a standard for wide-area coordinated system planning. Is wide-area coordinated planning addressed by the proposed standards? While some level of coordination in planning and operation exists today, this level of coordination needs to be increased. Again, an RTO should facilitate coordination among its members and neighbors, but a standard for wide-area (beyond the boundaries of transmission owning entity, RRO, or RTO) planning would ensure that it is done on a regular and consistent basis.

Much effort (several man-years) was expended in the recent development of the NERC Planning Standards. It would seem that the main emphasis of those standards is still relevant. While we are not sure whether or not or how those standards would be used in this SAR process, we believe that at the very least, they should be used as starting points from which new standards can be developed that can wrap around the NERC Functional Model.

Not being involved in this process from the beginning, I am not sure what was considered in determining which existing standards belong in the proposed set of 11 as a separate standard. It would appear that Coordinate Interchange (SAR#7) and Coordinate Operations (SAR#8) could be combined into one Organizational Standard as could Prepare for and Respond to Abnormal or Emergency Conditions (SAR# 10) and Prepare for and Respond to Blackout or Island Conditions (SAR#11). Similarly, it appears that the proposed SAR#2, Determine Facility Ratings, Operating Limits, and Transfer Capabilities should be separated into three SARs.

Either in these Standards or The NERC Functional Model, a clear definition of who is ultimately responsible for compliance with the standard is required. For example, which entity assumes the ultimate responsibility for long term system planning? Is it ISO, RTO, ITC, Transmission Owner or Transmission Provider? As the function definition of the Planning Authority has not been defined yet, it is not certain that it would provide an answer to this question. In any case, responsible entities should be very clearly defined for compliance with each proposed standard or the new standards.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: More details to judge whether or not all reliability related activities are covered or not.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The purpose and description is too general. This standard may require to be split into two or more SARs.

SAR Commenter Information			
Name	Dan Wheeler		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☒ Yes ☐ No			
Is there a reliability-related need for an Organization Standard to be developed on this topic? ☒ Yes ☐ No ☒ Yes ☐ No The scope of the SAR is fine as it is			

SAR Commenter Information			
Name	John K. Loftis, Jr.		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: This high level SAR is ok, as is. More detail must be added in future SAR iterations/postings to provide expectations to those entities/individuals involved with planning and/or assessing the performance of the bulk power transmission system under varying conditions.

SAR Commenter Information			
Name	Terri Grabiak		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The SARs do not seem to address requirements for data (network models, generator and load models) needed for static and dynamic studies in the Operating and Planning horizones.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The sentences that refer to 'plan' to 'address these conditions' should be modified to incorporate the following concept;

When studies show that the system may not meet the performance requirements established for various conditions, plans shall be developed to address such situations, and studies shall demonstrate that when the plans are implemented the system will meet the established performance requirements.

SAR Commenter Information		
Name	George Bartlett	
Organization	Entergy Services	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

N/A

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

Entergy believes there are three "core reliability" Organization Standards needed that constitute "what" is needed for reliability:

1) Balance Resources and Demand,
2) Operate Within Thermal, Voltage and Stability Limits, and
3) Coordinate Operations.

All the other eight SARs, including other processes like TLR, constitute "how" these three "core reliability" Organization Standards are met. The remaining eight SARs do not rise to the level of "core reliability" Organization Standards. These eight should be developed as processes, either by the industry within the three Organization Standards or by individual industry owners/participants. For instance, the E-Tag system was developed by the industry, facilitated by NERC, and is one part of the process for meeting the intent of "Coordinate Interchange", which itself is a process under "Balance Resources and Demand" and/or "Coordinate Operations". The existing TLR process was developed by the industry to assist industry participants meet the core Organization Standard "Operate Within Limits - Monitor and Assess Short-Term Transmission".

Others of the SARs should be developed by individuals but do not themselves rise to the level of "core reliability" Organization Standard. For instance, every system operator should have plans for recovering from blackout or islanding conditions, "Prepare for and Respond to Blackout or Island Conditions". However, we believe these processes should be developed by individual operators, unique to their own systems, and are not core Organization Standards.

Further comments on the individual SARs are included below for your consideration.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments:

This SAR is really a requirement to establish a "process" for assessing and planning the transmission system. We view the contents of this SAR to be one of the "how"s for meeting the renamed Organization Standard "Operate Within Limits - Monitor and Assess Short-Term Transmission" . As such, this SAR does not rise to the level of "core reliability" Organization Standard.

The industry currently has in place regional processes for assessing and planning the power system under a variety of normal, abnormal, and extreme system conditions. The process should be continued, updated if necessary, and participation in the process should be a required activity by all industry participants.

SAR Commenter Information			
Name	Michael Desselle		
Organization	American Electric Power		
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American Electric Power (AEP) appreciates the opportunity to comment on the 10 most recent Standard Authorization Requests (SARs) and looks forward to working with NERC and other market participants to ensure the continued reliability of the electrical system.
Clearly the electricity industry has been exceptionally dynamic and fluid in recent years and is going through many changes. While changes can be positive, it is incumbent on the industry to ensure that changes, which are adopted result in enhanced reliability and a better market environment. With this in mind, we envision that there are actually three interrelated but separable processes with respect to the development of standards.

? First, the relevant standards need to be identified. Over recent months this has been referred to as defining "what" the standard is.
? Second, there need to be decisions about "how" these standards are to be achieved.
? Third, choices have to be made as to how these standards will be implemented.

The resultant standards, when implemented and operational, will potentially affect production, consumption and investment decisions. By necessity, the standards, including how they are achieved and implemented, are closely related to the design of the market and the separation of functions among market participants and service providers. For this reason, we encourage discussion and even preliminary definition of what core reliability standards are needed. However, we strongly urge restraint with respect to the other two aspects of the process – defining how the standards will be achieved as well as how they will be implemented. In our opinion, the latter two processes are highly integrated with the process of market design and implementation as well as market operation; the development of RTOs; and the definition of the NERC/NAESB interface.

Given that closure on many of the market design issues is expected in the near future, we see little risk in delaying the latter two processes – how the standards are achieved and implemented - until such time as clarity is achieved on Standard Market Design (SMD) and RTO formation. Moreover, since the NERC/NAESB interface will likely impact decisions on how standards will be achieved as well as how they will be implemented, it seems logical to wait until that interface has been defined.

We would prefer to see the SAR process simply make the threshold determination as to whether each of the proposed standards are needed, and then put on hold the actual development of those standards that are needed until the critical market development activities described above are closer to completion. Only at that point in time, will it be known whether the proposed standards cover the scope of performance needed to ensure reliability of the interconnected North American Grid. In the interim, AEP looks forward to continue working with NERC, NAESB and other market participants to develop and implement the appropriate standards.

Other comments: It is unclear to AEP what the intent was of this SAR . This SAR appears to have both market and reliability implications. As such, before moving forward to develop this SAR, AEP requests a further clarification of the specific intent. To the extent that this SAR is transitioning an existing standard from the old world to the new world (Functional Model), then the standard should not go beyond the original scope. Consistent with our general comments, once the clarity is achieved on Standard Market Design and RTO formations, then this standard should be revisited and reevaluated.

SAR Commenter Information			
Name	Ed Kirschner		
Organization	Cinergy		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: General comment on entire set of SAR's and the overall process: Based on the short descriptions and the broad scope of most of these SAR's, it appears that these SAR's will encompass many of the existing planning and operating templates developed during the NERC pilot program. Experience obtained during the pilot program showed that many of the planning templates and some of the operating templates were difficult to interpret and even more difficult to measure for compliance, let alone determine exactly who the templates applied. Based on the scope descriptions given for each SAR, it appears these SAR's are written to encompass those same templates. Hopefully, the final standards will be written such that each standard is clear and concise as to how exactly the entity must comply for different levels of compliance and exactly which entities must comply for each measure of each standard. With the benefit of experience of the pilot program, Cinergy would like to suggest that since several of the measures in the existing templates are difficult if not impossible to actually measure for compliance, that some of these proposed standards or portions thereof not be developed into standards but instead be written as "good engineering practices". These "practices" could be used in the certification process for the various functions in the NERC Functional model such as Reliability Authority, Planning Authority, etc. We will try to indicate on each SAR, those portions that should be written as "practices". In the event that all eleven of these SAR's are approved to move forward, then the list should be prioritized and developed somewhat consecutively instead of simultaneously. We have already observed how difficult it is to stay abreast of the templates developed during the pilot as far as providing meaningful comments and review due to the sheer volume of documents distributed for review. Although there are only eleven SAR's, each SAR encompasses multiple measures, which will need to be defined in order to specify how each part is to be measured for compliance and to define what entities must comply for each part. Also since technical experts will be required to assist in the development of these standards, there will be a burden on resources if all of these are developed simultaneously since many of the standards could involve some of the same experts. The priority of developing each standard should be based on industry consensus of what are the major problems/issues that are threatening the reliability of the transmission grid today. Standards should be written so that performance can be measured as it affects overall grid reliability vs trying to measure practices or procedures.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: entire standard

Other comments: This SAR should be developed as a "practice" to be used in the certification process for Planning Authorities and Reliability Authorities. Experience with the existing templates and NERC Table 1A shows how difficult it is to not only determining how to comply with this standard but to actually measure it for compliance. It is difficult if not impossible to determine if events will result in "cascading" - usually engineering judgment is used. It is also not practical to investigate every possible extreme or abnormal system condition to check for "cascading" - again engineering judgment is used. All of these factors makes measuring an entity for compliance very difficult if not impossible. Based on the ongoing development of RTO's and the open stakeholder process proposed for future planning studies, it does not appear that lack of planning will be an issue.

SAR Commenter Information			
Name	Jim Griffith		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Frequency control and processes standardized to speedy determine what are the problems contributing to poor frequency. What is considered "poor frequency"? Some SARs do not include critical participants that should be included.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: The scopes of these SARs range from small details to broad areas of responsibilities and overlap in many areas. It would seem that a top down approached would make better sense.

None

SAR Commenter Information			
Name	Peter Burke (submitting comments provided by numerous ATC contributors)		
Organization	American Transmission Company		
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E-mail	PBurke@atcllc.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: (1) ATC applauds the effort of the SAR's to acknowledge the dismantling of the vertically integrated utilities. However, some care needs to be given to defining the separated groups. For example, it is not always clear what is meant by Planning Group, Transmission Owner, Transmission Service Provider, and Transmission Operator, whether some groups are included in others, and whether there should or shouldn't be that inclusion. For each of the SAR's, there was some lack of confidence that the correct complying entities had been identified.

(2) Perhaps buried within the SAR's is a modeling component that will surface in the details, but none of these SAR's will accomplish their intent without credible models from which to do analysis.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: SAR #8 includes coordinated "planning". This language should be added here so that the Assessing and Planning of the Transmission System is coordinated. If modeling isn't addressed in the details it should be.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: (1) It is not clear how market solutions would fit in providing reliable delivery of power for the future needs of customers. Market solutions could provide an interm solution to transmission constraints but they should not be used in planning future transmission needs.

Maybe the transmission service provider (TSP) should have some responsibility within this area as it relates to providing adequate transmission service to the market. If the TSP identifies a bottleneck on the transmission system creating problems transferring energy across the system, that should be included in future plans to try to eliminate that bottleneck.

The transmission operator, if not the same as the transmission owner, should have some responsibility in making sure the transmission owner knows about future improvements needed to improve it's system from an operational perspective.

(2) NERC should ensure that the standards defined within this SAR include a definition of how the planning model is created. Is there any way to come up with a standard for what gets included in the future models? For example, roll-over rights for transmission service, proposed generation facilities, proposed transmission facilities that require state approval and/or signficant right-of-way acquisition.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: SARs should be developed that cover Operator Personnel and Training and Telecommunications reliability.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The SAR should also apply to the following organizations because of their involvement in the planning process: Transmission Service Provider, Transmission Operator, Distribution Provider, Generator, Purchasing-Selling Entitiy, and Load-Serving Entity.

SAR Commenter Information			
Name	David Little		
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Is there a reliability-related need for an Organization Standard to be developed on this topic? ☒ Yes ☐ No ☒ Yes ☐ No The scope of the SAR is fine as it is			

SAR Commenter Information			
Name	Art Giardino		
Organization	Public Service Electric & Gas		
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E-mail	arthur.giardino@pseg.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: Too soon to proceed

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Resources should not be expended on this SAR until FERC has specifyed the organization responsible for wholesale electric standards development.

SAR Commenter Information		
Name	Compliance Subcommittee	
Organization	SERC (Contact = Nancy Fallon)	
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E-mail	nfallon@serc1.org	

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: A lot of vital requirements of existing policies are not included in any of the proposed SARS, i.e., time error correction, inadvertent, etc.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: It appears that some of the SARS overlap and cover some of the same areas, such as "Prepare For and Respond to Emergency Conditions", "Prepare for and Respond to Blackout or Island conditions", and "Monitor and Analyze Disturbances, Events, and Conditions". These could all fall under a single Emergency Operations SAR. "Coordinate Interchange" should also fall under "Coordinate Operations". In addition, the SARS are intended to define standards for core reliability functions, i.e., "what to do". Some of the SARS really describe processes (i.e., "how to do it") rather than define standards, such as the SAR on "Determine Facility Ratings, Operating Limits and Transfer Limits". There are others that may need to be combined - it is suggested that a re-mapping of Policies to specific SARs should be done.

None

SAR Commenter Information		
Name	OPWG	
Organization	SERC (Contact = Nancy Fallon)	
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E-mail	nfallon@serc1.org	

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The "Assess Transmission future needs and develop transmission plans" SAR does not state a requirement to plan the system so that it can be operated within operating limits. We feel that this terminology (operating limits or other term such as Operating Security Limits) should be common among all SARs. The system must be planned so that it can be opearated reliably. Using this terminology in all SARs would provide the appropriate link among them.

Without knowing the details that will be included in the standards as described by these SARs, it is difficult to make an assessment on the completeness of this set of SARs. We feel that there should be a SAR that requires LSEs, distribution providers, and generators to respond to requests that will have the effect of operating the system within Operating Limits.

None

SAR Commenter Information		
Name	Planning Standards Working Group (PSWG)	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Maintenance requirements should cover transmission equipment other than just protection and control equipment.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:
Other comments: For the Applicable Functions, TSP, T-owner, and T-operator could all apply. We question whether RA should be applicable. Was the RA inclusion possibly a holdover from when the Planning Authority was not developed?

The scope of this SAR seems rather large, perhaps it could be divided into more manageable pieces.

SAR Commenter Information			
Name	Gary Won and Don Tench Comments submitted on behalf of the Independent Electricity Market Operator (IMO)		
Organization	Independent Electricity Market Operator (IMO)		
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E-mail	gary.won@theimo.com and don.tench@theimo.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No - see comments

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

Comments:

The proposed standards appear to provide the necessary coverage to ensure a reliable interconnected North American grid. A thorough review will need to be done to ensure that no necessary and significant performance requirement is missed that is in the current Operating Policies and Planning Standards. While the proposed SARs may cover the scope of performance needed, we have several concerns with the overall set at this stage of implementation;

1. The 'White Paper on NERC's set of Organizational Standards", dated April 11, 2002, clearly articulates a direction with which we agree. The paper proposes that 'these standards will define ***what*** performance must be achieved, without providing restrictive measures on ***how*** to achieve that performance'. This direction arose following industry experience with the very large set of current planning and operating standards and recognition by the industry that the current standards, in many areas, are too prescriptive of the 'how'. By focusing the industry on meeting less meaningful standards, the goal of maintaining reliability is actually put at risk. It is our belief that the proposed set of standards still focuses too much on the 'how', to the potential detriment of the overall objective.
2. Perhaps the most important aspect of a set of organization standards is to define to whom and to what the standards apply. The NERC Functional Model does a good job of providing a framework to define to whom the standards apply. However, what the standards apply to is left almost entirely open. What the standards apply to is variously described in the proposed SARs as the; transmission system, interconnected transmission system, network, power system, bulk electricity system and those facilities which affect reliability, among others. The white paper again provides valuable insight by defining the objective in terms of the 'interconnected electric systems in North America', however, this too is subject to individual interpretation. A definition of what the standards apply to, in terms of scope, is perhaps more important than the individual SARs. As such, I suggest that this scope needs to be developed through the SAR process. This needs to be addressed in a global fashion rather than relying on the development of a different scope for each SAR.
3. The proposed SARs deviate from the white paper direction to focus on reliability and delve into areas which are potentially outside of their scope such as; equipment damage, data sharing, procedures and studies. To the extent that these areas are performance related, the need is understood. However the development of past standards has shown that these areas often become part of a standard when they are really only one method of how a given level of performance can be achieved.
4. The 'High Level Map of Old Doc's to new Doc's' proposed by SAC (attached at the end of this package) provides a mapping of existing NERC planning and operating standards into the proposed new SARs. Each of the broad areas defined by the existing standards must be judged carefully against the 'White Paper' principles before even being included in the mapping. It is our belief that many will not pass this test.
5. The language of the proposed set of SARs struggle (understandably) to recognize the industry changes facing open electricity markets. Often they reflect a historic utility perspective including distinctions between 'planning' and 'operating' and emphasis on elements of 'pro forma' tariffs, which may no longer be relevant. To the maximum extent possible, the SARs must be developed to be independent of organizational and regulatory structures as well as respecting Regional and international differences. In our view, performance based standards are the best way to recognize this diversity.

We are very supportive of the goals NERC has set and would be glad to discuss further or participate more directly in their development.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate:
The SAR must be rigorously tested against the White Paper requirements to specify what performance must be achieved rather than how to achieve that performance. For example, in what way is a standard for 'planning the transmission systems' a performance standard? Wouldn't such a standard be considered one means of determining whether a performance standard based on system behaviour (both present and future) is met?
Other comments: The Standard description implies that there should be a single transmission expansion plan. It reads as if there is or must be a single coordinated and minimum cost plan (same theme in the Planning Authority proposal currently being circulated for comment). In a market environment, there may be a need for multiple plans since the viability and timing of various generator projects (and the system enhancements that may be required for deliverability of their output) will be dictated by commercial rather than system adequacy considerations. Similarly the timing of merchant transmission projects will reflect commercial rather than system security considerations

A minimum set of criteria for assessing the acceptability of plans is needed. The NPCC A-2 (see www.npcc.org) document covers the aspects of ensuring against significant (disagree with the use of "extreme" in the SAR), adverse impacts over a wide area. Market systems also need criteria to determine when to initiate or order plans, or trigger some regulatory backstop if expansion plans are deemed to be insufficient to meet needs. (Must also define what minimum need is).

SAR Commenter Information		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The promulgation for comment of these SARs is premature. The industry "standard making process" is in a transition phase and it is overly burdensome to devote resources at this time. Once legislation or FERC firmly determines which entiy(ies) is responsible for standards it will make sense to move forward with said entity.

Even if NERC wants to cover reliability standards, almost all standards have a reliability and commercial impact; thereby, necessitating developing a single process that incorporates both commercial and reliability aspects of standards development. The current NERC process risks being changed soon, discounts commercial aspects, and is not part of a finalized overall industry process.

Waiting a short while to move forward on a new standards setting process is acceptable and prudent given that NERC standards are currently in place and the industry can continue to use these standards until the new process and standards setting organization(s) are firmly set.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: The promulgation for comment of these SARs is premature. The industry "standard making process" is in a transition phase and it is overly burdensome to devote resources at this time. Once legislation or FERC firmly determines which entiy(ies) is responsible for standards it will make sense to move forward with said entity.

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Waiting a short while to move forward on a new standards setting process is acceptable and prudent given that NERC standards are currently in place and the industry can continue to use these standards until the new process and standards setting organization(s) are firmly set.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The promulgation for comment of these SARs is premature. The industry "standard making process" is in a transition phase and it is overly burdensome to devote resources at this time. Once legislation or FERC firmly determines which entiy(ies) is responsible for standards it will make sense to move forward with said entity.

Even if NERC wants to cover reliability standards, almost all standards have a reliability and commercial impact; thereby, necessitating developing a single process that incorporates both commercial and reliability aspects of standards development. The current NERC process risks being changed soon, discounts commercial aspects, and is not part of a finalized overall industry process.

Waiting a short while to move forward on a new standards setting process is acceptable and prudent given that NERC standards are currently in place and the industry can continue to use these standards until the new process and standards setting organization(s) are firmly set.

SAR Commenter Information		
Name	R. Scott Henry, Chairman	
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: The IOS Subcommittee appreciates the opportunity of submitting comments on the ten SAR's posted by NERC. The IOS Subcommittee found the white paper most instructive in explaining the intent of this initial posting. Generally, the SAR's posted outline the topics for a reasonable first set of organization standards. Since much work is still to be done in developing the details of the SAR's and the related organization standards, a definitive statement on the comprehensive nature of these SAR's is premature at this point. The IOS Subcommittee does note that interconnected operations services are important components of several of the SAR's. NERC's IOS work, summarized in the IOS Reference Document in the NERC Operating Manual, has been substantive in identifying the minimum necessary components of interconnected operations services. Addressing more than simply the need to balance energy, the IOS work stresses the importance of responsive capabilities and controls necessary to achieve reliable bulk electric operation. The IOS Subcommittee recommends that the drafting of the proposed standards considers the IOS Reference Document and that IOS expertise be considered an essential competency of the standard drafting team.

In its discussion of these SAR's, the IOS Subcommittee identified three fundamental policy issues needing resolution prior to detailed work on development of these standards. First, the SAR's generally propose that the organization standards would apply to Service Functions contained in the Reliability Model, and they do not propose addressing the role of generators, loads, and others in provision and delivery of IOS's. The SAR's implicitly assume that the roles of others will be addressed through contracts. While the IOS Subcommittee does not necessarily disagree with this assumption (no consensus has been reached either way), there is a need to further explore the potential applicability of aspects of the proposed standard to others. This issue requires further debate and may serve as a critical precedent for the scope of other Organization Standards. Second, the "Assess Transmission Future Needs and Develop Transmission Plans" SAR proposes a standard to develop plans. None of the SAR's identifies who has the obligation to implement the plan. A plan without assignment or accountability for implementation is likely to provide no fruitful results. Third, the proposed standards and associated measures and criteria should not be any more restrictive than is necessary for a reliable bulk electric system. Market mechanisms for the provision of IOS should not be unnecessarily constrained. Market design is evolving rapidly, including for example, the ability to provide real time balancing services through bid-based mechanisms.

The IOS Subcommittee offers its assistance to the Standards Requestor(s) as further work is invested in development of these organization standards.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No
☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: This is an ongoing function that will be coordinated by RTOs with transmission owners and market participants. Every RTO will have or already has a planning protocol on how long term transmission plans are developed. A standard is not needed to make this function occur. For those entities not in an RTO, a similar process will exist to develop long term transmission plans.

SAR Commenter Information			
Name	Kent Saathoff		
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This SAR and the other posted SARs provide an appropriate framework for transitioning existing NERC Operating Policies and Planning Standards into new, NERC Organization Standards. Multiple compliance measures may be defined and developed for each of the eleven proposed Organization Standards. The Organization Standards and related compliance measures should focus on what functions must be performed for reliability, on who is responsible for each compliance measure for each required function and not, on how the compliance measure is achieved. The compliance measure must be measurable or demonstrable to ensure compliance.

Sound planning is the foundation for a reliable transmission system. Therefore a standard for defining transmission planning requirements is appropriate.

ERCOT believes the following issues should be considered in the development of this standard:

· The assessment leading to a transmission plan may be the most important aspect of this standard. Operational challenges must be identified, coordinated and remedial action plans made. Facility solutions usually require a longer time frame than the operating requirements allow.

· Incorporate a reasonable planning horizon - Sound planning must be based on reasonably accurate forecasts of future load and generation patterns. In the new competitive generation markets it is not possible to perform meaningful forecasts more than five years out. Attempting to do so is not a good use of scarce resources.

· Allowance of Remedial Action Plans (RAP) and Special Protection Schemes (SPS)– Major transmission construction that may be the preferred long-term answer to transmission reliability usually has a long lead-time. There should be provisions for the interim use of RAP and SPS in meeting the planning standard.

· Recognition of Regional differences - All standards should make allowance for reasonable differing regional requirements. Requirements may vary due to differences in climate, predominate generation type, transmission design standards, availability of interruptible load and market rules.

· FACTS devices are emerging as feasible solutions to transmission improvements. They should be considered in the development of standards for transmission planning and facility ratings (may include in SAR ID# FACILITY_RATINGS_01_01 as well).

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: We did not have adequate time to be sure all reliability areas are covered by these SARs.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: 1) a requirement to provide assessments at all demand levels 2) Transmission Service Providers should be included in the list of functions.

☒ The scope of the SAR should be reduced to eliminate: This standard should only apply to long-term planning functions. A parallel standard is required for operational planning.

SAR Commenter Information			
Name	Linda Clarke		
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E-mail	lclarke@pwrteam.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

The reliability policies, or "Organization Standards", must be specific and limited to standards based on the NERC-defined seven reliability principles and five market interface principles and not go beyond these areas. In addition, the NERC Organization Standards process must be coordinated with the process that will be established by FERC to develop busines practice standards.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: A SAR is not needed for a transmission expanision plan, since it includes "market solutions". Market solutions are outside NERC's scope with respect to the development of reliability policies or "Organization Standards".

SAR Commenter Information			
Name	Carter B. Edge		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☐ Yes ☒ No If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Time Error Corrections; Inadvertant Interchange			
Is there a reliability-related need for an Organization Standard to be developed on this topic? ☒ Yes ☐ No			

SAR Commenter Information			
Name	Warren Schaefer		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: We are not sure from the brief scope that is provided with each SAR that all the NERC Planning Standards and Operating Policies are covered.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☒ The scope of the SAR should be expanded to include: 1) a requirement to provide assessments at all demand levels 2) Transmission Service Providers should be included in the list of functions.
☒ The scope of the SAR should be reduced to eliminate: This standard should only apply to long-term planning functions. A parallel standard is required for operational planning.

Other comments: This is a reliability standard and should not include Market functions

SAR Commenter Information			
Name	Mike Miller		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: The "Assess Transmission future needs and develop transmission plans" SAR does not state a requirement to plan the system so that it can be operated within operating limits. I feel that this terminology (operating limits or other term such as Operating Security Limits) should be common among all SARs. The system must be planned so that it can be operated reliably. Using this terminology in all SARs would provide the appropriate link among them.

Without knowing the details that will be included in the standards as described by these SARs, it is difficult to make an assessment on the completeness of this set of SARs. I feel that there should be a SAR that requires LSEs, distribution providers, and generators to respond to requests that will have the effect of operating the system within Operating Limits.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: Planning must be coordinated to optimize not only transmission but generation as well. The left alone process of disjointing generation and transmission is creating a non-steady state electrical system. The criteria for designing a system must include defined measurements adopted by all. This brief description does not provide sufficient detail to ensure reliability is planned. The planning criteria must address defined transmission planning for transfer usage as well as specific load service usage in other words interconnection as well as intraconnection. The need to define roles, responsibilities and authority must be developed between Federal (RTO) characteristics and functions and transmission owners.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Transmission Operator and perhaps Distribution Provider should be added to the list of applicable functions.

SAR Commenter Information			
Name	Jim Griffith		
Organization	Bulk Power Operations Southern Company		
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E-mail	jsgriffi@southernco.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Frequency control and processes standardized to speedy determine what are the problems contributing to poor frequency. What is considered "poor frequency"? Some SARs do not include critical participants that should be included.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: The scopes of these SARs range from small details to broad areas of responsibilities and overlap in many areas. It would seem that a top down approached would make better sense.

None

SAR Commenter Information		
Name	Southern Company	
Organization		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☐ Yes ☒ No
If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:
The new Organizational Standards must include the "How's" as well as the "What's" to just maintain the current level of reliability for the electric transmission system. The current NERC Planning Standards and Operating Policies, in general, document the body of good utility practice that provides that currently level of reliability seen in North America. If only the Standards ("What's") were published without the Measures ("How's") the new document will be woefully inadequate. The planning, design, construction, operation and maintenance of the electric transmission system are a very refined process of applied scientific principles and technology. The current proposed Organizational Standards create a level of ambiguity that will not adequately ensure the reliability of the grid is maintained at the levels seen today. Southern Company suggests that NERC consider withdrawing the entire proposed set of standards and reconsider its process for developing reliability standards. When posting standards for comment, NERC should consider a longer comment period. Thirty days is too short due to the amount of corporate coordination and information gathering required to submit meaningful responses.
With respect to the scope of reliability standards, the development of all reliability standards should be within the general context of ensuring that the grid is protected from uncontrolled or cascading interruption of network operation. None of the proposed SAR's fully addresses these basic operational requirements, although certain aspects of these requirements are contained within some of the SAR's. Therefore, it is recommended that NERC prepare an initial standard that establishes the minimum reliability requirements needed to prevent severe adverse events from occurring on our transmission system, i.e. uncontrolled or cascading interruption of network operation. This pivotal standard - call it "MINIMAL OPERATIONAL REQUIREMENTS" - would address such basic reliability considerations such as

- No operator should knowingly operate in a manner that inappropriately affects the reliability of another entity
- No operator should allow operation of the system in such a manner that inappropriately risks cascading outage of the network or violates an operating security limit.
- No operator should allow operations that violate safety standards established by the National Electric Safety Code, ANSI Standards, IEEE, etc….
- No operator should allow operations outside established equipment ratings
- Etc.

These may or may not represent the appropriate set of minimal reliability considerations, and are offered for illustrative purposes only. Once this pivotal standard has been established and fully vetted, all future SAR's can be developed within the context of these basic requirements. If it were deemed necessary to increase or adjust these pre-established minimum levels, the pending adjustments would need to be fully vetted in both the commercial and the reliability forums.

Is there a reliability-related need for an Organization Standard to be developed on this topic?
☒ Yes ☐ No
☐ Yes ☒ No the scope of the SAR is fine as it is
☒ The scope of the SAR should be expanded to include:
The scope of this SAR is poorly written and does not adequately represent or convey the transmission planning functional responsibilities. A better way to phrase the purpose could be:
To establish a standard for evaluating the performance of the transmission system to ensure that appropriate levels of functionality and reliability are achieved in both the short-term and long-term time frames.
☐ The scope of the SAR should be reduced to eliminate:
Other comments:
The "Brief Description", once again, is poorly written and does not represent transmission planning in general.
The I.A. Planning Standard is a very functional standard with the exception of S3.M3 and should be

followed very closely as a template to the developing the scope of this SAR.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: responsibility for maintaining adequate operating reserves and reactive support. (Perhaps to be included in SAR on "Balancing Resources and Demand"?); responsibility for assessing and defining what are adequate operating reserves and reactive support. (Perhaps to be included in SAR on "Developing Transmission Plans"?)

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: responsibility for assessing and defining what are adequate operating reserves and reactive support.

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Load and Generator entities are just as integral as Transmission Owners to the planning of the system. This should incorporate the responsibilities of all entities to provide information necessary for assessment.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Standard requirements that establish a consistant and reliable measure to evaluate the transmission system must be developed and maintained to insure that the transmision system can perform safely and reliably. Requirements that address normal, abnormal, and extreme conditions need to be defined. Standard protocol need to be enforced that addresses future operating conditions of the transmission system that will ensure that events such as uncontrolled seperation or cascading does not occure during any single contingency.

SAR Commenter Information			
Name	Scott Helyer		
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: On SAR ID# PHYSCAL_CON_REQ_01_01, it appears that specifying requirements for operating limits and AGC go beyond the Physical Connection Requirements. We need to ensure that this Standard would not overlap another reliability standard on operating limits and that we do not create a reliability requirement that AGC is needed for all generators when the market should decide which generators require AGC. Writing a standard that indicates how AGC should be provided if a generator wishes to provide such a service would be acceptable.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?
☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: Several of the SAR's contain market related issues. These should be delayed until FERC final ruling on Standardized Transmission Service and Wholesale Electric Market Design

The scope of the SAR should be reduced to eliminate: This SAR proposes "the plan may utililize operating, construction, market solutions or other components to address these conditions." Market solutions requires this standard be developed by a process that take into account market along with reliability interests.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid? ☐ Yes ☒ No If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: We need to add flexibility to allow for Regional differences in all the SAR's. We also need application criteria to provide guidance on when SPS should be applied as permanent measures and when it should be applied as temporary measures to mitigate potential system problems.			
☒ Yes ☐ No ☒ Yes ☐ No The scope of the SAR is fine as it is			

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Application criteria for SPS (or Remedial Action Scchemes) should be included. SPS, thought may be considered as some form of protection and control measure, is applied for many different purposes which may be systems related and not necessary equipment protection related. Clear criteria are needed for consistant application of SPS (RAS) and when SPS (RAS) could be considered as an alternative to mitigate for system deficiencies. Planning criteria need to provide guidance on when SPS should be applied as permanent measures and when it should be applied as temporary measures to mitigate potential system problems. Special Protection Schemes, Protection Schemes and Control Schemes should all be treated separately.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include:

1) Planning criteria should be expanded to include maintainability of the system. Simple mitigation measures such as removing equipment out of service during lightly loaded and off-peak hours, to make system adjustments and to allow equipment protection against high voltage conditions may not be considered practical since it may crate N-1 operating conditions. Also, possible overall system deficiencies for interconnected systems may not allow such prudent practices such as removing equipment from service.

2) Establish a separate SAR for implementation of various types of SPS - Identify criteria for application of each type such as:
Overload mitigation, Adaptive overload mitigation schemes, UFLS, UVLS, stability related schemes, etc.

3) Develop a plan to address operating issues for interconnected grids systems where SPS is used systematically to mitigate against many different types of system deficiencies within a Region, operating in a coordinated manner with multiple mitigation measures simultaneously operating in parallel creates increased potential for cascading outages following an un-planned outage.

SAR Commenter Information			
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Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: See individual SAR comments.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: See individual SAR comments.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: More detail is needed about what is required in order to write this standard.

☒ The scope of the SAR should be reduced to eliminate: Developing plans. The SAR should only address the creation of Planning Standards - Plan Development is a compliance issue.

Other comments: As written, this SAR does not set a standard, but rather seems to try to assign responsibility for setting the standard.

SAR Commenter Information			
Name	Mr Paul Tremblay, Mr. Mike Penstone, and Mr Ajay Garg		
Organization	Hydro One Networks Inc.		
Telephone	416 345-5420	Fax	416 345-5422
E-mail	ajay.garg@HydroOne.com; mike.penstone@HydroOne.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

The design of Bulk Electric System is complex and its performance depends upon a variety of factors including but not limited to, designs, configurations, designs, technologies, operating practices, etc. The proposed standards should focus upon required performance objectives and methods of measuring success or failure(ie. PERFORMANCE BASED CRITERIA standards) rather than prescribing the means to achieve these objectives.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed:

As above, standards should not prescribe processes nor means of achieving an outcome. This has been done, effectively, by NPCC for over 25 years.

NERC standards should facilitate in the establishment of Region/RTO/Area specific standards that will meet the NERC performance standard.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate:

SAR Commenter Information			
Name	Marv Landauer		
Organization	BPA		
Telephone	360-619-6602	Fax	360-619-6945
E-mail	mjlandauer@bpa.gov		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing:

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: I do not think it is appropriate at this point in the process to define the Reliability Functions that are associated with the Standard and cast them in concrete (which Maureen has indicated is the case). As the standards are drafted. issues may come up that need to be includeded that will require coverage by other reliability functions. If they are defined early in the porcess, they should be subject to revision later as necessary.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: The description should be modified to only include "performance under a variety of PLAUSIBLE system conditions". Why aren't the load and generator functions involved in this standard? Aren't they the ones the system is built for? As I mentioned above, I believe that making the connection between Reliability Functions and the SAR should be deferred until later in the process.

SAR Commenter Information			
Name	Francis J Halpin		
Organization	Bonneville Power Administration - Power Business Line		
Telephone	503 230 3000	Fax	503 230 5669
E-mail	fjhalpin@BPA		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: Drafting team should rely heavily upon existing NERC Reliability Criteria in the development of this standard.

Should include Generator and LSE to the list of functional entities to which this standard would apply. Generators and loads are both key factors in the planning process for future transmission needs and should therefore be subject to the requirements of this standard.

SAR Commenter Information		
Name	Edward Stoneburg	
Organization	Illinois Power Company	
Telephone	(217) 362 6363	Fax
E-mail	edward_stoneburg@illinoispower.com	

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: There is inadequate detail provided to allow a determination of whether the proposed set of Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American Grid. The answer to this question will depend upon the specifics included in each SAR. Detailed SARs must be developed and recirculated before any work begins on development of detailed Organization Standards. These SAR's should be specific about the WHAT of what is the reliability requirement and WHO is obligated to comply (but does not necessarily need detail as to HOW and should not set commercial practices as to HOW to comply) .

Illinois Power suggests the following approach to developing an adequately detailed SAR:

1) For each Function, determine what are the necessary standards to which the provider of that function should be held to in order to ensure reliability. This should not be a wholesale transfer of existing NERC Operating Procedures and Planning Standards into Organization Standards.

2) Consideration should be given to having Standards that apply clearly for each Function rather than multiple Functions being addressed within topical Standards. In that way a Balancing Authority, for example, would only need to be concerned with one Standard, not sorting through multiple standards to figure out what applies to them. Much easier for training their people, keeping track of changes, etc.

3) Each SAR should clearly identify specific and measurable requirements. This aspect is key and should not be left to the later development work, nor should the Standard Writers have authority to expand the specific, measurable reliability requirements without coming through the SAR process.

Should NERC decide to proceed based upon the information submitted for comment, Illinois Power has provided specific comments on each SAR.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: See above

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☐ No **THE INTENT OF THIS STANDARD IS UNCLEAR SUCH THAT WE CANNOT DETERMINE IF THERE IS A NEED**

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: Reliability Authorities: In reviewing a Reliabilty Authorities responsibilities, it does not appear to Illinois Power that the RA has any responsibility to assess FUTURE needs or develop FUTURE plans, and therefore would not be subject to this Standard

Other comments: There is inadequate detail in the SAR to determine if the scope of the SAR is appropriate and adequate. A standard in this area should focus on the minimum frequency of assessment and the definition of normal, abnormal, and extreme conditions that must be studied. The creation of a plan should not be a measurable standard as implied in this SAR. Nor should the Standard require specific operating, construction, or market solutions. It should only define the reliability requirements

SAR Commenter Information			
Name	Saif Mogri		
Organization	WECC Technical Studies Subcommittee		
Telephone	(213)367-0447	Fax	(213)367-0457
E-mail	smogri@email.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Flexibility allowing for Regional differences in all the SAR's.

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: Further comments on SAR's will clarify some of our thoughts.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	Gerald N. Rheault		
Organization	Manitoba Hydro		
Telephone	(204) 487-5423	Fax	(204) 487-5360
E-mail	gnrheault@hydro.mb.ca		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: A separate Standard should be developed related to operational planning requirements. In your proposed SARs, the operational planning function is included in SAR 1 along with the new facility planning function. Although there are a lot of similar activities requiring similar tools in either function the criteria system consideration and level of detail involved is quite different. Therefore they should be two Separate SARs to address the Standards requirement relative to these activities. Further discussed in SAR1 comments

If you believe there are some performance areas that are included in the proposed set of Organization Standards but are not needed, tell us what you believe is not needed: SAR 7 "Coordinate Interchange" as written seems to reference the function of creating transactions which is a Business Standard. This SAR to reference the reliability requirements of interchange should be related to SCHEDULED Transactions and the data and monitoring requirements associated with this activity. This is further discussed in SAR7.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: functionality related to assessing transmission performance and relate only to planning future transmission expansion.

Other comments: This SAR's Purpose/Industry Need should be modified in the following way:

the Purpose statement should have the word "assessing" removed so it addresses a planning function only.

The Industry Need comment should be changed to the following "The transmission system must be planned to ensure the reliable delivery of energy and power to meet the needs of customers. A reliable supply of electricity is essential to ensure the safety and economic viability of modern North American society."

Transmission Service Provider should also be included in the list of complying functions.

SAR Commenter Information			
Name	Donald D. Taylor, PE		
Organization	Westar Energy		
Telephone	785-575-6430	Fax	785-575-1798
E-mail	don_taylor@wr.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☒ Yes ☐ No

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☐ The scope of the SAR should be reduced to eliminate:

Other comments: These comments apply to the complete set of Proposed Organization Standards. Among the set of SARs, the references to "Reliability Function(s) That Would Need to Comply With This Standard" is not consistent. Ensure the "Function Definitions" from The NERC Functional Model are used consistently throughout. All of the "Reliability Principle(s)" should be listed first to ensure the reader knows what all of them are. In the SAR form they are referred to as "Reliability and Market Interface Principles". It appears that the term "interconnected bulk electric systems" is not consistently used.

The Brief Description refers to "or other components to address these conditions." The vagueness is problematic as was discovered in the crafting of the original NERC Planning Standards.

SAR Commenter Information			
Name	Frank A. Venhuizen		
Organization	NIPS (Northern Indiana Public Service Co.)		
Telephone	(219) 647-5630	Fax	(219) 647-5663
E-mail	favenhuizen@nisource.com		

Does this set of Proposed Organization Standards cover the scope of performance needed to ensure reliability of the interconnected North American grid?

☐ Yes ☒ No

If you believe there are some performance areas not covered with the proposed set of Organization Standards, tell us what is missing: Need to add standards covering Reliability Authority responsibilities and authority; and Telecommunications.

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: market solutions" in the last sentence of the Brief Description.

SAR Drafting Team Roster
Assess Transmission Future Needs & Develop Transmission Plans

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Standard Authorization Request Form

Name of Proposed Standard	Certification of the Balancing Authority Function
Request Date	October 7, 2002
Authorized for Posting	November 20, 2002
SAR ID#	BA_CERTIFICATION_01_04

SAR Requestor Information		***SAR Type***	
Name	Organization Certification Task Force	☒	1. New Standard
Primary Contact	Gerry Burrows	☐	2. Revision to existing Standard or
Telephone	816-654-1183	☐	3. Withdrawal of existing Standard
e-mail	gerry.burrows@kcpl.com	☐	4. Urgent Action

Purpose/Industry Need of Standard

To ensure that each entity that wants to be recognized as a Balancing Authority has the capability of performing the responsibilities assigned to the Balancing Authority function.

Brief Description of New Standard or Revision to Existing Standard

Each entity that wants to be recognized as a Balancing Authority shall demonstrate that it has the processes, procedures, tools and agreements in place to demonstrate that it has the capability of performing the responsibilities assigned to the Balancing Authority Function.

Detailed Description of New Standard or Revision to Existing Standard

Summary

The primary steps in the Balancing Authority Certification Process, and the entity responsible for each step, are as follows:

- Initiation of Process – Entity seeking certification (the "Applicant")
- Provision of criteria, process, documentation, etc. – Region
- Formation of Certification Review Team – Region
- Data collection – Region
- Data review – Region (Review Team)
- Site visit – Region (Review Team)
- Recommendation – Region (Review Team)
- Certification and Authority to operate – Region
- Notification of authority to operate – NERC

Balancing Authority Certification Process

1. Single BA in Single Region:

An entity seeking certification as a Balancing Authority (the "Applicant") will initiate the certification process by making a formal request to the Regional Manager in the Region where the Applicant plans to operate a Balancing area. A copy of the request will also be sent to the NERC Director-Compliance.

Single BA in Multiple Regions

An entity seeking certification as a Balancing Authority (the "Applicant") in multiple Regions will initiate the certification process by making a formal request to one of the Regional Managers of a Region where the Applicant plans to operate a Balancing area and copy all other Regional Managers of those Regions in which the Applicant will operate. A copy of the request will also be sent to the NERC Director-Compliance.

2. Single BA in a Single Region

The NERC Region in which the Applicant plans to operate will be responsible for conducting the formal review process and the awarding of certification.

Single BA in multiple Regions

In situations where a BA crosses Regional boundaries, all affected Regions shall participate in the certification process. The affected Regions shall identify one of the affected Regions as the Lead Region. The Lead Region shall be responsible for coordinating the formal review process and the awarding of certification in concurrence with the other affected Regions.

3. A timeline, including specific milestones, shall be agreed to by the Applicant and the Regional or Lead Regional Council. The NERC Balancing Authority Certification Procedure and certification recommendation is expected to be completed within nine months of the date that the initial

request was received by the Regional Manager.

4. The Region or Lead Region will notify all appropriate parties and provide each with the necessary information regarding the Balancing Authority's request for certification, the certification process, and the duties expected from each entity.

5. The Applicant must register in the NERC Master Registry. Registration stays on hold until certification is granted or denied.

6. NERC/Regional Staff will begin the process of making any necessary modeling/software changes. The Applicant and Region will supply necessary information to NERC.

7. The Region or Lead Region will provide questionnaires and related documents that will be used by all entities involved in the certification process. These questionnaires and related documents will be used to address the Applicant's capabilities and actions as they relate to established Balancing Authority requirements. The following list of entities will be recipients of the questionnaires and related documents as each is a source of certification information and data:

- Applicant (i.e. entity seeking Balancing Authority certification)
- Its Reliability Authority and Interchange Authority(ies)
- Generators and Load Serving Entities within the Applicant's Balancing Area
- Balancing Authorities adjacent to the applicant

8. The Region or Lead Region will provide expectations and standards regarding confidentiality and retention of all data reporting, completed questionnaires and forms, reports and recommendations associated with the documentation it provides and receives.

9. The Region or Lead Region will assemble a Certification Review Team charged with the responsibility of determining if the Applicant meets NERC's Balancing Authority Criteria. The Region or Lead Region and the Applicant will agree on the Review Team members before the commencement of the review process. The Review Team will subject themselves to confidentiality agreements for any data or information that is made available to them through the certification review process.

10. The Review Team will consist of a minimum of three individuals. The selected individuals will represent at least three of the categories listed below:

- Interchange Authority
- Balancing Authority
- Reliability Authority
- Transmission Operator
- Generator
- Load Serving Entity
- Regional Staff member
- Regional Compliance Committee member
- Regional Operating Committee member
- Representative from NERC Staff
- Representative from another NERC Region

- Representative from an RTO, when applicable

Review team members cannot be employees of the applicant or any of its affiliates.

Review processes that involve an entity that is performing a function across Regional boundaries shall have a review team that consists of at least one member from each of the affected Regions. These representatives will be selected by the individual Regions that they represent and not by the Lead Region. Regional representation is still subject to Applicant approval. Remaining review team members must represent at least two of the remaining categories.

In the alternative, the Region(s) may elect, with applicant agreement, to engage a completely independent review team.

11. The Review Team will report its initial findings to the Applicant and to the Region(s) based on the information obtained through the initial application and questionnaires. The review Team will request any additional information before making an on-site visit.

12. The Review Team will conduct at least one on-site visit to the Applicant's control center facility. During the visit, the Review Team will:

- Review with the Applicant the data collected through the questionnaires,
- Interview the Applicant's operations and management personnel,
- Inspect the Applicant's facilities and equipment, and
- Review all necessary documents and data.

13. The Review Team will identify any deficiencies (to both the Applicant and to the Region(s)) that must be resolved prior to the review team making their final recommendation. The Review Team will review any follow-up work required by the Applicant until a certification recommendation is made.

14. The Review Team will formulate a certification recommendation based on: data collected and validated from the questionnaires; and from observations and information collected during an on-site visit to the Applicant's facility. The Review Team will support its recommendation through the production of an evaluation review template and a formal report. All members of the review team will have an equal voice in the certification recommendation.

15. Single BA in Single Region

The certification recommendation from the Review Team will be presented to the appropriate Regional committee(s). The certification recommendation is made by the review team and then approved or disapproved by the Region.

Single BA in multiple Regions

The certification recommendation will be presented to the appropriate Regional committee(s) of all the affected Regions by the Review Team. The certification recommendation is then approved or disapproved by all of the affected Regions. The Lead Region will be responsible for verifying the Regional approvals prior to awarding certification.

16. The Region or Lead Region will notify the Applicant of the certification decision. The Region or Lead Region (in consultation with the affected Regions) may award or deny the Applicant's certification as a Balancing Authority. As an alternative, the Region or Lead Region (in consultation with the affected Regions) may grant 'pending certification' to the applicant. The pending certification shall be granted for a period of time not longer than 180 days. Pending certification, does not grant operation as a Balancing Authority. If the Applicant fails to meet the conditions set by the Region(s), within the granted timeframe, the Applicant's certification will be deemed to be the same as denied. If the Applicant meets the conditions set by the Region(s),

within the granted timeframe, the Region or Lead Region (in consultation with the affected Regions) must respond to the Applicant's notification of completion of requirements within 30 days.

17. After the Region or Lead Region has approved the Applicant as a Balancing Authority, they will notify NERC Staff, who in turn, will notify all of the necessary entities as to the date that the Applicant may begin its Balancing Authority operation. Balancing Authority operation shall not begin before the agreed upon date and must commence operation within 12 months of certification. Failure to begin operation within the 12-month period will require the applicant to re-apply for certification.

18. If the Region or Lead Region denies certification, it shall provide the Applicant with a written report containing specific reasons for the denial. If the Applicant disagrees with the Region's(s') decision, it can initiate the Regional ADR process within 60 days of the date of the written denial. If the Applicant fails to initiate the ADR process within the 60-day time limit as identified in the previous step, it may reapply for certification after 90 days from the date of written denial.

De-certification Process

This section describes the process that will be used for the de-certification of a Balancing Authority when the entity does not wish to continue performing the Balancing Authority function and has arranged for a replacement entity to assume its Balancing Authority responsibilities.

1. The Balancing Authority requesting de-certification notifies the Region(s) it operates in that it wishes to be decertified and names the Balancing Authority(ies) that will be assuming its Balancing Authority responsibilities. If the Balancing Authority(ies) assuming the responsibilities is in a different Region, then a Lead Region will be designated and all Regions will be involved in the process.

2. The Region or Lead Region contacts the Balancing Authority(ies) that is to assume the additional Balancing Authority responsibilities to begin the certification process.

3. After the Region or Lead Region has certified the Balancing Authority(ies) assuming additional responsibilities, the Region or Lead Region will notify the Balancing Authority desiring de-certification and NERC staff of the date the Balancing Authority will cease operation.

4. NERC will notify the appropriate entities of this date.

Balancing Authority Certification Criteria

Introduction

These Criteria establish the requirements for certification as a NERC Balancing Authority. They are based on NERC Reliability Standards, NERC Operating Policies and Planning Standards, and the NERC Functional Model. NERC Policies and Standards applicable to the Balancing Authority function must be adhered to until they are replaced by Reliability Standards or retired.

Definition of the Balancing Authority Function

Integrates resource plans ahead of time, and maintains load-interchange-generation balance within its metered boundary and supports system frequency in real-time.

Certification Criteria

1. **Confirmation by Regional Council.** To be recognized as a NERC-Certified Balancing Authority, the entity must be reviewed and confirmed by the Regional Council(s) in which the entity operates.

2. **Agreements.** Agreements[1] must be in place defining the responsibilities and authority of the Balancing Authority with respect to the Reliability Authority, Interchange Authorities, Transmission Operators, Transmission Service Provider, Generators, Load Serving Entities, adjacent BAs, and all other applicable functional entities within its Balancing Area. Agreements shall address both normal and emergency operations.

3. **Personnel**

3.1. Must have NERC-certified system operators performing the Balancing Authority responsibilities 24 hours a day, 7 days a week.

4. **Data Acquisition and System Analysis**

4.1. Procedure and tools in place to ensure resources/demand balance in compliance to NERC Standards.

4.2. Procedure and tools in place for providing frequency control.

4.3. Procedure in place describing the interchange schedule implementation process.

4.4. The organization must have the ability to monitor and control its metered boundary with regards to data such as:

4.4.1. ACE

4.4.2. Interchange

4.4.3. Frequency

4.5. Process/procedure in place for obtaining generation commitment information and load forecast.

4.6. Process/procedure in place to provide day-ahead hourly dispatch pattern to the Reliability Authority.

4.7. Process/procedure and tools in place identifying the analysis and approval process for interchange transactions into and out of the balancing area with respect to the ramping requirements of generation.

4.8. Process/procedure in place for data acquisition to ensure resources/demand balance in compliance to NERC Standards.

4.9. Process/procedure in place for data acquisition and performance of analyses with regards to contingency reserves, load-following, frequency response, and other applicable Balancing Authority Interconnected Operating Services.

4.10. Process/procedure in place for calculating and reporting performance of NERC

[1] An agreement is defined as a contract or other document delineating an arrangement that expresses assent by two or more parties to the same object. This arrangement determines a course of action to be followed by all parties involved in the situation. The key components of the agreement must identify the ability, intent, and authority of the parties. The requirement for these agreements can be satisfied in a variety of ways, including but not limited to: contracts, designation of authority documents, policies, procedures.

Standards.

4.11. Process/procedure in place for providing data for all required NERC and Regional surveys.

4.12. Process/procedure to perform energy accounting for inadvertent accumulations.

5. Emergency Operations

5.1. Process/procedure in place that defines the responsibilities and actions of the Balancing Authority with regards to emergency operations.

5.2. Plan in place that ensures continued operation during abnormal and emergency conditions due to the loss of facilities.

Reliability Functions

The Standard will Apply to the Following Functions (Check all that apply)		
☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority Area. This is the highest reliability authority.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability and Market Interface Principles (check all that apply)	
1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.	☒
2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand	☒
3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably	☒
4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented	☒
5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems	☒
6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions	☒
7. The reliability of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis	☒
The proposed Standard must comply with all of the following Market Interface Principles	☒
Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
An Organization Standard shall not give any market participant an unfair competitive advantage	
An Organization Standard shall neither mandate nor prohibit any specific market structure	
An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

Related Standards, Function Certification Requirements or Business Practices

Standard No.	***Explanation***

Related SARs

SAR ID	***Explanation***

Regional Differences

These Regional differences have been identified by individuals or groups through comments received in the SAR postings. The intent is not to comment on these differences at this time, but rather after these comments have been forwarded to the Standard Drafting Team for their inclusion in the Standard. Ample opportunity will be available to comment during the Standard development process.

Region	***Explanation***
ECAR	
ERCOT	Add Qualified Scheduling Entities to the list of possible Certification Review Team members in step 10 of the Certification Process.
FRCC	FRCC requires their own confidentiality agreement in addition to the NERC agreement. In addition, FRCC's Security Process (Reliability Plan) has other requirements for tools, etc. that must be met.
MAAC	
MAIN	
MAPP	
NPCC	Differences for Markets vs. regulated areas may impact this SAR.
SERC	
SPP	
WSCC	WECC has additional data and Reliability Management System confidentiality agreements that may or may not be included

SAR DT Members

Gerry Burrows, Chairman

Pat Everly, Secretary

Larry Alderink

Don Badley

Alan Boesch

Lucius Burris

David Little

Norb Mizwicki

Don Reichenbach

Richard Sikes

Steven Wallace

Joe Willson

Daniel Zaragoza

Standard Authorization Request Form

Name of Proposed Standard	Certification of the Interchange Authority Function
Request Date	October 7, 2002
Authorized for Posting	November 20, 2002
SAR ID#	IA_CERTIFICATION_01_03

SAR Requestor Information		***SAR Type***	
Name	Organization Certification Task Force	☒	1. New Standard
Primary Contact	Gerry Burrows	☐	2. Revision to existing Standard or
Telephone	816-654-1183	☐	3. Withdrawal of existing Standard
e-mail	gerry.burrows@kcpl.com	☐	4. Urgent Action

Purpose/Industry Need of Standard

To ensure that each entity that wants to be recognized as an Interchange Authority has the capability of performing the responsibilities assigned to the Interchange Authority function.

Brief Description of New Standard or Revision to Existing Standard

Each entity that wants to be recognized as an Interchange Authority shall demonstrate that it has the processes, procedures, tools and agreements in place to demonstrate that it has the capability of performing the responsibilities assigned to the Interchange Authority Function.

Detailed Description of New Standard or Revision to Existing Standard

Summary

The primary steps in the Interchange Authority Certification Process, and the entity responsible for each step, are as follows:

- Initiation of Process – Entity seeking certification (the "Applicant")
- Provision of criteria, process, documentation, etc. – Region
- Formation of Certification Review Team – Region
- Data collection – Region
- Data review – Region (Review Team)
- Site visit – Region (Review Team)
- Recommendation – Region (Review Team)
- Certification and Authority to operate – Region
- Notification of authority to operate – NERC

Interchange Authority Certification Process

1. Single IA in a Single Region

An entity seeking certification as an Interchange Authority (the "Applicant") will initiate the certification process by making a formal request to the Regional Manager in the Region where the Applicant plans to operate. A copy of the request will also be sent to the NERC Director-Compliance.

Single IA in multiple Regions

An entity seeking certification as an Interchange Authority (the "Applicant") in multiple Regions will initiate the certification process by making a formal request to one of the Regional Managers of a Region where the Applicant plans to operate and copy all other Regional Managers of those Regions within which the Applicant will operate. A copy of the request will also be sent to the NERC Director-Compliance.

2. Single IA in a Single Region

The NERC Region in which the Applicant plans to operate will be responsible for conducting the formal review process and awarding of certification.

Single IA in multiple Regions

In situations where an IA crosses Regional boundaries, all affected Regions shall participate in the certification process. The affected Regions shall identify one of the affected Regions as the Lead Region. The Lead Region shall be responsible for coordinating the formal review process and the awarding of certification in concurrence with the other affected Regions.

3. A timeline, including specific milestones, shall be agreed to by the Applicant and the Regional or

Lead Regional Council. The NERC Interchange Authority Certification Procedure and certification recommendation is expected to be completed within nine months of the date when the initial request was received by the Regional Manager.

4. The Region or Lead Region will notify all appropriate parties and provide each with the necessary information regarding the Interchange Authority's request for certification, the certification process, and the duties expected from each entity.

5. The Applicant must register in the NERC Master Registry. Registration stays on hold until certification is granted or denied.

6. NERC/Regional Staff will begin the process of making any necessary modeling/software changes. The Applicant and Region will supply necessary information to NERC.

7. The Region or Lead Region will provide questionnaires and related documents that will be used by all entities involved in the certification process. These questionnaires and related documents will be used to address the Applicant's capabilities and actions as they relate to established Interchange Authority requirements. The following list of entities will be recipients of the questionnaires and related documents as each is a source of certification information and data:

- Applicant (i.e. entity seeking Interchange Authority certification)
- Balancing Authorities and Transmission Service Providers it intends to operate with.
- Reliability Authorities
- Other Interchange Authorities

8. The Region or Lead Region will provide expectations and standards regarding confidentiality and retention of all data reporting, completed questionnaires and forms, reports and recommendations associated with the documentation it provides and receives.

9. The Region or Lead Region will assemble a Certification Review Team charged with the responsibility of determining if the Applicant meets NERC's Interchange Authority Criteria. The Region or Lead Region and the Applicant will agree on the Review Team members before the commencement of the review process. The Review Team will subject themselves to confidentiality agreements for any data or information that is made available to them through the certification review process.

10. The Review Team will consist of a minimum of three individuals. The selected individuals will represent at least three of the categories listed below:

- Interchange Authority
- Balancing Authority
- Reliability Authority
- Transmission Operator
- Transmission Service Provider
- Purchasing Selling Entity
- Regional Compliance Committee member
- Regional Operating Committee member
- Representative from NERC Staff
- Representative from Regional Staff

- Representative from another NERC Region
- Representative from an RTO, when applicable

Review team members cannot be employees of the applicant or any of its affiliates.

Review processes that involve an entity that is performing a function across Regional boundaries shall have a review team that consists of at least one member from each of the affected Regions. These representatives will be selected by the individual Regions that they represent and not by the Lead Region. Regional representation is still subject to Applicant approval. Remaining review team members must represent at least two of the remaining categories.

In the alternative, the Region may elect, with applicant agreement, to engage a completely independent review team.

11. The Review Team will report its initial findings to the Applicant and to the Region(s) based on the information obtained through the initial application and questionnaires. The review Team will request any additional information before making an on-site visit.

12. The Review Team will conduct at least one on-site visit to the Applicant's facility. During the visit, the Review Team will:

- Review with the Applicant the data collected through the questionnaires,
- Interview the Applicant's operations and management personnel,
- Inspect the Applicant's facilities and equipment, and
- Review all necessary documents and data.

13. The Review Team will identify any deficiencies (to both the Applicant and to the Region) that must be resolved prior to the review team making their final recommendation. The Review Team will review any follow-up work required by the Applicant until a certification recommendation is made.

14. The Review Team will formulate a certification recommendation based on: data collected and validated from the questionnaires; and from observations and information collected during an on-site visit to the Applicant's facility. The Review Team will support its recommendation through the production of an evaluation review template and a formal report. All members of the review team will have an equal voice in the certification recommendation.

15. Single IA in a single Region

The certification recommendation from the Review Team will be presented to the appropriate Regional committee(s). The certification recommendation is made by the review team and then approved or disapproved by the Region.

Single IA in multiple Regions

The certification recommendation will be presented to the appropriate Regional committee(s) of all the affected Regions by the Review Team. The certification recommendation is then approved or disapproved by all of the affected Regions. The Lead Region will be responsible for verifying the Regional approvals prior to awarding certification.

16. The Region or Lead Region will notify the Applicant of the certification decision. The Region or Lead Region (in consultation with the affected Regions) may award or deny the Applicant's certification as an Interchange Authority. As an alternative, the Region or Lead Region (in consultation with the affected Regions) may grant 'pending certification' to the applicant. The pending certification shall be granted for a period of time not longer than 180 days. Pending certification, does not grant operation as an Interchange Authority. If the Applicant fails to meet

the conditions set by the Region(s), within the granted timeframe, the Applicant's certification will be deemed to be the same as denied. If the Applicant meets the conditions set by the Region(s), within the granted timeframe, the Region or Lead Region (in consultation with the affected Regions) must respond to the Applicant's notification of completion of requirements within 30 days.

17. After the Region or Lead Region has approved the Applicant as an Interchange Authority, the Region or Lead Region will notify NERC Staff, who in turn, will notify all of the necessary entities as to the date that the Applicant may begin its Interchange Authority operation. Interchange Authority operation shall not begin before the agreed upon date and must commence operation within 12 months of certification. Failure to begin operation within the 12-month period will require the applicant to re-apply for certification.

18. If the Region or Lead Region denies certification, it shall provide the Applicant with a written report containing specific reasons for the denial. If the Applicant disagrees with the Region's(s') decision, it can initiate the Regional ADR process within 60 days of the date of the written denial. If the Applicant fails to initiate the ADR process within the 60-day time limit as identified in the previous step, it may reapply for certification after 90 days from the date of written denial.

De-certification Process

This section describes the process that will be used for the de-certification of an Interchange Authority when the entity does not wish to continue performing the Interchange Authority function and has arranged for a replacement entity to assume its Interchange Authority responsibilities.

1. The Interchange Authority requesting de-certification notifies the Region(s) it operates in that it wishes to be decertified and names the Interchange Authority(ies) that will be assuming its Interchange Authority responsibilities. If the Interchange Authority(ies) assuming the responsibilities is in a different Region, then a Lead Region will be designated and all Regions will be involved in the process.

2. The Region or Lead Region contacts the Interchange Authority(ies) that is to assume the additional Interchange Authority responsibilities to begin the certification process.

3. After the Region or Lead Region has certified the Interchange Authority(ies) assuming additional responsibilities, the Region or Lead Region will notify the Interchange Authority desiring de-certification and NERC staff of the date the Interchange Authority will cease operation.

4. NERC will notify the appropriate entities of this date.

Interchange Authority Certification Criteria

Introduction

These Criteria establish the requirements for certification as a NERC Interchange Authority. They are based on NERC Reliability Standards, NERC Operating Policies and Planning Standards, and the NERC Functional Model NERC Policies and Standards applicable to the Interchange Authority function must be adhered to until they are replaced by Reliability Standards or retired.

Definition of the Interchange Authority Function

Authorizes valid transactions and ensures balanced Interchange Schedules.

Certification Criteria

1. **Confirmation by Regional Council.** To be recognized as a NERC-Certified Interchange Authority, the entity must be reviewed and confirmed by the Regional Council(s) in which the entity operates.

2. **Agreements.** Agreements[1] must be in place defining the responsibilities and authority of the Interchange Authority with respect to all applicable Reliability Authorities, Balancing Authorities, Transmission Service Providers, and all other functional entities with which it provides a service. Agreements shall address both normal and emergency operations.

3. **Personnel**

3.1. Must have NERC-certified system operators performing the Interchange Authority responsibilities 24 hours a day, 7 days a week.

4. **Organization**

4.1. Documentation identifying that the organization has signed the NERC Confidentiality Agreement.

4.2. Documentation identifying that the Interchange Authority personnel are aware of their obligations and responsibilities under the NERC Confidentiality Agreement.

4.3. Documentation identifying the code of conduct for personnel performing the Interchange Authority responsibilities.

4.4. Documentation identifying that the Interchange Authority personnel are aware of their obligations and responsibilities under the code of conduct.

5. **Data Acquisition and System Analysis**

5.1. Process/procedure and tools in place for ensuring valid and balanced interchange schedules.

5.2. Process/procedure and tools in place for authorizing the implementation of interchange transactions.

5.3. Process/procedure and tools in place for communicating the implementation, cancellation, or curtailment of scheduled interchange transactions.

5.4. Process/procedure and tools in place for providing interchange transaction information for the reliability assessment.

5.5. Process/procedure and tools in place for the accounting of scheduled interchange transactions for specific Balancing Authorities.

5.6. Process/procedure and tools in place for compliance with all applicable NERC reliability standards.

6. **Emergency Operations**

[1] An agreement is defined as a contract or other document delineating an arrangement that expresses assent by two or more parties to the same object. This arrangement determines a course of action to be followed by all parties involved in the situation. The key components of the agreement must identify the ability, intent, and authority of the parties. The requirement for these agreements can be satisfied in a variety of ways, including but not limited to: contracts, designation of authority documents, policies, procedures.

6.1.	Plan in place that ensures continued operation during abnormal and emergency conditions due to the loss of facilities.

Reliability Functions

The Standard will Apply to the Following Functions (Check all that apply)		
☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority Area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☒	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability and Market Interface Principles (check all that apply)	
1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.	☒
2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand	☒
3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably	☒
4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented	☐
5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems	☒
6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions	☒
7. The reliability of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis	☐
The proposed Standard must comply with all of the following Market Interface Principles	☒
Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
An Organization Standard shall not give any market participant an unfair competitive advantage	
An Organization Standard shall neither mandate nor prohibit any specific market structure	
An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

Related Standards, Function Certification Requirements or Business Practices

Standard No.	***Explanation***

Related SARs

SAR ID	***Explanation***

Regional Differences

Region	*Explanation*
ECAR	
ERCOT	
FRCC	FRCC requires their own confidentiality agreement in addition to the NERC agreement. In addition, FRCC's Security Process (Reliability Plan) has other requirements for tools, etc. that must be met. Also, NERC can not set a requirement for the IA will preempt any state jurisdictional requirements.
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WSCC	WECC has additional data and Reliability Management System confidentiality agreements that may or may not be included.

SAR DT Members

Gerry Burrows, Chairman

Pat Everly, Secretary

Larry Alderink

Don Badley

Alan Boesch

Lucius Burris

David Little

Norb Mizwicki

Don Reichenbach

Richard Sikes

Steven Wallace

Joe Willson

Daniel Zaragoza

Standard Authorization Request Form

Name of Proposed Standard	Certification of the Reliability Authority Function
Request Date	October 7, 2002
Authorized for Posting	November 20, 2002
SAR ID#	RA_CERTIFICATION_01_03

SAR Requestor Information		***SAR Type***	
Name	Organization Certification Task Force	☒	1. New Standard
Primary Contact	Gerry Burrows	☐	2. Revision to existing Standard or
Telephone	816-654-1183	☐	3. Withdrawal of existing Standard
e-mail	gerry.burrows@kcpl.com	☐	4. Urgent Action

Purpose/Industry Need of Standard

To ensure that each entity that wants to be recognized as a Reliability Authority has the capability of performing the responsibilities assigned to the Reliability Authority function.

Brief Description of New Standard or Revision to Existing Standard

Each entity that wants to be recognized as a Reliability Authority shall demonstrate that it has the processes, procedures, tools and agreements in place to demonstrate that it has the capability of performing the responsibilities assigned to the Reliability Function.

Detailed Description of New Standard or Revision to Existing Standard

Summary

The primary steps in the Reliability Authority Certification Process, and the entity responsible for each step, are as follows:

- Initiation of Process – Entity seeking certification (the "Applicant")
- Provision of criteria, process, documentation, etc. – Region
- Formation of Certification Review Team – Region
- Data collection – Region
- Data review – Region (Review Team)
- Site visit – Region (Review Team)
- Recommendation – Region (Review Team)
- Certification and Authority to operate – Region
- Notification of authority to operate – NERC

Reliability Authority Certification Process

1. Single RA in a Single Region

An entity seeking certification as a Reliability Authority (the "Applicant") will initiate the certification process by making a formal request to the Regional Manager in the Region where the Applicant plans to operate a Reliability area. A copy of the request will also be sent to the NERC Director-Compliance.

Single RA in Multiple Regions

An entity seeking certification as a Reliability Authority (the "Applicant") in multiple Regions will initiate the certification process by making a formal request to one of the Regional Managers of a Region where the Applicant plans to operate a Reliability area and copy all other Regional Managers of those Regions within which the Applicant will operate. A copy of the request will also be sent to the NERC Director-Compliance.

2. Single RA in a Single Region

The NERC Region in which the Applicant plans to operate will be responsible for conducting the formal review process and the awarding of certification.

Single RA in multiple Regions

In situations where a RA crosses Regional boundaries, all affected Regions shall participate in the certification process. The affected Regions shall identify one of the affected Regions as the Lead Region. The Lead Region shall be responsible for coordinating the formal review process and the awarding of certification in concurrence with the other affected Regions.

3. A timeline, including specific milestones, shall be agreed to by the Applicant and the Regional or Lead Regional Council. The NERC Reliability Authority Certification Procedure and certification recommendation is expected to be completed within nine months of the date when the initial request was received by the Regional Manager.

4. The Region or Lead Region will notify all appropriate parties and provide each with the necessary information regarding the Reliability Authority's request for certification, the certification process, and the duties expected from each entity.

5. The Applicant must register in the NERC Master Registry. Registration stays on hold until certification is granted or denied.

6. NERC/Regional Staff will begin the process of making any necessary modeling/software changes. The Applicant and Region will supply necessary information to NERC.

7. The Region or Lead Region will provide questionnaires and related documents that will be used by all entities involved in the certification process. These questionnaires and related documents will be used to address the Applicant's capabilities and actions as they relate to established Reliability Authority requirements. The following list of entities will be recipients of the questionnaires and related documents as each is a source of certification information and data:

- Applicant (i.e. entity seeking Reliability Authority certification)
- Balancing Authorities and Transmission Operators within the Applicant's Reliability Area
- Reliability Authorities adjacent to the applicant
- Other Regional Council(s), when applicable

8. The Region or Lead Region will provide expectations and standards regarding confidentiality and retention of all data reporting, completed questionnaires and forms, reports and recommendations associated with the documentation it provides and receives.

9. The Region or Lead Region will assemble a Certification Review Team charged with the responsibility of determining if the Applicant meets NERC's Reliability Authority Criteria. The Region or Lead Region and the Applicant will agree on the Review Team members before the commencement of the review process. The Review Team will subject themselves to confidentiality agreements for any data or information that is made available to them through the certification review process.

10. The Review Team will consist of a minimum of three individuals. The selected individuals will represent at least three of the categories listed below:

- Interchange Authority
- Balancing Authority
- Reliability Authority
- Transmission Operator
- Regional Compliance Committee member
- Regional Operating Committee member
- Representative from NERC Staff
- Representative from Regional Staff
- Representative from another NERC Region

- Representative from an RTO, when applicable

Review team members cannot be employees of the applicant or any of its affiliates.

Review processes that involve an entity that is performing a function across Regional boundaries shall have a review team that consists of at least one member from each of the affected Regions. These representatives will be selected by the individual Regions that they represent and not by the Lead Region. Regional representation is still subject to Applicant approval. Remaining review team members must represent at least two of the remaining categories.

In the alternative, the Region(s) may elect, with applicant agreement, to engage a completely independent review team.

11. The Review Team will report its initial findings to the Applicant and to the Region(s) based on the information obtained through the initial application and questionnaires. The review Team will request any additional information before making an on-site visit.

12. The Review Team will conduct at least one on-site visit to the Applicant's control center facility. During the visit, the Review Team will:

- Review with the Applicant the data collected through the questionnaires,
- Interview the Applicant's operations and management personnel,
- Inspect the Applicant's facilities and equipment, and
- Review all necessary documents and data.

13. The Review Team will identify any deficiencies (to both the Applicant and to the Region(s)) that must be resolved prior to the review team making their final recommendation. The Review Team will review any follow-up work required by the Applicant until a certification recommendation is made.

14. The Review Team will formulate a certification recommendation based on: data collected and validated from the questionnaires; and from observations and information collected during an on-site visit to the Applicant's facility. The Review Team will support its recommendation through the production of an evaluation review template and a formal report. All members of the review team will have an equal voice in the certification recommendation.

15. Single RA in Single Region

The certification recommendation from the Review Team will be presented to the appropriate Regional committee(s). The certification recommendation is made by the review team and then approved or disapproved by the Region.

Single RA in multiple Regions

The certification recommendation will be presented to the appropriate Regional committee(s) of all the affected Regions by the Review Team. The certification recommendation is then approved or disapproved by all of the affected Regions. The Lead Region will be responsible for verifying the Regional approvals prior to awarding certification.

16. The Region or Lead Region will notify the Applicant of the certification decision. The Region or Lead Region (in consultation with the affected Regions) may award or deny the Applicant's certification as a Reliability Authority. As an alternative, the Region or Lead Region (in consultation with the affected Regions) may grant 'pending certification' to the applicant. The pending certification shall be granted for a period of time not longer than 180 days. Pending certification, does not grant operation as a Reliability Authority. If the Applicant fails to meet the conditions set by the Region(s), within the granted timeframe, the Applicant's certification will be deemed to be the same as denied. If the Applicant meets the conditions set by the Region(s),

within the granted timeframe, the Region or Lead Region (in consultation with the affected Regions) must respond to the Applicant's notification of completion of requirements within 30 days.

17. After the Region or Lead Region has approved the Applicant as a Reliability Authority, ~~they~~ the Region or Lead Region will notify NERC Staff, who in turn, will notify all of the necessary entities as to the date that the Applicant may begin its Reliability Authority operation. Reliability Authority operation shall not begin before the agreed upon date and must commence operation within 12 months of certification. Failure to begin operation within the 12-month period will require the applicant to re-apply for certification.

18. If the Region or Lead Region denies certification, it shall provide the Applicant with a written report containing specific reasons for the denial. If the Applicant disagrees with the Region's(s') decision, it can initiate the Regional ADR process within 60 days of the date of the written denial. If the Applicant fails to initiate the ADR process within the 60-day time limit as identified in the previous step, it may reapply for certification after 90 days from the date of written denial.

De-certification Process

This section describes the process that will be used for the de-certification of a Reliability Authority when the entity does not wish to continue performing the Reliability Authority function and has arranged for a replacement entity to assume its Reliability Authority responsibilities.

1. The Reliability Authority requesting de-certification notifies the Region(s) it operates in that it wishes to be decertified and names the Reliability Authority(ies) that will be assuming its Reliability Authority responsibilities. If the Reliability Authority(ies) assuming the responsibilities is in a different Region, then a Lead Region will be designated and all Regions will be involved in the process.

2. The Region or Lead Region contacts the Reliability Authority(ies) that is to assume the additional Reliability Authority responsibilities to begin the certification process.

3. After the Region or Lead Region has certified the Reliability Authority(ies) assuming additional responsibilities, the Region or Lead Region will notify the Reliability Auth[illegible]e-certification and NERC staff of the date the Re[illegible] Authority will cease operation.

Change 'notice' to 'notify'

4. NERC will ~~notice~~ notify the appropriate entities of this date.

Reliability Authority Certification Criteria

Introduction

These Criteria establish the requirements for certification as a NERC Reliability Authority. They are based on NERC Reliability Standards, NERC Operating Policies and Planning Standards, and the NERC Functional Model. NERC Policies and Standards applicable to the Reliability Authority function must be adhered to until they are replaced by Reliability Standards or retired.

Definition of the Reliability Authority Function

Ensures the reliability of the bulk power transmission system within its Reliability Authority Area.

Certification Criteria

1. Confirmation by Regional Council. To be recognized as a NERC-Certified RELIABILITY AUTHORITY, the entity must be reviewed and confirmed by the Regional Council(s) in which the entity operates.

2. Agreements. Agreements[1] must be in place defining the responsibilities and authority of the RELIABILITY AUTHORITY with respect to all Balancing Authorities, Interchange Authorities, Transmission Operators, Transmission Service Provider and all other applicable functional entities within the reliability area and with other Reliability Authorities. Agreements shall address both normal and emergency operations.

3. Personnel

3.1. Must have NERC-certified system operators performing the Reliability Authority responsibilities 24 hours a day, 7 days a week.

4. Organization

4.1. Documentation identifying that the organization has signed the NERC Confidentiality Agreement.

4.2. Documentation identifying that the Reliability Authority personnel are aware of their obligations and responsibilities under the NERC Confidentiality Agreement.

4.3. Documentation identifying the code of conduct for personnel performing the Reliability Authority responsibilities.

4.4. Documentation identifying that the Reliability Authority personnel are aware of their obligations and responsibilities under the code of conduct.

5. Data Acquisition and System Analysis

5.1. Must have the ability to monitor its reliability area with real-time data. (e.g., demand, volts, VArs, frequency, interchange tie flows, reserves, ACE, equipment status, transmission line flows, etc.)

5.2. Process/procedure in place to receive day-ahead hourly dispatch pattern from the Balancing Authority.

5.3. Process/procedure in place to receive interchange transaction information from the Interchange Authority.

5.4. Process/procedure in place for collecting transmission owners' equipment ratings.

5.5. Process/procedure and tools in place to perform real-time and contingency reliability analyses.

5.6. Process/procedure and tools in place to coordinate and approve transmission outages from a reliability perspective.

5.7. Process/procedure and tools in place to collect and analyze generation outages from a reliability perspective.

5.8. Process/procedure in place with other Reliability Authorities to coordinate day-ahead analyses and to implement real-time actions.

[1] An agreement is defined as a contract or other document delineating an arrangement that expresses assent by two or more parties to the same object. This arrangement determines a course of action to be followed by all parties involved in the situation. The key components of the agreement must identify the ability, intent, and authority of the parties. The requirement for these agreements can be satisfied in a variety of ways, including but not limited to: contracts, designation of authority documents, policies, procedures.

5.9. Process/procedure in place defining the analysis and approval process for interchange transactions into, out of, and through the reliability area.

5.10. Process/procedure and tools in place to develop real-time operating reliability limits.

5.11. Process/procedure in place that define the actions to be taken for maintaining reliability.

5.12. Process/procedure and tools in place for compliance with all applicable NERC reliability standards.

6. Emergency Operations

6.1. Process/procedure in place that defines the coordination and implementation of emergency operations within or on an area-wide basis.

6.2. Process/procedure in place that defines the coordination and implementation of system restoration operations within or on an area-wide basis.

6.3. Plan in place that ensures continued operation during abnormal and emergency conditions due to the loss of facilities.

7. Security

7.1. Process/procedure in place for collection and dissemination of information with regards to physical and cyber security in accordance with NERC reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions (Check all that apply)		
☒	Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability and Market Interface Principles (check all that apply)	
1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.	☒
2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand	☐
3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably	☒
4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented	☒
5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems	☒
6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions	☒
7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis	☒
The proposed Standard must comply with all of the following Market Interface Principles	☒
Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
An Organization Standard shall not give any market participant an unfair competitive advantage	
An Organization Standard shall neither mandate nor prohibit any specific market structure	
An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

Related Standards, Function Certification Requirements or Business Practices

Standard No.	***Explanation***

Related SARs

SAR ID	***Explanation***

Regional Differences

Region	*Explanation*
ECAR	
ERCOT	
FRCC	FRCC requires their own confidentiality agreement in addition to the NERC agreement. In addition, FRCC's Security Process (Reliability Plan) has other requirements for tools, etc. that must be met. Also, NERC can not set a requirement for the RA will preempt any state jurisdictional requirements. FRCC contracts with an agent to perform the services of the Reliability Authority for its Region. FRCC plans to continue this practice in the future, and is unclear how the steps in the Certification Process would apply to the FRCC region. FRCC may want to serve on the Review Team but under Step 10 of the Certification Process, this would not be permitted without a Regional Difference. (Step 10 includes the following language: "Review team members cannot be employees of the applicant or any of its affiliates.") A regional difference may be required to accommodate having FRCC serve on the review team in the situation where FRCC is applying for certification as an RA.
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WSCC	WECC Reliability Coordinator Empowerment agreements may, or may not, come into play here - this is a placeholder for further development if necessary. The Certification Process should include making changes to the TDF for the WECC Region.

SAR DT Members
Gerry Burrows, Chairman
Pat Everly, Secretary
Larry Alderink
Don Badley
Alan Boesch
Lucius Burris
David Little
Norb Mizwicki
Don Reichenbach
Richard Sikes
Steven Wallace
Joe Willson
Daniel Zaragoza

Standard Authorization Request Form

Name of Proposed Standard	Certification of the Transmission Operator Function
Request Date	October 7, 2002
Authorized for Posting	November 20, 2002
SAR ID#	TOP_CERTIFICATION_01_03

SAR Requestor Information		***SAR Type***	
Name	Organization Certification Task Force	☒	1. New Standard
Primary Contact	Gerry Burrows	☐	2. Revision to existing Standard or
Telephone	816-654-1183	☐	3. Withdrawal of existing Standard
e-mail	gerry.burrows@kcpl.com	☐	4. Urgent Action

Purpose/Industry Need of Standard

To ensure that each entity that wants to be recognized as a Transmission Operator has the capability of performing the responsibilities assigned to the Transmission Operator function.

Brief Description of New Standard or Revision to Existing Standard

Each entity that wants to be recognized as a Transmission Operator shall demonstrate that it has the processes, procedures, tools and agreements in place to demonstrate that it has the capability of performing the responsibilities assigned to the Reliability Function.

Detailed Description of New Standard or Revision to Existing Standard

Summary

The primary steps in the Transmission Operator Certification Process, and the entity responsible for each step, are as follows:

- Initiation of Process – Entity seeking certification (the "Applicant")
- Provision of criteria, process, documentation, etc. – Region
- Formation of Certification Review Team – Region
- Data collection – Region
- Data review – Region (Review Team)
- Site visit – Region (Review Team)
- Recommendation – Region (Review Team)
- Certification and Authority to operate – Region
- Notification of authority to operate – NERC

Transmission Operator Certification Process

1. Single TOP in a Single Region

An entity seeking certification as a Transmission Operator (the "Applicant") will initiate the certification process by making a formal request to the Regional Manager in the Region where the Applicant plans to operate. A copy of the request will also be sent to the NERC Director-Compliance.

Single TOP in Multiple Regions

An entity seeking certification as a Transmission Operator (the "Applicant") in multiple Regions will initiate the certification process by making a formal request to one of the Regional Managers of a Region where the Applicant plans to operate and copy all other Regional Managers of those Regions within which the Applicant will operate. A copy of the request will also be sent to the NERC Director-Compliance.

2. Single TOP in a Single Region

The NERC Region in which the Applicant plans to operate will be responsible for conducting the formal review process and awarding of certification.

Single TOP in multiple Regions

In situations where a TOP crosses Regional boundaries, all affected Regions shall participate in the certification process. The affected Regions shall identify one of the affected Regions as the Lead Region. The Lead Region shall be responsible for coordinating the formal review process and the awarding of certification in concurrence with the other affected Regions.

3. A timeline, including specific milestones, shall be agreed to by the Applicant and the Regional or Lead Regional Council. The NERC Transmission Operator Certification Procedure and certification recommendation is expected to be completed within nine months of the date when the initial request was received by the Regional Manager.

4. The Region or Lead Region will notify all appropriate parties and provide each with the necessary information regarding the Transmission Operator's request for certification, the certification process, and the duties expected from each entity.

5. The Applicant must register in the NERC Master Registry. Registration stays on hold until certification is granted or denied

6. NERC/Regional Staff will begin the process of making any necessary modeling/software changes. The Applicant and Region will supply necessary information to NERC.

7. The Region or Lead Region will provide questionnaires and related documents that will be used by all entities involved in the certification process. These questionnaires and related documents will be used to address the Applicant's capabilities and actions as they relate to established Transmission Operator requirements. The following list of entities will be recipients of the questionnaires and related documents as each is a source of certification information and data:

- Applicant (i.e. entity seeking Transmission Operator certification)
- Its Balancing Authorities and Reliability Authorities
- Its Transmission Service Provider(s)
- All Adjacent Transmission Operators

8. The Region or Lead Region will provide expectations and standards regarding confidentiality and retention of all data reporting, completed questionnaires and forms, reports and recommendations associated with the documentation it provides and receives.

9. The Region or Lead Region will assemble a Certification Review Team charged with the responsibility of determining if the Applicant meets NERC's Transmission Operator Criteria. The Region or Lead Region and the Applicant will agree on the Review Team members before the commencement of the review process. The Review Team will subject themselves to confidentiality agreements for any data or information that is made available to them through the certification review process.

10. The Review Team will consist of a minimum of three individuals. The selected individuals will represent at least three of the categories listed below:

- Interchange Authority
- Balancing Authority
- Reliability Authority
- Transmission Operator
- Regional Compliance Committee member
- Regional Operating Committee member
- Representative from NERC Staff
- Representative from Regional Staff
- Representative from another NERC Region

- Representative from an RTO, when applicable

Review team members cannot be employees of the applicant or any of its affiliates.

Review processes that involve an entity that is performing a function across Regional boundaries shall have a review team that consists of at least one member from each of the affected Regions. These representatives will be selected by the individual Regions that they represent and not by the Lead Region. Regional representation is still subject to Applicant approval. Remaining review team members must represent at least two of the remaining categories.

In the alternative, the Region may elect, with applicant agreement, to engage a completely independent review team.

11. The Review Team will report its initial findings to the Applicant and to the Region(s) based on the information obtained through the initial application and questionnaires. The review Team will request any additional information before making an on-site visit.

12. The Review Team will conduct at least one on-site visit to the Applicant's control center facility. During the visit, the Review Team will:

- Review with the Applicant the data collected through the questionnaires,
- Interview the Applicant's operations and management personnel,
- Inspect the Applicant's facilities and equipment, and
- Review all necessary documents and data.

13. The Review Team will identify any deficiencies (to both the Applicant and to the Region(s)) that must be resolved prior to the review team making their final recommendation. The Review Team will review any follow-up work required by the Applicant until a certification recommendation is made.

14. The Review Team will formulate a certification recommendation based on: data collected and validated from the questionnaires; and from observations and information collected during an on-site visit to the Applicant's facility. The Review Team will support its recommendation through the production of an evaluation review template and a formal report. All members of the review team will have an equal voice in the certification recommendation.

15. Single TOP in Single Region

The certification recommendation from the Review Team will be presented to the appropriate Regional committee(s). The certification recommendation is made by the review team and then approved or disapproved by the Region.

Single TOP in multiple Regions

The certification recommendation will be presented to the appropriate Regional committee(s) of all the affected Regions by the Review Team. The certification recommendation is then approved or disapproved by all of the affected Regions. The Lead Region will be responsible for verifying the Regional approvals prior to awarding certification.

16. The Region or Lead Region will notify the Applicant of the certification decision. The Region or Lead Region (in consultation with the affected Regions) may award or deny the Applicant's certification as a Transmission Operator. As an alternative, the Region or Lead Region (in consultation with the affected Regions) may grant 'pending certification' to the applicant. The pending certification shall be granted for a period of time not longer than 180 days. Pending certification, does not grant operation as a Transmission Operator. If the Applicant fails to meet the conditions set by the Region(s), within the granted timeframe, the Applicant's certification

will be deemed to be the same as denied. If the Applicant meets the conditions set by the Region or Lead Region(in consultation with the affected Regions), within the granted timeframe, the Region(s) must respond to the Applicant's notification of completion of requirements within 30 days.

17. After the Region or Lead Region has approved the Applicant as a Transmission Operator, the Region or Lead Region will notify NERC Staff, who in turn, will notify all of the necessary entities as to the date that the Applicant may begin its Transmission Operator operation. Transmission Operator operation shall not begin before the agreed upon date and must commence operation within 12 months of certification. Failure to begin operation within the 12-month period will require the applicant to re-apply for certification.

18. If the Region or Lead Region denies certification, it shall provide the Applicant with a written report containing specific reasons for the denial. If the Applicant disagrees with the Region's decision, it can initiate the Regional ADR process within 60 days of the date of the written denial. If the Applicant fails to initiate the ADR process within the 60-day time limit as identified in the previous step, it may reapply for certification after 90 days from the date of written denial.

De-certification Process

This section describes the process that will be used for the de-certification of a Transmission Operator when the entity does not wish to continue performing the Transmission Operator function and has arranged for a replacement entity to assume its Transmission Operator responsibilities.

1. The Transmission Operator requesting de-certification notifies the Region(s) it operates in that it wishes to be decertified and names the Transmission Operator (s) that will be assuming its Transmission Operator responsibilities. If the Transmission Operator (s) assuming the responsibilities is in a different Region, then a Lead Region will be designated and all Regions will be involved in the process.

2. The Region or Lead Region contacts the Transmission Operator (s) that is to assume the additional Transmission Operator responsibilities to begin the certification process.

3. After the Region or Lead Region has certified the Transmission Operator(s) assuming additional responsibilities, the Region or Lead Region will notify the Transmission Operator desiring de-certification and NERC staff of the date the Transmission Operator will cease operation.

4. NERC will notify the appropriate entities of this date.

Transmission Operator Criteria

Introduction

These Criteria establish the requirements for certification as a NERC Transmission Operator. They are based on existing NERC Reliability Standards, NERC Operating Policies and Planning Standards, and the NERC Functional Model. NERC Policies and Standards applicable to the Transmission Operator function must be adhered to until they are replaced by Reliability Standards or retired.

Definition of the Transmission Operator Function

Monitors and assesses local reliability, operates the transmission facilities, and executes switching orders

in support of the Reliability Authority.

Certification Criteria

1. **Confirmation by Regional Council.** To be recognized as a NERC-Certified Transmission Operator, the entity must be reviewed and confirmed by the Regional Council(s) in which the entity operates.

2. **Agreements.** Agreements must be in place defining the responsibilities and authority of the Transmission Operator with the Reliability Authorities, Transmission Service Providers, Distribution Providers, and all other applicable functional entities with which its facilities connect. Agreements shall address both normal and emergency operations.

3. **Personnel**

3.1. Must have NERC-certified system operators performing the Transmission Operator responsibilities 24 hours a day, 7 days a week.

4. **Organization**

4.1. Documentation identifying that the organization has signed the NERC Confidentiality Agreement.

4.2. Documentation identifying that the Transmission Operator personnel are aware of their obligations and responsibilities under the NERC Confidentiality Agreement.

5. **Data Acquisition and System Analysis**

5.1. Must have the ability to monitor its area with real-time data. (e.g., demand, volts, VArs, reactive reserve, equipment status, transmission line flows, etc.)

5.2. Process/procedures and tools in place for obtaining generation and transmission system information.

5.3. Process/procedures and tools in place to provide transmission system information, in real-time, to the appropriate authorities.

5.4. Process/procedures and tools in place for providing local network integrity by:

5.4.1. Performing reliability analyses, both real-time and contingency analyses.

5.4.2. Establishing thermal, voltage, and stability limits for real-time operations.

5.4.3. Operating the transmission system within the established thermal, voltage, and stability limits.

5.4.4. Implementing adjustments to dc ties.

5.4.5. Setting and coordinating transmission outage schedules

5.5. Process/procedures in place for coordinating with other transmission operators and their reliability authority.

5.6. Process/procedure in place for providing construction and maintenance plans to the Reliability Authority.

5.7. Process/procedure and tools in place for compliance with all applicable NERC reliability standards.

6. **Emergency Operations**

6.1. Process/procedure in place that defines the coordination and implementation of

emergency operations within its local area.

6.2. Process/procedure in place that defines the coordination and implementation of system restoration operations within its local area.

6.3. Plan in place that ensures continued operation during abnormal and emergency conditions due to the loss of facilities.

Reliability Functions

The Standard will Apply to the Following Functions (Check all that apply)		
☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☒	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability and Market Interface Principles (check all that apply)	
1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.	☒
2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand	☐
3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably	☒
4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented	☒
5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems	☒
6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions	☒
7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis	☒
The proposed Standard must comply with all of the following Market Interface Principles	☒
Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
An Organization Standard shall not give any market participant an unfair competitive advantage	
An Organization Standard shall neither mandate nor prohibit any specific market structure	
An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

Related Standards, Function Certification Requirements or Business Practices

Standard No.	***Explanation***

Related SARs

SAR ID	***Explanation***

Regional Differences

Region	*Explanation*
ECAR	
ERCOT	
FRCC	FRCC requires their own confidentiality agreement in addition to the NERC agreement. In addition, FRCC's Security Process (Reliability Plan) has other requirements for tools, etc. that must be met. Also, NERC can not set a requirement for the IA will preempt any state jurisdictional requirements. Linda Campbell for FRCC OC
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WSCC	WECC has additional data and Reliability Management System confidentiality agreements that may or may not be included Ed Riley CAISO

SAR DT Members

Gerry Burrows, Chairman
Pat Everly, Secretary
Larry Alderink
Don Badley
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David Little
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Standard Authorization Request Form

Title of Proposed Standard	Cyber Security
Request Date	May 2, 2003; Revised November 24, 2003

SAR Requestor Information

Name	Charles Noble (on behalf of CIPAG)	**SAR Type** (Check box for one of these selections.)	
Company		☒	New Standard
Telephone		☐	Revision to Existing Standard
Fax		☐	Withdrawal of Existing Standard [1]
E-mail		☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences.)

To protect the critical cyber assets (computers, software, and communications networks) essential to the reliability of the bulk electric system.

Brief Description

This standard is based on the Urgent Action Cyber Security Standard that was adopted by the NERC Board of Trustees on August 13, 2003. The standard requires that critical cyber assets related to the reliable operation of the bulk electric systems are identified and protected. Requirements will be included in the standard for responsible entities to create and implement programs and procedures, perform on-going assessments, and implement appropriate and technically feasible improvements necessary to meet the requirements of this standard. Security programs include the responsible entity's policies, standards, procedures, training, and auditing controls for the implementation of this standard. The standard is intended to replace the Urgent Action Cyber Security Standard.

Reliability Functions

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

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained, and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☒	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. A Reliability Standard shall not give any market participant an unfair competitive advantage. Yes
3. A Reliability Standard shall neither mandate nor prohibit any specific market structure. Yes
4. A Reliability Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. A Reliability Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description

This standard identifies the minimum requirements to implement and maintain a cyber security program to protect cyber assets critical to reliable bulk electric system operation. This standard applies to Reliability Authorities, Balancing Authorities, Interchange Authorities, Transmission Service Providers, Transmission Owners, Transmission Operators, Generator Owners, Generator Operators, and Load Serving Entities, as described in NERC's Functional Model.

Reliable bulk electric system operations are highly interdependent, and the failure of key/critical elements of the generation, transmission, or grid management system can potentially compromise the reliable operation of major portions of the regional grid. Similarly, the wholesale electric market, as a network of economic transactions and interdependencies, relies on the continuing reliable operation of not only physical grid resources, but also the operational infrastructure of monitoring, dispatch, and market software and systems. Because of this mutual vulnerability and interdependence, it is necessary to safeguard the critical cyber assets that support bulk electric system operations by establishing standards to provide a level of assurance that even a single compromise of a critical cyber asset does not compromise system security, and, thus, risk grid or market failure.

This standard shall primarily focus on electronic systems including: hardware, software, data, related communications networks, and control systems as they impact bulk electric system operations and personnel. In addition, physical security shall be addressed to the extent that it is necessary to assure a secure physical environment for critical cyber assets and their operation. If a network consisting of critical cyber assets also includes non-critical cyber assets, those non-critical cyber assets must comply with the requirements of this standard. This standard shall require that third-party providers of services used to ensure reliability (e.g. Interchange Distribution Calculator data) must comply with the standard for systems providing those services. This standard shall require that the responsible entities that must comply with this standard identify and protect themselves from threats from interconnected cyber systems.

This standard shall require that entities identify and protect critical cyber assets related to the reliable operation of the bulk electric system and have an ongoing program in place to ensure their protection. This program must at a minimum, meet the requirements set forth in the standard as they relate to governance, planning, prevention, operations, incident response, and continuity of operations. As a result, this program will mitigate the effect of acts of malicious or unknown origin that could cause wide-ranging, harmful impact to the bulk electric system.

This standard is intended to ensure that appropriate mitigating plans and actions are in place, recognizing the differing roles of each responsible entity and the differing risks being managed. This standard shall use as its starting point the Urgent Action Cyber Security Standard adopted by the NERC Board of Trustees on August 13, 2003. Building on that baseline, this permanent standard shall reflect input received during the balloting of the Urgent Action Standard and comments received in response to this SAR that are aimed specifically at the Urgent Action Standard.

Reliable and secure data communications networks are key to continuity of operational control and ongoing management of critical cyber assets. Some organizations own and operate their own data communications infrastructure, others acquire network services from the Telecommunications Sector, and some meld both private and public resources to create the data communications capabilities necessary to reliably operate and control critical cyber assets. Whether the means of data communications are of private or public origin, be they physical or logical in operation, it is incumbent upon owners and/or operators of critical cyber assets to design and provision data communications capabilities to be reliably available. Accordingly, data communication systems joining two or more distinct electronic security perimeters must be provisioned to a level of reliability at least equal to 99.5% availability per annum. Where the data communications capability utilizes shared public network resources (e.g., POTS, frame relay, the Internet, etc.), using either leased-permanent or temporary dial-up methods, all data must be

encrypted to ensure authorized use of the data communications capability through authentication, confidentiality, integrity, and (as appropriate) non-repudiation.

Definitions

Cyber Assets: Those systems (including hardware, software, and data) and communication networks (including hardware, software, and data) associated with bulk electric system operation. This definition applies only to systems or devices that use a network protocol stack for communications.

Critical Cyber Assets: Cyber assets whose loss or compromise could adversely impact the reliability of bulk electric system operations. Cyber assets that perform bulk electric system functions such as telemetry, monitoring and control, automatic generator control load shedding, black start, real time power system modeling, special protection systems, power plant control, substation automation control, and real time inter-utility data exchange are included at a minimum.

Electronic Security Perimeter: The logical border surrounding the network or group of sub-networks (the "secure network") to which the critical cyber assets are connected, and for which access is controlled.

Physical Security Perimeter: The physical border surrounding computer rooms, telecommunications rooms, operations centers, and other clearly defined locations in which critical cyber assets are housed and for which access is controlled.

Responsible Entity: The organization performing the reliability function to which the standard applies.

Security Incident: Any physical or cyber event of malicious or unknown origin that disrupts the functional operation of a critical cyber asset or compromises the electronic or physical security perimeters.

Related Standards

SAR ID	Explanation
Urgent Action Cyber Security Standard	This standard is based on the Urgent Action Cyber Security Standard (1200) approved by the NERC Board of Trustees on August 13, 2003.

Regional Differences

Region	Explanation
None	

Related NERC Planning Standards/Operating Policies

Standard No.	Explanation
None	

Implementation Plan

Description: *(Provide plans for the implementation of the proposed standard, including any known systems or training requirements.)*

While a formal implementation plan will be developed and published when the standard is drafted, the SAR drafting team suggests consideration of a plan that permits requiring compliance by entities as they certify (where appropriate) to the functional model. The implementation plan must account for the current state of technology and reasonable timeframes to update existing systems.

Industry Representatives who participated in developing this SAR	Chuck Noble — ISO New England Michael Allgeier — Lower Colorado River Authority David Ambrose — Western Area Power Administration Larry Bugh — ECAR Regional Council Greg J. Fraser — Manitoba Hydro Roger L. Lampila — New York Independent System Operator John S.F. Lim — Consolidated Edison Co. of New York, Inc. John G. Maguire — PJM Interconnection, LLC Paul McClay — Tampa Electric Company Kurt Muehlbauer — Exelon Corporation David L. Norton — Entergy Transmission James Sample — California ISO Phil Sobol — Aquila, Inc. Howard Tarler — New York State Dept. of Public Service John D. Varnell — Tenaska Power Services Co. William R. Wagner — Calpine Corporation Bob Wallace — Ontario Power Generation

Note — This form is to be used to comment on version 2 of the Cyber Security Standard Authorization Request (SAR).

E-mail this form between December 1, 2003–January 21, 2004, to: sarcomm@nerc.com with "Standard Comments" in the subject line.

Please review the SAR and answer the questions in the yellow boxes.

If you have questions, please call Tim Gallagher at 609-452-8060 or send a question to timg@nerc.com.

SAR Commenter Information (For Individual Commenters)	
Name	Seiki Harada
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Key to Industry Segments:

1 – Trans. Owners
2 – RTOs, ISOs, RRCs
3 – LSEs
4 – TDUs
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

SAR Commenter Information (For Groups Submitting Group Comments)		
Name of Group:	**Group Representative:** **Representative Phone:** **Representative Email:**	
List of Group Participants that Support These Comments:		
Name	**Company**	**Industry Segment #**

Background Information:

Notes to Industry Commenters:

This standard authorization request will *set the scope* for a NERC standard dealing with cyber security requirements as they pertain to maintaining the integrity and reliability of the interconnected electric systems of North America. When the SAR has been fully developed, the NERC Standards Authorization Committee (SAC) will be contacted for permission to begin drafting the standard.

When completed, the standard will be presented to the NERC registered ballot body for approval. If approved, the standard would replace the urgent action cyber security standard approved by the industry in June 2003.

In developing version 2 of this SAR, the drafting team reviewed and considered all comments submitted during the development of the urgent action cyber security standard and those submitted in response to version 1 of this SAR.

Notable changes made to the SAR in response to industry comments include:

- Revised definitions to added greater clarity
- A reference to the relationship between this SAR and the urgent action standard
- Clarification
- A re-stated purpose
- Addition of new functions to correlate to the recently approved version 2 of NERC's Functional Model
- Removal of 'justification' items that were used in the urgent action SAR
- Clarification regarding third-party vendor requirements
- Clarification regarding requirements for communication links between secure perimeters
- Increased applicability of the standard (both in terms of entities and assets)

1. Do you agree with the definitions included in the SAR?

☐ Yes

x☐ No

According to the present version of the Cyber Asset Definition, a SCADA system may be exempted from the application of the standards if it happens to use a very old networking that is not on a stacked protocol. I would say all SCADA for bulk power system must be included.

Additionally, the detailed description section essentially lists two major purposes for the standards: bulk system reliability and efficient market. Looking at the definitions for Cyber Assets and Critical Cyber Assets, they are defined only for bulk system reliability. If we are truly serving the two purposes, we must include such systems as eTAG, OASIS and other market oriented systems.

The definition of Critical Cyber Assets includes 'black start'. I am not sure if this is pointing to the process to restart the part of the grid that collapsed, or the systems required to start up a generating station that tripped off. Perhaps, we need to qualify the words 'black start'.

2. The SAR requires that data communications between secure perimeters be engineered to a statistical probability of 99.5% uptime on an annual basis (or, 43.8 hours downtime, per year). Do you agree with this as a reasonable design goal?

☐ Yes

x☐ No

Comments:

44 hours per year is a lot of time to be down for 7x24 critical links. I would say we should shoot for about half of that. Further, the cumulative down time alone is not a good measure. It should be combined with the frequency of the communications link going down. For example, even if the communications link is down for only 10 hours per year, if the link was down five times every day for 10 seconds each randomly, the link would be useless.

3. The SAR does not address the availability of critical cyber assets. Should requirements be included? If so, how would availability be measured, especially for

partial failures? What level of availability should be required?

☐ Yes

x☐ No

Comments:

A good level of availability is a function of 1) implementing adequate security measures, 2) maintaining/patching software, hardware and data, 3) operating the systems safely and properly, and 4) external forces which try to disrupt orderly operation. Similar to the number of cyber incidents an entity may encounter in a year, most external factors are not under the control of the entity in question. For example, if there is an overwhelming attack on the DNS server in one sector of the Internet, all Internet based systems and networks might feel the impact (and thus the degraded availability). It is not reasonable to set a standard over a measure for which the entity does not have total control over.

4. The SAR does not require that SCADA or PCS communications be encrypted. Should this requirement be added for:

a. Use of Inter-Control Center Communications Protocol (ICCP), primarily between control centers

x☐ Yes

☐ No

Comments

b. SCADA master station to RTU communications using peer-to-peer communications protocols

x☐ Yes

☐ No

Comments

c. SCADA master station to RTU communications over an established communications stack (e.g. TCP/IP)

x☐ Yes

☐ No

Comments

d. Data collection servers communications to substation IEDs

x☐ Yes

☐ No

Comments

e. If the above were included, how long would each take to complete?

Comments:

This will take a long time to implement (> 10 years?) and a lot of money. We may consider implementing these new measures only to the new implementations and major upgrades as of a certain future date.

5. The SAR does not require redundancy of critical cyber assets, but rather their protection. Should redundancy also be required?

☐ Yes

x☐ No

Comments:

It makes sense to provide redundancy for key SCADA /EMS systems. However, I am not sure if we should be designing in redundancies in ALL the cyber assets declared as 'critical'. It may not be economically feasible to prodive redundancy for all components of all critical systems. Also, we may find that some 'critical' systems are 'more critical' than others….

6. Please enter any other comments you have regarding this SAR in the space below.

Comments

This set of standards is much more wide-encompassing than the Urgent SAR standards. We will need to give sufficient lead time for all participants to implement the additional requirements.

Comment Form — 2nd Posting of the 'Cyber Security' Standard Authorization Request

Note — This form is to be used to comment on version 2 of the Cyber Security Standard Authorization Request (SAR).

E-mail this form between December 1, 2003–January 21, 2004, to: sarcomm@nerc.com with "Standard Comments" in the subject line.

Please review the SAR and answer the questions in the yellow boxes.

If you have questions, please call Tim Gallagher at 609-452-8060 or send a question to timg@nerc.com.

SAR Commenter Information (For Individual Commenters)	
Name	Joe Weiss
Organization	KEMA
Industry Segment #	8
Telephone	(408) 253-7934
E-mail	jweiss@kemaconsulting.com

Key to Industry Segments:

1 – Trans. Owners
2 – RTOs, ISOs, RRCs
3 – LSEs
4 – TDUs
5 - Generators
6 - Brokers, Aggregators, and Marketers
7 - Large Electricity End Users
8 - Small Electricity Users
9 - Federal, State, and Provincial Regulatory or other Govt. Entities

SAR Commenter Information (For Groups Submitting Group Comments)		
Name of Group:	**Group Representative:** **Representative Phone:** **Representative Email:**	
List of Group Participants that Support These Comments:		
Name	**Company**	**Industry Segment #**

Background Information:

Notes to Industry Commenters:

This standard authorization request will *set the scope* for a NERC standard dealing with cyber security requirements as they pertain to maintaining the integrity and reliability of the interconnected electric systems of North America. When the SAR has been fully developed, the NERC Standards Authorization Committee (SAC) will be contacted for permission to begin drafting the standard.

When completed, the standard will be presented to the NERC registered ballot body for approval. If approved, the standard would replace the urgent action cyber security standard approved by the industry in June 2003.

In developing version 2 of this SAR, the drafting team reviewed and considered all comments submitted during the development of the urgent action cyber security standard and those submitted in response to version 1 of this SAR.

Notable changes made to the SAR in response to industry comments include:

- Revised definitions to added greater clarity
- A reference to the relationship between this SAR and the urgent action standard
- Clarification
- A re-stated purpose
- Addition of new functions to correlate to the recently approved version 2 of NERC's Functional Model
- Removal of 'justification' items that were used in the urgent action SAR
- Clarification regarding third-party vendor requirements
- Clarification regarding requirements for communication links between secure perimeters
- Increased applicability of the standard (both in terms of entities and assets)

1. Do you agree with the definitions included in the SAR?

☐ Yes

X No

Comments:

The Cyber Assets definition states: "This definition applies only to systems or devices that use a network stack protocol for communications." This statement needs to be deleted. Cyber assets are not dependent on specific communication protocols. Cyber assets associated with bulk electric system operation utilize non-network stack (non-TCP/IP) protocols such as Modbus, Profibus, and conventional serial RTU communications. Additionally, dial-up modems and unsecured radio links are obviously cyber vulnerabilities and do not use network stack protocols.

The Security Incident definition states: "…any physical or cyber event of malicious or unknown origin…" This is not inclusive enough. There can be cyber events of known, benign origins that can disrupt functional operation of critical cyber assets and cause security incidents. There have been several confirmed cases of benign origin causing denial of service in the utility and other process industries.

2. The SAR requires that data communications between secure perimeters be engineered to a statistical probability of 99.5% uptime on an annual basis (or, 43.8 hours downtime, per year). Do you agree with this as a reasonable design goal?

☐ Yes

X No

Comments:

The critical need for communications is during an upset event such as August 14th. The requirement should be that communications have a 99.5% availability including during upset events.

3. The SAR does not address the availability of critical cyber assets. Should

requirements be included? If so, how would availability be measured, especially for partial failures? What level of availability should be required?

☐ Yes

X No

Comments:

SCADA specifications often require 99.95% availability for critical functions. It is critical that the function be maintained, not necessarily the asset.

4. The SAR does not require that SCADA or PCS communications be encrypted. Should this requirement be added for:

a. Use of Inter-Control Center Communications Protocol (ICCP), primarily between control centers

☐ Yes

X No

Comments:

Encryption does not guarantee the critical functions of authentication and message integrity. Encryption may not be practical for certain generation of SCADA systems. It may not be possible to implement encryption for current plant controls and substation equipment.

b. SCADA master station to RTU communications using peer-to-peer communications protocols

☐ Yes

X No

Comments: Same

c. SCADA master station to RTU communications over an established communications stack (e.g. TCP/IP)

☐ Yes

X No

Comments: Same

d. Data collection servers communications to substation IEDs

☐ Yes

X No

Comments: Same

e. If the above were included, how long would each take to complete?

Comments: See comment 4a

5. The SAR does not require redundancy of critical cyber assets, but rather their protection. Should redundancy also be required?

☐ Yes

X No

Comments:

Redundancy does not necessarily mitigate cyber vulnerabilities. Two systems on the same compromised network can be equally vulnerable even though there is "traditional" redundancy.

6. Please enter any other comments you have regarding this SAR in the space below.

Comments:

1. Distribution providers should be included since many large transmission substations also include distribution equipment that often communicate with transmission devices (and vice versa) making them equally cyber vulnerable. Additionally, DOE tasked NERC to address the electric utility industry- this includes distribution.
2. Market operators should be included per the second paragraph of the detailed description and also because they are part of the electric industry.
3. Encryption should not be required until is it confirmed by testing that encryption is the appropriate technology to meet the required functional needs. This has not yet occurred.

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Standard Authorization Request (SAR) Form

Title of Proposed Standard:	Define (Physical) Connection Requirements
Request Date:	March 7, 2002
Authorized for Posting:	March 20, 2002
SAR ID# :	PHYSCAL_CON_REQ_01_01

SAR Requestor Information		**SAR Type** (Put an 'x' in front of one of these selections)	
Name:	Jim Byrd	X	New Standard
Primary Contact:	Jim Byrd		Revision to existing Standard
Telephone: Fax:	214-743-6870 972-263-6710		Withdrawal of existing Standard
e-mail:	jbyrd@txu.com		Emergency Action

Purpose/Industry Need (Provide one or two sentences)

To establish a standard for the proper physical connection of generation substations, transmission facilities, and load substations to the transmission systems to maintain reliability.

Brief Description (A few sentences or a paragraph) Provide enough detail so that an independent entity familiar with the industry could draft a Standard based on this description.)

Requirements shall be established for the development and implementation of a plan for the physical connection of generation, transmission, and substation facilities to the transmission systems. Requirements shall be developed to necessitate adherence to applicable standards for maintaining reliability, such as the requirements for determining operating limits and requirements for automatic control and protection systems.

SAR: Define (Physical) Connection Requirements

Reliability Functions

The Standard will Apply to the Following Functions *(Put an 'X' in front of each one that applies)*		
	Reliability Authority	Ensures the reliability of the bulk transmission system within its Security Authority Area. This is the highest reliability authority.
	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
	Interchange Authority	Authorizes valid and balanced Interchange Schedules
	Planning Authority	Plans the bulk electric system
	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
X	Transmission Owner	Owns transmission facilities
	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
X	Distribution Provider	Provides and operates the "wires" between the transmission system and the customer
X	Generator	Owns and operates generation unit(s) or runs a market for generation products that performs the functions of supplying energy and Interconnected Operations Services
	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required.
	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

SAR: Define (Physical) Connection Requirements

Reliability and Market Interface Principles

Applicable Reliability Principles *(Put an 'x in front of all that apply)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions.
	2. The frequency of interconnected bulk electric systems shall be controlled within defined limits through the balancing of electric supply and demand
X	3. Information necessary for planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably
	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems
	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions
X	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis

Does the proposed Standard comply with all of the following Market Interface Principles? *(Enter 'yes' or 'no')*	Yes
1. Interconnected The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy	
2. An Organization Standard shall not give any market participant an unfair competitive advantage	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards	

Define (Physical) Connection Requirements

SAR Commenter Information			
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Organization	Calpine		
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E-mail	dmcmillan@calpine.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	Bill Carr		
Organization	Dynegy, Inc.		
Telephone	713-7657-8723	Fax	713-767-5986
E-mail	bill.carr@dynegy.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The purpose/industry need section should start with: The purpose of this standard is to ensure that a consistent, uniformly applied standard is developed for ...

SAR Commenter Information			
Name	John Anderson and John Hughes		
Organization	Electricity Consumers Resource Council (ELCON)		
Telephone	202-682-1390	Fax	202-289-6370
E-mail	jhughes@elcon.org/janderson@elcon.org		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: The establishment of this SAR is premature. All commercial implications of the SAR should be identified and mitigated prior to the drafting.

SAR Commenter Information			
Name	Phil Park		
Organization	Powerex		
Telephone	604 891 5020	Fax	604 895 7012
E-mail	phil.park@powerex.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: If this SAR is to address physical connection requirements, then the sentence "These connection requirements will include a description of real and reactive power requirements for all elements of the transmission system (including generators)" should be elimininated. It is not clear why real power requirements need to be specified. Load power factors can be specified by TOs and DSPs. See my other comments below.

Other comments: The purposes served by this SAR could theoretically be determined in a commercial venue on a generator by generator basis through negotiations with the connecting utilities. One purpose for having a standard on this would be to provide a standard treatment for all generators. Consequently this SAR is more of a technical specification for a commercial requirement, rather than a core reliability requirement. We would have a specification such as this if required to ensure equal treatment of generators or if the cost of meeting the specification was low enough that it was not worth negotiating one-off requirements for each generator. One option to the reactive power requirements proposed for this SAR could be ancillary services charges/payments for reactive power associated with transfers, which ties this SAR into the tariffs. This SAR appears to have significant commercial issues.

SAR Commenter Information			
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Organization	MAAC		
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E-mail	dicapram@pjm.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments:
Physical Interconnection Agreements are contractual arrangements. These arrangements are directly tied to Transmission Facility owners and NOT to North American standards.

SAR Commenter Information			
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None			

SAR Commenter Information			
Name	Alan Johnson		
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Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: Mirant does not believe that this standard is necessary. It encompasses issues that are covered in other SARs. If it is determined that the standard is necessary however, must keep in mind that today's Interconnection Agreements are contracts which cover issues other than reliability. The standard must not attempt to resolve non-reliability oriented, commercial issues.

April 23, 2002

SRP Comments on NERC 11 SAR sent out on April 2, 2002.

All 11 SAR's (this group of 10 plus the one sent out earlier) don't contain enough information to make the kind of judgments requested on the forms. Therefore the forms are not filled out.

We recommend all the SAR's be advanced to the next step to develop the specific standards and associated measurements for each standard so that we can evaluate and comment on them.

All of these SAR's are needed for reliable planning and operation of the bulk electric transmission system and meet the principle requirements.

Comments on the White paper:

1. The paper fails to state what standards are supposed to be. This seems so basic; one has to assume that those drafting the white paper want to redefine the definition contained in the Organizational Standards Manual. This leads to a lot of confusion and is not the place to do that.

2. The Planning Standards were written in a different time period than the Operating Policies with different objectives. Thus they are different and that should be recognized. For instance the development of a Planning Functional model has absolutely nothing to do with whether control areas exist or not and whether companies have restructured or not. The statement about control areas may be true for the Operating Policies but it is not try for the Planning Standards.

   The Planning Standards (Templates) were written to meet the definition of a standard in the Organizational Standards Manual, to meet at least one of the Reliability Principles, to comply with all the Market Interface Principles and to contain the compliance administration elements. This is very different than what is contained in the Operating Policies. The Planning Standards need to go through the new process so that both the Operating elements and Planning elements of the Organizational Standards are consistent, are not duplicative and are needed for reliability.

3. The term " core reliability requirement" is used in the white paper but is never mentioned in the Organizational Standards Manual. Using an undefined term is very misleading and should be avoided.

4. The paper in several places address "what performance must be achieved". As noted above, an Organizational Standard can be broader than that and this write up is misleading.

5. The process has been lengthened because of the multiple posting of the SAR's. NERC has a body of reliability requirements written up into Compliance Templates. With very little effort these could be written up into SAR's that would provide sufficient detail for NERC to evaluate them. It is very hard to comprehend why one does not use this work to expedite the process. Instead SAR's are sent out with insufficient information. The process is long enough. We should be looking for all ways possible to speed it up.

Comments on the SAR write-up:

1. The SAR write-up only contains the purpose and brief description of a standard. Where is the Standard? I thought that is what the SAR is for?

2. The descriptions are in most cases extremely vague. The write-ups contain words like "such as" or "as defined in the standard". These are big enough to cover a MAC truck. Once again there is insufficient information to make a good judgment.

April 29, 2002

Guy V. Zito
Manager, Planning
Northeast Power Coordinating Council
1515 Broadway Floor 43
New York, NY 10036

RE: NEPOOL Compliance Working Group (NCWG) comments pertaining to the 10 Standard Authorization Requests (SARs) posted for open comment

The NCWG has reviewed the 10 SARs posted for open comment and has agreed they are core standards, which serve a purpose in support of reliability.

Standard Title:
Prepare for and Respond to Abnormal or Emergency Conditions
Prepare for and Respond to Blackout or Island Conditions
Coordinate Interchange
Coordinate Operations
Monitor and Analyze Disturbances, Events and Conditions
Operate Within Limits – Monitor and Assess Short-term Transmission
Define (Physical) Connection Requirements
Design, Install, and Coordinate Control Protection Systems
Assess Transmission Future Needs and Develop Transmission Plans
Determine Facility Ratings, Operating Limits, and Transfer Capabilities

We do not agree that the **SAR Type** is a new standard. We suggest that at a minimum the SAR should indicate the existing standard and whether or not it will be withdrawn when the revised standard is adopted. We suggest that NERC stop the open process of reviewing existing policies and standards if these Organizational Standards will replace them. NERC should clearly indicate that one purpose of the Organizational Standards Process is to replace existing standards.

Sincerely,
Daniel L. Stosick

Chairman, NEPOOL Compliance Working Group
C/o ISO New England, Inc.
One Sullivan Road
Holyoke MA 01040-2841

Cc: NEPOOL Compliance Working Group
CP9 Working Group
Paul Shortly
Richard Burke
Richard Kowalski

SAR Commenter Information			
Name	Robert D. Smith		
Organization	Arizona Public Service		
Telephone	(602) 250-1144	Fax	(602) 250-1155
E-mail	robert.smith@aps.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	Mr. Charles Moser (Northborough, MA) and Mr. Ronald Halsey (Syracuse, NY)		
Organization	National Grid USA		
Telephone	508 421 7600 315 428 3181	Fax	508 421 7520 315 428 5615
E-mail	charles.moser@us.ngrid.com ronald.halsey@us.ngrid.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: Again, the standard as written is much too detailed to be useful to all Regions. All that is required is that the Regions have in place Connection Requirements that will allow the Region to meet the transmission system performance based reliability requirements defined in the first standard.

SAR Commenter Information			
Name	Vern Colbert		
Organization	Dominion Virginia Power		
Telephone	(804) 273-3399	Fax	(804) 273-2405
E-mail	vern_colbert@dom.com		
Other comments: Comments to be provided by others			

SAR Commenter Information			
Name	Greg Gideon		
Organization	TXU Energy		
Telephone	214-875-9483	Fax	214-875-9246
e-mail	ggideon1@txu.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?
☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	Paul Rocha		
Organization	Reliant Energy HL&P		
Telephone	713-207-2768	Fax	713-207-2281
e-mail	paul-rocha@reliantenergy.com		

Interconnection schemes should be designed to meet the applicable planning standard for the transmission system. HL&P sees no value in developing a separate, stand-alone interconnection standard. If a standard is developed, the same tradeoff between reliability, costs, and landowner impact exists as discussed in our comments concerning transmission planning standards. Therefore, like the transmission planning standard, we believe that if NERC chooses to develop a standard, it should not apply to the intrastate ERCOT region.

Furthermore, it is worth noting that, like the issue of generator control standards, there are commercial and public policy considerations in the design of interconnection schemes. It has long been the case that, whether connected at the distribution level or transmission level, some customers will desire more reliability than others. Typically, the rules for how this issue is addressed are found in individual utility service extension tariffs reviewed and approved by regulatory authorities. Most tariffs contain the concept of providing a standard service extension, with cost responsibility for non-standard service borne by the requesting customer, so that other customers are not harmed by the additional requirements of such customers.[2] These issues are best addressed by regulatory authorities, not by NERC.

[2] A non-standard service request could be for additional reliability or for other reasons, such as aesthetics (underground service extension lines, for example).

SAR Commenter Information			
Name	Brant Eldridge		
Organization	ECAR		
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E-mail	brante@ecar.org		

ECAR has conducted a survey of its member companies regarding the eleven SARs, which NERC has initiated to-date. We recognize that the comment period for the first SAR issued ("Balance Resources and Demand") has already closed. However, considering that the first SAR was issued earlier than the other ten primarily just to get the process started, and further considering that all 11 SARs are viewed by NERC as a possible complete set of Organization Standards (re: the "White Paper"), ECAR believes that comments on the first SAR should still be considered along with those on the other ten.

11 of the 18 ECAR Full Members, along with two Associate Members, submitted responses to the SAR survey. Some of the responses were submitted using the NERC "SAR Comment Form", while others were contained in narrative e-mails, and one was faxed to us. Therefore, a complete set of the ECAR member company responses will be sent to the Standards Process Manager at NERC via Fed Ex to arrive at NERC by May 3rd. The Fed Ex package will include a copy of this e-mail. FYI, NERC may also receive some of the ECAR member company responses directly from the companies. Some of the individual company responses will be identical to what will be in the Fed Ex package and some will contain more detailed comments.

The ECAR member company responses contain numerous and wide-ranging comments about the need for each of the 11 proposed Organization Standards, as well as comments regarding the scope and applicability of the SARs. As your review of these responses will show, there is general ECAR consensus – but not unanimity -- that the 11 SARs as a set cover the scope of performance needed to ensure reliability of the interconnected North American bulk power systems. Some ECAR members feel that there are performance areas not covered in the proposed set of Organization Standards, and they have provided what they think is missing. Others believe that some of the proposed Organization Standards are not needed, and they explain why they feel that way. Numerous comments were directed at the scope and applicability of the SARs. Several ECAR companies questioned the inclusion of the "Distribution Provider" function in the applicability section of the SARs, believing that NERC should stick to its traditional focus on the bulk power systems and stay out of the distribution arena.

The recent call for nominees to serve on SAR Drafting Teams is the appropriate next step. ECAR believes that all 11 SARs need to be refined to reflect industry comments and then posted again for another round of industry comments. Before proceeding into actual development of Organization Standards based on these 11 SARs, NERC must have clear industry consensus on the need for each of the Organization Standards outlined in the 11 SARs, as well as consensus on the scope and applicability of those SARs.

If the wide-ranging comments received from ECAR members are any indication, there is still some serious work to be done to achieve the needed clear industry consensus on how to proceed.

SAR Commenter Information			
Name	David L. Hart		
Organization	Ohio Valley Electric Corporation		
Telephone	614/223-1090	Fax	614/223-1094
E-mail	dlhart3@aep.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: Once again are the transmission owners the ones that should be responsible? What about operators or providers?

SAR Commenter Information			
Name	Lew Gray, Mike Holtsclaw, Steve Clouse		
Organization	Indianapolis Power & Light		
Telephone	317-261-8126	Fax	317-261-8996
E-mail	lew.gray@aes.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?
☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	David W. Sandefur		
Organization	Hoosier Energy REC, Inc.		
Telephone	812-876-0267	Fax	812-876-3139
E-mail	dsandefur@hepn.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

Other comments: The Distribution Provider functional area should be removed from this Standard since NERC standards should continue to focus on regional or larger scale reliability issues. To reach down to the distribution level will broaden the scope significantly and unneccesarily.

SAR Commenter Information			
Name	Verne B. Ingersoll, II		
Organization	Progress Energy - Carolina Power & Light Company and Florida Power Corp.		
Telephone	919-546-7534	Fax	919-546-7558
E-mail	verne.ingersoll@pgnmail.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?
☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☒ The scope of the SAR should be expanded to include:
Coordination with all entities responsible for protective relaying. Coordination is a key component of this standard and is not addressed in the scope. The reliability functions should include coordination among all entities that design, install, operate, maintain and test controls and protective relays. For example, LSEs are the primary entities responsible for load shedding and are not included in the list.
☒ The scope of the SAR should be reduced to eliminate:
It appears from the "Description" that this could include AGC. The AGC should be separate from the transmission system protection and controls.
Other comments: It isn't clear what automatic control refers to. For instance, is capacitor control included, generation control, etc.

It seems like a broad topic to cover such a short description.

There should be a differentiation between AGC and transmission protection system and control areas. The two are not really related at the design level. AGC is covered by number 5 in the initial listing.

The SDT will need to take care to include all previously approved Standards related to protection and control.

Design standards are presently covered by IEEE and other organizations. NERC standards should not overlap with these technical standards.

The title does not include maintenance and the purpose does. The description includes both.

What are the reliability standards that are mentioned in the description? Does this refer to Table I in the current I.A. standard?

SAR Commenter Information		
Name	Charles Yeung	
Organization	Reliant Resources	
Telephone	713-207-2935	Fax
E-mail	cyeung@reliant.com	

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: A plan is not a standard. This SAR does not propose any measurable or quantifiable boundary conditions for achieving reliability. It only proposes that a plan be assembled that describes the physical interconnection requirements necessary to achieve reliability requirements established through other standards.

Other comments: Though such an interconnection plan may be beneficial to ensure interconnection of equipment to the grid is done in a reliable manner, such a requirement will not contain meaningful and measurable conditions. The core reliability that this SAR proposes to achieve is already contained in SARs such as: Determine Facility Ratings, Operating Limits and Transfer Capabilities; Design, Install, and Coordinate Control and Protection Systems; Prepare for and Respond to Abnormal Emergency Conditions, Prepare for and Respond to Blackout or Island Conditions; Monitor and Analyze Disturbances, Events and Conditions; Balance Resources and Demand. This standard as proposed will be difficult to measure and enforce. There are numerous procedures and requirements that may be required to facilitate the reliability needs, however, not all of them fall under the definition of a core Organization Standard that is measurable. NERC must distinguish these requirements from core Organization Standards and apply an appropriate standards development process for them.

SAR Commenter Information			
Name	Kirit S. Shah		
Organization	Ameren Services -Energy Delivery Technical Services		
Telephone	314 554 3542	Fax	314 554 3260
E-mail	kirit_s_shah@ameren.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The scope is too general.

SAR Commenter Information			
Name	Dan Wheeler		
Organization	NorthWestern Energy		
Telephone	(406) 497-2234	Fax	(406) 497-3002
E-mail	dan.wheeler@northwestern.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	John K. Loftis, Jr.		
Organization	Dominion Virginia Power		
Telephone	804 - 273 - 3897	Fax	804 - 273 - 3259
E-mail	john_loftis@dom.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: (1) - This SAR also applies to the Planning Authority function. (2) - Consideration should be given to developing a "pro-forma" format for use in developing connection requirements documents. This "pro-forma" would provide guidelines on what required elements should be included, and would promote more consistency. Currently, some entities' facilities connection requirements consist of a 1 page document, while others have developed a 200 page document. (3) - Future development of this SAR should also take into consideration the direction of FERC regarding a "pro-forma"/standardized set of generation interconnection procedures.

SAR Commenter Information			
Name	Terri Grabiak		
Organization	Allegheny Power		
Telephone	724-838-6748	Fax	724-838-6156
E-mail	tgrabia@alleghenypower.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?
☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information		
Name	George Bartlett	
Organization	Entergy Services	
Telephone	504-310-5801	Fax
E-mail	gbartle@entergy.com	

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: Any requirements for the interconnection of generation, transmission or substation equipment should be established by the facility owner and the transmission owner. NERC should not be establishing equipment design, performance, coordination, installation, nor maintenance requirements. This is not a "core reliability" Organization Standard and should be eliminated.

SAR Commenter Information			
Name	Michael Desselle		
Organization	American Electric Power		
Telephone	214-777-1826	Fax	214-777-1831
E-mail	mddesselle@aep.com		
Other comments: To the extent that this SAR is transitioning an existing standard from the old world to the new world (Functional Model), then the standard should not go beyond the original scope. Consistent with our general comments, once the clarity is achieved on Standard Market Design and RTO formations, then this standard should be revisited and reevaluated.			

SAR Commenter Information			
Name	Ed Kirschner		
Organization	Cinergy		
Telephone	317-838-1455	Fax	317-838-6846
E-mail	ekirschner@cinergy.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: Requirements for determining operating limits is already specified in another SAR - what is meant by this?

Other comments: If this refers to the development of the connection document by the Transmission Owner then why are Distribution Providers and Generators indicated as functions that this standard will apply?

SAR Commenter Information			
Name	Jim Griffith		
Organization	Bulk Power Operations Southern Company		
Telephone	205-257-6892	Fax	205-257-6663
E-mail	jsgriffi@southernco.com		
None			

SAR Commenter Information			
Name	Peter Burke (submitting comments provided by numerous ATC contributors)		
Organization	American Transmission Company		
Telephone	262-506-6863	Fax	262-506-6709
E-mail	PBurke@atcllc.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☒ The scope of the SAR should be expanded to include: Guidelines for including connection requests in regional models.
☒ The scope of the SAR should be reduced to eliminate: Any reference to connection of distribution provider connections unless in the judgment of the transmission provider it affects the reliability of the interconnected system. The bulk power system may need to be defined as those stations in the normal course or under single contingency. Also should only address new sites or where major revisions occur and can be feasibly upgraded.
Other comments: (1) This standard should state the minimum requirements and should not prevent the transmission owner from establishing additional requirements if necessary.

It seems that the Reliability Authority should play a role considering it is responsible for the reliability of the bulk transmission system. They should ensure that an entity connecting to the bulk transmission system conforms to their requirements.

(2) May also need to address the issue of local regulatory input on reliability and access standards for distribution or customer choice.

(3) It would seem that to facilitate the ability to provide a reliable transmisison system there is also a need to develop some guides for modeling requested connections in system models. The eastern interconnection can't do a reasonable reliability study right now because most parties responsible for planning the system have no idea which connections should be modeled in their own system let alone in surrounding systems.

(4) The "transmission operator" reliability function should also apply since they are the people that will need to operate that physical connection.

SAR Commenter Information			
Name	Bob Pierce		
Organization	Duke Power		
Telephone	(704) 373-6480	Fax	(704) 382-7887
E-mail	rwpierce@duke-energy.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The SAR should also apply to the following organizations: Planning Authority, Transmission Operator, and Load-Serving Entity.

SAR Commenter Information			
Name	David Little		
Organization	Nova Scotia Power Inc.		
Telephone	902 428-7580	Fax	902 428-7550
E-mail	david.little@nspower.ca		

Is there a reliability-related need for an Organization Standard to be developed on this topic?
Yes
Is the Scope of the SAR fine as it is?
No
Other Comments
Based on the Purpose / Description, as stated in the SAR, the purpose of the standard which is to follow is not clear.

A standard based on this description appears to be getting into the "how" to design / build area. The White Paper on NERC's Organization Standards suggests that the standards will be focused on defining "what" performance levels are required.

SAR Commenter Information			
Name	Art Giardino		
Organization	Public Service Electric & Gas		
Telephone	973 430-6374	Fax	973 242-6074
E-mail	arthur.giardino@pseg.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: It is premature to continue development of this SAR until FERC has specified the organization to be responsible for the development of wholesale electric standards.

SAR Commenter Information		
Name	Compliance Subcommittee	
Organization	SERC (Contact = Nancy Fallon)	
Telephone	704-892-6026	Fax
E-mail	nfallon@serc1.org	
None		

SAR Commenter Information		
Name	OPWG	
Organization	SERC (Contact = Nancy Fallon)	
Telephone	704-892-6026	Fax
E-mail	nfallon@serc1.org	
None		

SAR Commenter Information		
Name	Planning Standards Working Group (PSWG)	
Organization SERC (Contact = Nancy Fallon)		
Telephone	704-892-6026	Fax
E-mail	nfallon@serc1.org	

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	Gary Won and Don Tench Comments submitted on behalf of the Independent Electricity Market Operator (IMO)		
Organization	Independent Electricity Market Operator (IMO)		
Telephone	905-855-6427	Fax	905-855-6372
E-mail	gary.won@theimo.com and don.tench@theimo.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate:

The SAR must be rigorously tested against the White Paper requirements to specify what performance must be achieved rather than how to achieve it. For example, in what way is a 'plan for the physical connection of generation….' a performance standard?

The scope should be reduced to eliminate the development and implementation of a plan. The need is for a set of criteria applicable to the assessment of proposals for new or modified physical connections to the transmission system, to ensure that system reliability is maintained. These criteria would be applicable to generator, transmission and load facilities.

SAR Commenter Information		
Name	David Scarpignato	
Organization	Baltimore Gas & Electric	
Telephone	410-597-7593	Fax
E-mail	scarp@bge.com	

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The promulgation for comment of these SARs is premature. The industry "standard making process" is in a transition phase and it is overly burdensome to devote resources at this time. Once legislation or FERC firmly determines which entiy(ies) is responsible for standards it will make sense to move forward with said entity.

Even if NERC wants to cover reliability standards, almost all standards have a reliability and commercial impact; thereby, necessitating developing a single process that incorporates both commercial and reliability aspects of standards development. The current NERC process risks being changed soon, discounts commercial aspects, and is not part of a finalized overall industry process.

Waiting a short while to move forward on a new standards setting process is acceptable and prudent given that NERC standards are currently in place and the industry can continue to use these standards until the new process and standards setting organization(s) are firmly set.

SAR Commenter Information		
Name	R. Scott Henry, Chairman	
Organization	Interconnected Operations Services Subcommittee, NERC	
Telephone	(704) 382-6182	Fax
E-mail	rshenry@duke-energy.com	

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is

SAR Commenter Information			
Name	Jim Cyrulewski Manager -Michigan Electric Power Coordination Center		
Organization	Michigan Electric Coordinated Systems (MECS)		
Telephone	734-665-3628	Fax	734-665-3480
E-mail	cyrulewskij@dteenergy.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The Transmission Operator also has a role since the TO will be operating the transmission facilities that are interconnected.

SAR Commenter Information			
Name	Kent Saathoff		
Organization	Kent Saathoff		
Telephone	(512)225-7011	Fax	(512)225-7020
E-mail	ksaathoff@ercot.com		

Comments

This SAR and the other posted SARs provide an appropriate framework for transitioning existing NERC Operating Policies and Planning Standards into new, NERC Organization Standards. Multiple compliance measures may be defined and developed for each of the eleven proposed Organization Standards. The Organization Standards and related compliance measures should focus on what functions must be performed for reliability, on who is responsible for each compliance measure for each required function and not, on how the compliance measure is achieved. The compliance measure must be measurable or demonstrable to ensure compliance.

Detailed physical requirements for connecting generation, transmission and substation facilities to an electric system will differ depending on the facility and system characteristics. A Standard addressing these requirements should only include the basic considerations needed to reliably connect the facility to the system.

This Standard should also include requirements to Design, Install, and Coordinate Control and Protective Systems (SAR ID# PROTECT_SYSTEMS_01_01) related to these facilities.

Requirements for coordinating switching procedures be included in this SAR or in SAR ID# COORD OPERATIONS 01 01.

SAR Commenter Information			
Name	Ronald Gunderson		
Organization	MAPP Reliability Council		
Telephone	(402)845-5252	Fax	(402)845-5205
E-mail	rogunde@nppd.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: The scope of the standard should be specific to system reliability.

Other comments: This Standard should define a requirement for the Transmission Owners to develop a document which defines what the physical connection requirement is. The elements to be included in this document should not be narrowly defined in the Standard but should be flexible in scope to address specific regional requirements which may exist.

SAR Commenter Information			
Name	Linda Clarke		
Organization	Exelon Corporation		
Telephone	(610) 765-6698	Fax	(610) 765-6698
E-mail	lclarke@pwrteam.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The other SARs should ensure that the connection requirements will meet the reliability standards. The plan is ouside the scope of work. The FERC's Notice of Proposed Rulemaking for Generation Interconnections provides a means by which NERC can provide comments on the plan for physical connection.

SAR Commenter Information			
Name	Carter B. Edge		
Organization	Southeastern Power Administration		
Telephone	706-213-3855	Fax	706-213-3884
E-mail	cartere@sepa.doe.gov		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: There needs to be a way to address an existing connection that has been operating reliably in the past. That is, if a proven connection is functioning reliably it should be evaluated rather than mandated to change its connection.

SAR Commenter Information			
Name	Warren Schaefer		
Organization	Dairyland Power Cooperative		
Telephone	608/787-1252	Fax	608/787/1327
E-mail	wjs@dairynet.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: The scope of the standard should be specific to system reliability.

Other comments: This Standard should define a requirement for the Transmission Owners to develop a document, which defines what the physical connection requirement is. The elements to be included in this document should not be narrowly defined in the Standard but should be flexible in scope to address specific regional requirements, which may exist.

SAR Commenter Information			
Name	Mike Miller		
Organization	Southern Company		
Telephone	205 257 7755	Fax	6663
E-mail	mbmiller@southernco.com		
None			

SAR Commenter Information			
Name	Jim Griffith		
Organization	Bulk Power Operations Southern Company		
Telephone	205-257-6892	Fax	205-257-6663
E-mail	jsgriffi@southernco.com		
None			

SAR Commenter Information		
Name	Southern Company	
Organization		
Telephone	(205) *257-4222*	Fax (205) *257-1040*
E-mail	DGPIATT@southernco.com	

Is there a reliability-related need for an Organization Standard to be developed on this topic?
☒ Yes ☐ No
☐ Yes ☒ No The scope of the SAR is fine as it is
☒ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate:

Other comments:

We agree that NERC has a role in establishing a set of minimal requirements that provide direction for system interconnection; however, as written this SAR is entirely too broad and needs to be much more specific in nature. The scope of this standard should not be expanded beyond the current I.C.S1.M1 standard. Due consideration should be given to ensuring that existing plants do not have new requirements imposed upon them that exceed their current interconnection requirements. A grandfather and/or back-fit rule should be included to protect existing facilities, which are already interconnected with the grid. New requirements should only be imposed on existing plants where there is a clear reliability need with supporting technical justification.

SAR Commenter Information			
Name	Jon. Loresch		
Organization	FirstEnergy Solutions		
Telephone	330-315-7313	Fax	330-315-6773
E-mail	LoreschJ@FirstEnergyCorp.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include: responsibility for development of the interconnection plan by an independent entity.

SAR Commenter Information			
Name	Ray Morella		
Organization	FirstEnergy Corp		
Telephone	330.336.9831	Fax	330.336.9024
E-mail	morellar@firstenergycorp.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: There should most definitively be a standard that governs the physical connection of generation substations, transmission facilities, and load substations to the transmission system. With the expanding market of independent generation we clearly need standards that will govern the connection criteria of these entites. Even without the expanding independent generator sector, our industry needs to create viable, equitable, and responsive criteria that addresses generation, transmission, and load connection points. FERC, with its pending ruling on generation standard protocol, has already taken a step in this process. A standard that NERC can develop that will be consistant with the FERC effort would be benificial. No such standard that specifically addresses load and transmission, other than current NERC policy, exists today.

SAR Commenter Information			
Name	Scott Helyer		
Organization	Tenaska		
Telephone	817-462-1512	Fax	817-462-1510
E-mail	shelyer@tnsk.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is

☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: It appears that specifying requirements for operating limits and AGC go beyond the Physical Connection Requirements. We need to ensure that this Standard would not overlap another reliability standard on operating limits and that we do not create a reliability requirement that AGC is needed for all generators when the market should decide which generators require AGC. Writing a standard that indicates how AGC should be provided if a generator wishes to provide such a service would be acceptable.

SAR Commenter Information			
Name	Kenneth A. Githens		
Organization	Allegheny Energy Supply		
Telephone	412-858-1635	Fax	412-856-2912
E-mail	kgithen@alleghenyenergy.com		
The scope of the SAR should be reduced to eliminate: This standard should define items directly related to the point of demarcation only (i.e. one breaker versus back-to-back breakers) and not issues that would have market implications.			

SAR Commenter Information			
Name	Chifong Thomas		
Organization	Pacific Gas and Electric Company		
Telephone	(415) 973-7646	Fax	(415) 973-8804
E-mail	clt7@pge.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: If this SAR also includes requirements for machine characteristics, such as AVR, relay coordination, etc. then Planning Authority and Reliability Authority Functions would need to be added.

SAR Commenter Information			
Name	Vahid Madani		
Organization	WECC Remedial Action Scheme Reliability Task Force		
Telephone	(510) 874-2300	Fax	(510) 874-2442
E-mail	vxm6@pge.com		
None			

SAR Commenter Information			
Name	Ed Riley		
Organization	California ISO		
Telephone	(916) 351-4463	Fax	(916) 608-5906
E-mail	eriley@caiso.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: This SAR appears to be be a duplicate of portions of the preceding SAR - "Determine Facility Ratings, Operating Limits, and Transfer Capabilities" - specifically the sections regarding transmission facilities and load substations. An addition to the preceding SAR may be more appropriate to cover new generator interconnections. Additionally, FERC has a NOPR out on generator interconnections which may codify some of the details of this SAR thus making a standard unnecessary or redundant.

SAR Commenter Information			
Name	Mr Paul Tremblay, Mr. Mike Penstone, and Mr Ajay Garg		
Organization	Hydro One Networks Inc.		
Telephone	416 345-5420	Fax	416 345-5422
E-mail	ajay.garg@HydroOne.com; mike.penstone@HydroOne.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:

☒ The scope of the SAR should be reduced to eliminate: We do not believe that a detailed NERC standard, as written is required. Regions/RTO/ and entites operating Bulk Electric System should establish Connection Requirements to meet defined performance standards for the interconnected Bulk Electric System.

SAR Commenter Information			
Name	Marv Landauer		
Organization	BPA		
Telephone	360-619-6602	Fax	360-619-6945
E-mail	mjlandauer@bpa.gov		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☒ The scope of the SAR should be reduced to eliminate: The last sentence of the description should be modified to add the words "and safety" after "standards for maintaining reliabilty" and delete the words "the requirements for determining operating limits and". This standard should be for physical connections, not operations.

Other comments: This standard must allow for Transmission Owners to supplement the standards with their own requirments.

SAR Commenter Information			
Name	Francis J Halpin		
Organization	Bonneville Power Administration - Power Business Line		
Telephone	503 230 3000	Fax	503 230 5669
E-mail	fjhalpin@BPA		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate: To separate into additional standard(s).

Other comments: This seems too broad. Would like the SAC to consider a separate standard for generator connections, at the least. It seems that measurement criteria would be unmanageable with every possible type of connection addressed under a single standard. There are a broad range of Functional Entities, which would be affected by this standard. (suggest adding RA, PA, TOP, PSE, LSE to the list of functional groups to which this standard would apply) Segmentation into two or more standards would allow for more specific target functional groupings.

SAR Commenter Information		
Name	Edward Stoneburg	
Organization	Illinois Power Company	
Telephone	(217) 362 6363	Fax
E-mail	edward_stoneburg@illinoispower.com	

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☐ Yes ☒ No

☐ Yes ☒ No The scope of the SAR is fine as it is. There is no need for this standard. The defining of physical connection requirements by a Transmission Owner is a commercial issue. In defining those requirements the Transmission Owner would adhere to appropriate reliability standards such as Control and Protection or establishing Operating Limits.

☒ The scope of the SAR should be expanded to include: Planning Authority & Transmission Operator: In reviewing the Planning Authority and Transmission Operator Responsibilities Illinois Power believes that the PA and TO will play a significant roll in defining physical connection requirements and therefore this standard should apply to them as well as the Transmission Owner

☒ The scope of the SAR should be reduced to eliminate: In Reviewing the Distribution Provider and Generator responsibilities in the Functional Model, neither has any responsibility indicated for the activities identified in the SAR. This standard should not be applied to them.

Other comments: The SAR indicates that this standard would apply to Generators and Distribution Providers. Today NERC Policy and Standards do not apply to these Functions. For example, NERC has no authority to require its standards to be applied to determine connection requirements for distribution facilities. And the application of NERC standards to Independent Generators are carried out by transmission owners through interconnection agreements. Is NERC proposing that this will change and they will begin to impose standards directly on distribution providers and generators? In any case neither a SAR nor a Standard should define the plan for physical connection of a generator, rather it should only be defining the reliability standards to be adhered to and achieved.

SAR Commenter Information			
Name	Saif Mogri		
Organization	WECC Technical Studies Subcommittee		
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E-mail	smogri@email.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: If this SAR includes requirements for machine characteristics, such as AVR, relay coordination, etc., then the Planning Authority and Reliability Authority Functions would need to be added.

SAR Commenter Information			
Name	Gerald N. Rheault		
Organization	Manitoba Hydro		
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E-mail	gnrheault@hydro.mb.ca		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:
Other comments: The Industry Need has not been defined for this SAR.

This Standard should define a requirement for the Transmission Owners to develop a document, which defines what his physical connection requirement is. The elements to be included in this document should not be narrowly defined in the Standard but should be flexible in scope to address specific regional requirements, which may exist.

SAR Commenter Information			
Name	Donald D. Taylor, PE		
Organization	Westar Energy		
Telephone	785-575-6430	Fax	785-575-1798
E-mail	don_taylor@wr.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☒ Yes ☐ No The scope of the SAR is fine as it is
☐ The scope of the SAR should be expanded to include:
☐ The scope of the SAR should be reduced to eliminate:

Other comments: The Purpose specifies "load substation", but the Brief Description says simply "substation". The term "substation" by itself is expansive enough to include all of them. The Planning Authority should be included in the Reliability Functions to ensure broad regional uniformity of the connection requirements.

SAR Commenter Information			
Name	Frank A. Venhuizen		
Organization	NIPS (Northern Indiana Public Service Co.)		
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E-mail	favenhuizen@nisource.com		

Is there a reliability-related need for an Organization Standard to be developed on this topic?

☒ Yes ☐ No

☐ Yes ☒ No The scope of the SAR is fine as it is

☒ The scope of the SAR should be expanded to include: Planning Authority in Reliability Functions

TAB 7
WEQ Seams Catalog

NAESB WEQ
Seams Catalog
Responsible Organization Selection Concepts
February 4, 2004

The NAESB WEQ Seams Subcommittee approved the following list of concepts for adoption during a conference call held on January 16, 2004. The WEQ Executive Committee amended them at their meeting on February 3-4, 2004.

These concepts were used to determine what organization is responsible for the development of an industry standard or regional solution to a specific market seams issue. The attached catalog utilizes the identified concepts to determine the information in the "Issue Type" and "Resp Org" columns.

The responsible organization selection concepts are as follows:

1. FERC will not be designated as a 'Responsible Organization' for purposes of the Seams Catalog.
   - It is understood that FERC is the default regulatory policy making organization.
   - FERC acts as a backstop for evaluating and/or requiring industry developed standards.

2. If the 'Region 1' and 'Region 2' fields for a specific issue state "All," that issue is deemed to be a 'National' issue.

3. NERC and NAESB will develop Standards for resolving all National Issues.

4. If the 'Region 1' and 'Region 2' fields for a specific issue list specific markets (e.g. PJM & MISO) that issue is deemed to be a 'Regional' issue.

5. The 'Resp Org' currently considering a Regional 'Issue Type' will initially be the identified 'Regions' or an organization that represents those 'Regions.'
   - Regional seams solutions may only apply to the impacted regions.
   - Regional reliability issues are governed by NERC and/or a NERC Regional Council.

6. Entities involved in a Regional Issue may elect to submit a Standard Request to NAESB to develop a Standard.
   - NAESB can, and will, develop Standards with regional deference.

Seams Issues Matrix

(As Adopted at NAESB WEQ Meeting)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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		National	NAESB	NAESB		Transactions between and through RTOs and needs to be consistent. Needs to be developed in a single forum.
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		Regional	PJM/MISO	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper	
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.	Regional	PJM/MISO	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
35	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	Locational Marginal Prices (LMP) at borders of RTOs with markets (Price cap included)		National	NAESB	NAESB		
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	

Seams Issues Matrix

(As Adopted at NAESB WEQ Meeting)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
129	Congestion Management	Congestion Management Market Coordination		Selection process for market/TLR coordinated flowgates; inclusion of flowgates in PJM FTR/ARR 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.	Regional	PJM/MISO	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.	National	NAESB	NAESB	Yes	Business practices complimentary to NERC Policy 9 and 5, or subsequent standards. High priority.
125	Congestion Management	Determining Control Area Boundaries		Retention of former CAs in the model	When expanding Control Area boundaries (i.e., merging Control Areas) is it necessary to retain "Historic" boundaries for use in NNL estimation or other reasons?	Regional	PJM/MISO	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper	
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)	Regional	Western Interconect SSG-WI	NERC	SSG-WI, CMA Work Group	
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		Regional	PJM/MISO	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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	National	NERC	all	Limited	High priority. All associated commercial impacts should be referred to NAESB.
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.	Regional	NYISO/ISO-NE	NYISO/ISO-NE	Northeast ISO	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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	National	NERC	NERC	Limited	High priority. All associated commercial impacts should be referred to NAESB.
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.	Regional	HQ TransÉnergie /NYISO/ISO-NE	NERC	No	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.

Seams Issues Matrix

(As Adopted at NAESB WEQ Meeting)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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 #I.a.2)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
9	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Transmission Calculations	Transmission calculations are not consistent. Solution: Standardized ATC Calculations.	National	NAESB	NERC	Yes - SSG - WI	High priority. All associated commercial impacts should be referred to NAESB.
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.	Regional	NYISO/ISO-NE	NERC	Northeast ISO	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.		Regional	PJM/ NYISO/ ISO-NE	NERC	In Northeast Power Markets Seams Action Plan	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.		Regional	PJM/MISO	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
20	Congestion Management	Standardize TTC 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.	National	NERC	NERC	Yes	All associated commercial impacts should be referred to NAESB.
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)	Regional	Western Interconect SSG-WI	all	SSG-WI, CMA Work Group	
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	National	NERC	NERC	Limited	
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)	Regional	Western Interconect SSG-WI	NERC	SSG-WI, CMA Work Group	
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…).	Regional	PJM/MISO	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	
123	Congestion Management	System Market Modeling Coordination		GDLF calculation	Standardized methodology for determining distribution factors - standard OPF model for each interconnection?	Regional	PJM/MISO	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	

Seams Issues Matrix

(As Adopted at NAESB WEQ Meeting)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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		Regional	PJM/MISO	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper	Possible NERC reliability issue.
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.	Regional	PJM/MISO	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper	
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.		Regional	PJM/ NYISO/ ISO-NE	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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	Regional	Western Interconnect SSG-WI	Western Interconnect SSG-WI	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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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).	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
131	Market Design	Energy Market Design and Coordination		Express sunset provisions for implementation of Day 2 markets		Regional	PJM/MISO	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper	

Seams Issues Matrix

(As Adopted at NAESB WEQ Meeting)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
113	Market Design	Green Power Market		Green power attributes trading		National	NAESB	NAESB	In Northeast Power Markets Seams Action Plan	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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 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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.	National	NAESB	NAESB	Yes / IIPTF	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	all	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.

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Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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.	National	NAESB	NERC	Yes / IIPTF	All associated commercial impacts should be referred to NAESB. Action complementary to NERC efforts.
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.	National	NAESB	NERC	Yes / IIPTF	All associated commercial impacts should be referred to NAESB. Action complementary to NERC efforts.
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".		National	NAESB	NERC		All associated commercial impacts should be referred to NAESB. Action complementary to NERC efforts.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
134	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Compensation for parallel flows		National	NAESB	NAESB	In PJM/MISO Congestion Management Proposal Whitepaper	All associated commercial impacts should be referred to NAESB. Action complementary to NERC efforts.
142	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	Pricing for native load loop flow impacts		Regional	Multiple	Multiple	No	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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.	Regional	Multiple	Multiple	Yes - SSG - WI	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
3	Market Standards	Energy Market Standard Product Definitions		Definition & treatment of Firm/nonfirm Power	Annual Plan Item 4ci moved from MOS	National	NAESB	all	No	NAESB to take lead on definition development in cooperation with other resp. orgs.
10	Market Standards	Energy Market Standard Product Definitions		Energy Products	Entities have disagreements concerning the definitions of various energy products. Solution: Standardized Energy Products.	National	NAESB	NAESB	Yes - WECC	NAESB to take lead on definition development in cooperation with other resp. orgs.
25	Market Standards	Energy Market Standard Product Definitions		Need for common physical market and products regional variations permitted		National	NAESB	NAESB	No	NAESB to take lead on definition development in cooperation with other resp. orgs.

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Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
34	Market Standards	Energy Market Standard Product Definitions		Clarification of Product Definitions	Complete/Standard definitions for Liquidated Damages (LD), "Into", etc.	National	NAESB	NAESB	No	NAESB to take lead on definition development in cooperation with other resp. orgs.
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	National	NAESB	NAESB	Yes	NAESB to take lead on definition development in cooperation with other resp. orgs.
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.	Regional	Western Interconnect	Western Interconnect	No	See comments under org. #42 and #52.
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.	National	NAESB	NAESB	Yes	NAESB currently working on issue.
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	National	NAESB	NAESB	Limited	NAESB currently working on issue.
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)	Regional	Western Interconect SSG-WI	all	SSG-WI, CMA Work Group	
140	Market Standards	Market Standard Communication Protocols and Transparency		Standard messaging protocols for market notifications	Market participants will benefit from common messaging protocols.	National	NAESB	NAESB	No	NAESB currently working on issue.
1	Market Standards	Market Standard Operating Time		Non Standard Time Zone	The lack of a standard Time Zone causes Market Inefficiencies	National	NAESB	NAESB	No	
136	Market Standards	Market Standard Operating Time		Inconsistent Market Event Timelines	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.	Regional	IMO/MISO	NPCC/ ECAR	No	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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).	Regional	IMO/NYISO	IMO/NYISO	No	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.	National	NAESB	NAESB	Yes / IIPTF	NAESB currently working on issue.
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)		Regional	PJM/ NYISO/ ISO-NE	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan	
46	Planning	Transmission Expansion and Generator Interconnection Coordination	Generator Interconnection - Affected Systems	Generation Interconnection Studies	Generation Interconnections close to seam affects both areas	National	NAESB	all	Limited	FERC Order 2003 addressed issue.

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Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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	Regional	Multiple	Multiple	Northeast ISO	FERC Order 2003 addressed issue.
114	Planning	Transmission Expansion and Generator Interconnection Coordination	Interregional Transmission Planning Procedures	Coordination of interregional planning including transmission facilities and generator interconnection procedures		Regional	Multiple	NERC	In Northeast Power Markets Seams Action Plan	Changed from National/NAESB entry.
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 PJM/MISO.	Regional	Multiple	Multiple	Yes	
48	System Reliability	Emergency Operations	Computer Failures	Communication of Computer Failures	Needed for reliable operations and emergency operations	National	NERC	NERC	Limited	
49	System Reliability	Emergency Operations	Emergency Operating Procedures for Market Interfaces	Emergency Procedures	Emergency procedures require operations across seams	National	NERC	NERC	Limited	All associated commercial impacts should be referred to NAESB. Action complementary to NERC efforts.
128	System Reliability	Emergency Operations	System Monitoring and Contingency Plans	Contingency plans; critical path analysis		National	NERC	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	All associated commercial impacts should be referred to NAESB. Action complementary to NERC efforts.
118	System Reliability	Emergency Operations	System Restoration Procedures	Emergency and Restoration Plans - operating procedures for Voltage Collapse and Stability		National	NERC	NERC	Included in Attachment A of MISO and PJM Reliability Plans	All associated commercial impacts should be referred to NAESB. Action complementary to NERC efforts.
122	System Reliability	Functional Model		Control area - control zone responsibilities vs. market operator		National	NERC	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	
50	System Reliability	Generation-Load Balance	Interchange Schedule Ramping Requirements	Schedule Ramp Management	Ramping standard differences across the seams hinder business	National	NAESB	NERC	Limited	
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.		Regional	PJM/ NYISO/ ISO-NE	all	In Northeast Power Markets Seams Action Plan	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.	National	NERC	NERC	Limited	Other Resp. org. may be involved.
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	National	NERC	NERC	Yes	All associated commercial impacts should be referred to NAESB.
45	System Reliability	Inter-Market and Intra-Market Facility Outage and Maintenance Coordination		Coordination of Transmission and Generation Outages	Both forced and planned outages	National	NERC	NERC	Limited	All associated commercial impacts should be referred to NAESB.

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Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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		Regional	PJM/MISO	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.		National	NERC	NERC		All associated commercial impacts should be referred to NAESB. Action complementary to NERC efforts.
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).	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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).	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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		National	NERC	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	All associated commercial impacts should be referred to NAESB.
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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.		Regional	PJM/ NYISO/ ISO-NE	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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		Regional	PJM/MISO	NERC	In PJM/MISO Congestion Management Proposal Whitepaper	

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Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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		Regional	PJM/MISO	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper	
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.	Regional	PJM/MISO	NERC	Yes	Currently being addressed on a regional basis. Potential for North American standardization with regional deference. All associated commercial impacts should be referred to NAESB.
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	National	NERC	NERC	Yes	All associated commercial impacts should be referred to NAESB.
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	National	NERC	NERC	No	All associated commercial impacts should be referred to NAESB.
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	Regional	NYISO/ISO-NE/PJM	NERC	Yes	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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 JCAG) needs to be formed to review the draft Concept of Operations to provide stakeholder input.	Regional	NYISO/ISO-NE	NYISO/ISO-NE	Northeast ISO	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.	Regional	NYISO/ISO-NE	NYISO/ISO-NE	Northeast ISO	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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	National	NAESB	NAESB	Yes - WECC	NAESB already addressing this issue.
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.	National	NAESB	NERC	Yes	NAESB already addressing this issue.
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)	National	NAESB	NAESB	SSG-WI, CMA Work Group	NAESB already addressing this issue.
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)	National	NAESB	all	SSG-WI, CMA Work Group	NAESB already addressing this issue.

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Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
8	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Scheduling	Inconsistent procedures among entities. Solution: Western Interconnection Standardized Interchange Scheduling Protocols.	Regional	Multiple	Multiple	Yes - SSG - WI	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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)	Regional	Western Interconect SSG-WI	all	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.		National	NAESB	NAESB	In Northeast Power Markets Seams Action Plan	All associated commercial impacts handled by NAESB. Action complementary to NERC efforts.
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.		National	NAESB	NAESB	In Northeast Power Markets Seams Action Plan	All associated commercial impacts handled by NAESB. Action complementary to NERC efforts.
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 my be a non paying transmission customer.		Regional	PJM/MISO	PJM/MISO		Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.	Regional	NYISO/ISO-NE/PJM	NYISO/ISO-NE/PJM	Yes	
4	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Definition & treatment of Firm/nonfirm Transmission	Annual Plan Item 4cii moved from MOS	National	NAESB	all	No	NAESB to take lead on definition development in cooperation with other resp. orgs.
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.		National	NAESB	NAESB	In Northeast Power Markets Seams Action Plan	
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		Regional	PJM/MISO	PJM/MISO	In PJM/MISO Congestion Management Proposal Whitepaper	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
141	Transmission Service	Transmission Market Standard Product Definitions and Priorities		Replacement of contract path with flow-based transmission service		Regional	Multiple	Multiple	No	National / must be at least interconnect wide.
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.	Regional	NYISO/ ISO-NE	NYISO/ ISO-NE	Northeast ISO	
22	Transmission Service	Transmission Service Pricing	Market Interface Transmission Service Pancaking	Rate pancaking elimination	Being reviewed by PJM/MISO.	Regional	PJM/MISO	PJM/MISO	Yes	Policy issue before FERC with national implications.
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	Regional	NYISO/ISO-NE	NYISO/ISO-NE	Yes	Policy issue before FERC with national implications.

Seams Issues Matrix

(As Adopted at NAESB WEQ Meeting)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Description of Seam Issue	Comments	Issue Type	Resp Org	NERC Choice	Currently Being Addressed	NAESB Support
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.		Regional	PJM/ NYISO/ ISO-NE	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan	Policy issue before FERC with national implications.
117	Transmission Service	Transmission Service Procurement	Common Reservation System for Market Interface Transmission ATC	Contract Tie Capacity - One Stop Shopping		Regional	NAESB	NAESB	No	NAESB already addressing this issue (OASIS 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.	Regional	Multiple	NAESB	Yes - Various Transmission Providers	
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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
33	Transmission Service	Transmission Service Procurement	Intra-Hour Transmission Service Procurement	Standard for Purchasing of Intra-Hour Transmission	The ability to purchase transmission after the top of the hour when the transmission service is predetermined as available in prior hour.	National	NAESB	NAESB	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)	Regional	Western Interconect SSG-WI	Western Interconect SSG-WI	SSG-WI, CMA Work Group	
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)	Regional	Multiple	Multiple	SSG-WI, CMA Work Group	Currently being addressed on a regional basis. Potential for North American standardization with regional deference.
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.		Regional	PJM/ NYISO/ ISO-NE	PJM/ NYISO/ ISO-NE	In Northeast Power Markets Seams Action Plan	
28	Transmission Service	Transmission Service Settlement	Consolidate Multiple Market Transmission Service Settlement Statements	Multiple transmission service charge invoicing	Being reviewed by PJM/MISO.	National	NAESB	NAESB	Yes	Related to issue #56.
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.	Regional	NYISO/ISO-NE	NYISO/ISO-NE	Northeast ISO	Currently being addressed on a regional basis. Potential for North American standardization with regional deference. Related to issue #28.

Column Headings:

A **Original Number** - The number originally assigned the seam issue. Used to track each issue as it was categorized and re-categorized.

B **Category** - Seam issues are grouped into one of 8 categories:

1. Congestion Management
2. Market Design
3. Market Monitoring / Compliance
4. Market Standards
5. Planning
6. System Reliability
7. Transaction Scheduling
8. Transmission Service

C **1st Sub-Category** - The seam issues categories are further delineated into 1st sub-categories.

D **2nd Sub-Category** - The seam issue 1st sub-categories are even further delineated into 2nd sub-categories.

E **Description Of Seam Issue** - Brief description of the seams issue.

F **Comments** - Additional comments providing background or further definition of the seam issue.

***** **Association / Notes** - Identification of associated seam issues based on their Original Number. (Ed. Note: this column was eliminated once seams issues were categorized).

***** **Seam Interface Type** - Each seam interface has 2 acting parties. Here the market status relationship between the 2 acting parties are identified, e.g., RTO Market to RTO Market, RTO Market to Non-RTO Market, Non-RTO Market to Non-RTO Market. (Ed. Note: this column was eliminated once seams issues were categorized).

G **Resp Org Cobb** - Recommended assignment by Steven Cobb, Salt River Project.

H **Resp Org IRC** - Recommendd assignment by Karl Tammar, NYISO, as representative of the IRC.

I **Resp Org Mueller** - Recommeded assignment by Ken Brown and Jeff Mueller, PSEG.

J **Issue Type** - Categorization of seams issue as either "national" or "regional" in scope.

K **Responsible Organization** - The recommended organization to be assigned a seam issue by the NERC / NAESB / IRC Joint Interface Committee (JIC).

L **Region 1** - The RTO, ISO, or Non-RTO Market Region that is the 1st acting party to the seam issue is identified here.

M **Region 2** - The RTO, ISO, or Non-RTO Market Region that is the 2nd acting party to the seam issue is identified here.

N **Priority** - The organization assigned a seam by the NERC / NAESB / IRC Joint Interface Committee (JIC) will use this column to prioritize their efforts.

O **Seam Impediment Type** - Identification of what causes the seam issue, e.g., market rule, business practice, physical barrier.

P **Currently Being Addressed** - Identification of another body that is currently working on the seam issue.

Q **Submitter** - The name of the person and organization providing the matrix information.

R **Reference Papers** - If reference papers are provided to support the information, a letter is assigned to the document. The index of reference papers appears at the end of the matrix.

#	Reference Paper or Supporting Document Provided
A	“Profit-Enhancing Seam Management: A White Paper on Pricing The Unscheduled Flows of Electricity Across the Seams Between Utilities Using A Geographically Differentiated Auction of Inadvertent Interchange”, released 2001 March 25 (Mark Lively - Lively Utility).
B	"WOLF: Wide Open Load Following," A presentation to the NERC Market Interface Committee, 2002 September 4-5, Houston, Texas (Mark Lively - Lively Utility).
C	E-Mail by Mark Lively to NAESB WEQ Seams Subcommittee of 9/4/2003 8:28:10 PM Eastern Standard Time (Mark Lively - Lively Utility).
D	See the PJM/MISO JOA dated 8/5/03 (Linda Horn - WE Energies).
E	MISO - PJM Managing Congestion to Address Seam Paper, April 28, 2003 (Dave Nick - DTE Energy) (Ed. note: white paper updated Aug. 4, 2003).
F	*Intentionally Left Blank.*
G	Northeast ISOs Seams Resolution Report: History of Seam Issues Resolution (Jan. 15, 2003); and Ongoing Northeast ISOs "Seams" Projects, 2003-2004 (Jan. 14, 2003) (Joe Rossignoli - National Grid).
H	In Northeast Power Markets Seams Action Plan - October 9, 2002 and July 14, 2003, and July 3, 2003 timeline update (Jeff Mueller - PSEG).
I	Attachement A of MISO and PJM Reliability Plans (Jeff Mueller - PSEG).
J	MISO compliance filings in FERC Docket No. EL03-35-004 and in Whitepaper "Managing Congestion to Address Seams" PJM and MISO May 16, 2003 (Jeff Mueller - PSEG).
K	ATC's Attachment K (Jeff Mueller - PSEG).
L	M. Lively, Forcing Reserves to Compete with a Physical Market (2002) (Lou Oberski -- Dominion Energy).

Seams Issues Matrix

(Items of Disagreement at JIC)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Issue Type	Resp Org	NERC Choice
36	Congestion Management	Congestion Management Market Coordination	Coordinate Hedging Instruments at Market Interfaces	National	NAESB	NAESB
115	Congestion Management	Congestion Management Market Coordination	Standardize Congestion Management Market Data Exchange	Regional	PJM/MISO	NERC
35	Congestion Management	Congestion Management Market Coordination	Standardize Prices at Market Interfaces	National	NAESB	NAESB
129	Congestion Management	Congestion Management Market Coordination		Regional	PJM/MISO	NERC
73	Congestion Management	Operate Markets Within Transmission Limits		Regional	Western Interconect	NERC
43	Congestion Management	Standardize and Coordinate ATC Calculations	Contract Tie Capacity Sharing	National	NERC	all
17	Congestion Management	Standardize and Coordinate ATC Calculations and Postings	Reconcile ATC Calculations Between Physical and Financial Transmission	Regional	HQ TransÉnergie	NERC
9	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		National	NAESB	NERC
55	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Regional	NYISO/ISO-NE	NERC
109	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Regional	PJM/ NYISO/ ISO-NE	NERC
116	Congestion Management	Standardize and Coordinate ATC Calculations and Postings		Regional	PJM/MISO	NERC
69	Congestion Management	System Market Modeling Coordination	Standardize Prices at Market Interfaces	Regional	Western Interconect	all
75	Congestion Management	System Market Modeling Coordination		Regional	Western Interconect	NERC
121	Congestion Management	System Market Modeling Coordination		Regional	PJM/MISO	NERC
123	Congestion Management	System Market Modeling Coordination		Regional	PJM/MISO	NERC

Seams Issues Matrix

(Items of Disagreement at JIC)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Issue Type	Resp Org	NERC Choice
113	Market Design	Green Power Market		National	NAESB	NAESB
16	Market Design	Transmission Ancillary Service Market Design and Coordination	Reactive Power Compensation	National	NAESB	NAESB
74	Market Design	Transmission Ancillary Service Market Design and Coordination		Regional	Western Interconect	all
13	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	National	NAESB	NERC
15	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	National	NAESB	NERC
29	Market Design	Unscheduled/Parallel Path Flow Management	Compensation for Unscheduled/Parallel Path Flow	National	NAESB	NERC
3	Market Standards	Energy Market Standard Product Definitions		National	NAESB	all
71	Market Standards	Market Standard Communication Protocols and Transparency		Regional	Western Interconect	all
136	Market Standards	Market Standard Operating Time		Regional	IMO/MISO	NPCC/ ECAR
46	Planning	Transmission Expansion and Generator Interconnection	Generator Interconnection - Affected Systems	National	NAESB	all
114	Planning	Transmission Expansion and Generator Interconnection	Interregional Transmission Planning Procedures	Regional	Multiple	NERC
50	System Reliability	Generation-Load Balance	Interchange Schedule Ramping Requirements	National	NAESB	NERC
108	System Reliability	Generation-Load Balance	Interchange Schedule Ramping Requirements	Regional	PJM/ NYISO/ ISO-NE	all
120	System Reliability	Inter-Market and Intra-Market Facility Outage and Maintenance		Regional	PJM/MISO	NERC
126	System Reliability	Unscheduled/Parallel Path Flow Management	Interchange Distribution Calculator Requirements	Regional	PJM/MISO	NERC

Seams Issues Matrix

(Items of Disagreement at JIC)

Orig #	Category	1ST Sub-Category	2ND Sub-Category	Issue Type	Resp Org	NERC Choice
23	System Reliability	Unscheduled/Parallel Path Flow Management	Parallel Path/ Unscheduled Flow Monitoring and Operation	Regional	PJM/MISO	NERC
39	Transaction Scheduling	Controllable Line Scheduling		Regional	NYISO/ISO-NE/PJM	NERC
41	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Inter-Market Ramping Requirements Standardization	National	NAESB	NERC
78	Transaction Scheduling	Interchange Scheduling Standardized Protocols	Tools and Procedures to Accommodate Inter-Market	National	NAESB	all
76	Transaction Scheduling	Interchange Scheduling Standardized Protocols		Regional	Western Interconect	all
4	Transmission Service	Transmission Market Standard Product Definitions and Priorities		National	NAESB	all
6	Transmission Service	Transmission Service Procurement	Common Western Interconnection Wide OASIS	Regional	Multiple	NAESB

TAB 8

Transition Issues – NERC Policies 3, 5, 9

Policy 5 — Emergency Operations

Version 3

Replaced OSL with IRL

Policy Subsections

A. Coordination with Other Operating Authorities
B. Insufficient Generating Capacity
C. Transmission System Relief
D. Separation from the Interconnection
E. System Restoration
F. Disturbance Reporting

Add req't for Operating Authority to have situational awareness.

Introduction

The OPERATING AUTHORITY is responsible for operating its systems in a safe and reliable manner to ensure reliable service of its end-use customers.

From Appendix 9D

The integrity and reliability of the interconnected power system is of paramount importance, and shall take precedence above all other aspects including commercial operations. OPERATING AUTHORITIES shall operate within proven secure power system parameters at all times. Should the OPERATING AUTHORITY enter an unknown operating state, it shall immediately restore operations to respect proven secure power system parameters.

Need reasonable implementation time.

OPERATING AUTHORITIES shall inform other potentially affected OPERATING AUTHORITIES and those throughout the interconnection of real time or anticipated emergency conditions to facilitate emergency assistance, and take actions to avoid where possible, or mitigate the emergency.

OPERATING AUTHORITIES shall immediately take appropriate action to relieve any abnormal real time conditions that jeopardize reliable interconnected power system operation. These actions may include firm load shedding. Neighboring OPERATING AUTHORITIES shall render all available emergency assistance requested, provided that the requesting OPERATING AUTHORITY has implemented its comparable emergency procedures.

If two Op Authorities do not agree, operate to the most conservative limits.

Each OPERATING AUTHORITY ~~and Region~~ shall establish a program of system operator controlled manual and automatic load shedding which is designed to arrest declining frequency, transmission interface overloads, or voltage decays that could result in an uncontrolled failure of components of the interconnected bulk electric system. The program shall be coordinated throughout each Interconnection to prevent unbalanced load shedding which may cause high transmission loading and extreme frequency and/or voltage deviations.

The Operating Authority is responsible for implementing the actions ~~identified~~ directed by the RELIABILITY COORDINATOR to protect the RELIABILITY COORDINATOR AREA. If the OPERATING AUTHORITY believes that a RELIABILITY COORDINATOR directive may harm the OPERATING AUTHORITY'S equipment or creates a public safety hazard, the OPERATING AUTHORITY and RELIABILITY COORDINATOR will arrive at a mutually agreeable solution that will mitigate these concerns and result in the reliable operation of the RELIABILITY AREA.

From Appendix 9D. Added language to deal with disagreements.

A. ~~Coordination with Other Operating Authorities~~Operating Authority Responsibilities

[Appendix 7A – Instructions for Interregional Emergency Telephone Networks]

Requirements

Need to compare with FERC Order 2003. Sec. 14

1. **Bulk Power System.** The Operating Authority shall not remove Bulk ~~power~~ Power ~~system~~ System facilities from service if removing those facilities would burden neighboring Operating Authorities unless:

1.1. ~~If bulk electric power facilities must be removed from service,~~ T~~t~~he Operating Authority ~~must~~ first notifies~~y~~ the adjacent Operating Authorities and coordinates the impact resulting from the removal of the Bulk Power System facility. ~~[**add words for coordination**].~~ or,

~~**1.2.**~~When time does not permit such notification and coordination, or when immediate action is required to prevent hazard to the public, sustained customer service interruption, or damage to facilities, the Operating Authority shall notify adjacent Operating Authorities at the earliest possible time to ensure Operating Authority coordination.

2. The Operating Authority shall comply with Control Performance Standards [see Policy 1A] during an emergency. The Operating Authority shall coordinate interchange schedule changes as needed to maintain reliability.

3. The Operating Authority shall observe normal facility ratings unless there is insufficient generating capacity to comply with Control Performance Standards, or insufficient reactive resources in the Operating Authority Area, in which case emergency transfer capabilities may be used prior to shedding firm load.

3.1. The Operating Authority shall ensure that emergency transfer capabilities shall not be exceeded to the extent possible.

3.1.1. In emergency transfer capabilities are exceeded, the Operating Authority shall take immediate corrective action, up to and including load shedding, to return flow below the emergency transfer capability.

3.2. The Operating Authority shall operate within the System Operating Limits and Interconnection Reliability Limits

4. Each Control Area shall maintain automatic generation control equipment operational and in service. [See also Policy 1E, "Automatic Generation Control Standard"]

5. The Operating Authority shall immediately restore the real and reactive power balance by implementing such control actions as reconfigure the transmission, redispatch generation, voltage reduction, load transfers. ~~between load and source. [Need to rewrite this. What "balance?" Between "load and source?" Need to capture the concept of reactive reserves and capacity.]~~ If the Operating Authority remains unable to restore its real and reactive power balance it shall request emergency assistance from neighboring

and adjacent Operating Authorities. If emergency assistance is not adequate to mitigate the real and reactive power balance, than load shedding shall be implemented.

6. The Operating Authority shall immediately reduce the effects of power flows through other Operating Authority Areas if those flows have been identified as contributing to an operating emergency (e.g., resulting in SOL or IRL violations) in those other Operating Authority Areas. [See Policy 9, "Reliability Coordinator Procedures" for further information on using local or Interconnection-wide transmission loading relief procedures]

7. ~~When Operating Authority has taken all possible action (see list below and incorporate next paragraph in here) unable to [add language: cannot comply with Control Performance Standards or return its system to SOL or IRL] within its Operating Authority area, that Operating Authority shall request for assistance from neighboring Operating Authorities. Upon receiving a request for assistance from another Operating Authority to mitigate an emergency, the Operating Authority shall provide available assistance within the requested timeframe.~~

~~**7.1.** Assistance shall be requested only after comparable action(s) has been implemented by the requesting Operating Authority(s). Assistance may include, but is not limited to, and in no implied order of priority:~~

~~**7.2.** Redispatching generation (may be subject to agreements). =~~

~~**7.3.** Providing reactive support.~~

~~**7.4.** Curtailing non-firm energy transfers to non-affected Operating Authorities~~

~~**7.5.** Supplying capacity and energy to the Operating Authority experiencing the emergency~~

~~**7.6.** Redistribution or sharing of operating reserve.~~

~~**7.7.** Shedding interruptible load where permitted by a power system's internal policy.~~

~~**7.8.** Implementing voltage reduction.~~

~~**7.9.** Loading facilities to their emergency transfer capabilities provided that adverse weather conditions do not prevent such assistance.~~

~~**7.10.** Any other actions that would mitigate the operating emergency.~~

8. Upon receiving a request for assistance from another Operating Authority to mitigate an emergency, the Operating Authority shall provide available assistance within the requested timeframe. Assistance shall be requested only after comparable action(s) has been implemented by the requesting Operating Authority(s). Assistance may include, but is not limited to, and in no implied order of priority:

8.1. Redispatching generation (may be subject to agreements).

8.2. Providing reactive support.

8.3. Curtailing non-firm energy transfers to non-affected Operating Authorities

8.4. Supplying capacity and energy to the Operating Authority experiencing the emergency

8.5. Redistribution or sharing of operating reserve.

8.6. Shedding interruptible load where permitted by a power system's internal policy.

8.7. Implementing voltage reduction.

8.8. Loading facilities to their emergency transfer capabilities provided that adverse weather conditions do not prevent such assistance.

8.9. Any other actions that would mitigate the operating emergency.

8.10.

9.

B. Communications and Coordination

Requirements

1. **Communication and Coordination**. Reliable inter-area and intra-area voice communications shall be available for the Operating Authorities, as appropriate to their accountabilities. Adequate communications (voice and data links) such as priority communication paths to appropriate entities which are staffed and available to act in addressing a real time emergency condition., ~~with an availability at least equivalent to that provided by a dedicated and redundant circuit.~~ Operating Authorities ~~Notifying~~ notifying other Operating authorities shall inform their Reliability Coordinator and ~~a~~all other potentially affected operating authorities through predetermined communication paths.

Procedures for the calls need to be developed to ensure that orderly calls are conducted. Primary moderator should have back-up moderators available. Use of Hotline needs further clarification. Hotline not used for local load shedding. Save it for Interconnection problem identification and usage.

1.1. **Hotline use.** When a condition is identified that could threaten the reliability of the Interconnection or when firm load shedding is anticipated, the affected OPERATING AUTHORITY, via its RELIABILITY COORDINATOR, shall utilize the Interconnection-wide telecommunications network in accordance with Appendix 7A — Regional and Interregional Telecommunication, Subsection A, "NERC Hotline," to convey the following ~~at~~ information to others in the Interconnection:~~.~~

~~1.2.~~1.1.1. **Insufficient resources.** The OPERATING AUTHORITY is unable to purchase capacity to meet its load and reserve requirements on a day-ahead and hour by hour basis.

~~1.3.~~1.1.2. ~~**Lack of single contingency coverage.**~~ **System Operating Limit or Interconnected Reliability Limit violation.** Line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection. (Once a single contingency occurs, the OPERATING AUTHORITY must prepare for next contingency~~)~~

~~1.4.~~1.1.3. **Emergency actions for inability to purchase capacity or energy.** A 3% or greater voltage reduction, public appeals for load curtailments, or firm load shedding is anticipated due to an inability to purchase emergency capacity/energy.

~~1.5.~~1.1.4. **Emergency actions for other reasons.** Implementation of 3% or greater voltage reduction, public appeals for load reduction, or firm load shedding for other than local problems.

~~1.6.~~1.1.5. **Sabotage incident.** The system suspects or has identified a multi-site sabotage occurrence, or single-site sabotage of a critical facility.

C. Insufficient Generating Capacity

Introduction

Rewrote Intro based on meeting dicsussion.

During a system emergency, the Operating Authority must continue to comply with NERC Control Performance and Disturbance Control Standards as explained in Policy 1, "Generation Control and Performance," regardless of costs. In other words, the Operating Authority may not rely on the frequency bias of the other CONTROL AREAS in the Interconnection to provide energy during the emergency because doing so reduces the Interconnection's ability to recover its frequency following additional generator failures.

If the Operating Authority can not comply with the Control Performance and Disturbance Control standards, then it must immediately implement remedies to do so. These include, but are not limited to:

1. Requesting assistance from other Control Areas
2. Declearing an Energy Emergency through its Reliability Coordinator
3. Load reduction, such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

Requirements

1. A CONTROL AREA anticipating an operating capacity emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

2. **Returning ACE to Acceptable Levels.** In the event of a capacity deficiency, generation and transmission facilities shall be used to the fullest extent practicable to restore normal system frequency and voltage and return ACE to acceptable performance criteria as defined in Policy 1E. Using bias variables to "cover up" problems is prohibited.

Policy 1 should be revised to require operation within a tolerance of - 500 MW or 2 x L(10) for 30 minutes.

2.1. Under Generation Condition.

~~2.1.~~2.1.1. Schedule assistance. The deficient ~~system~~ Operating Authority shall schedule all available assistance that is required with as much advance notice as possible.

~~2.2.~~2.1.2. Using Interconnection's bias. The deficient ~~system~~Operating Authority ~~shall~~ ~~may~~shall only use the assistance provided by the Interconnection's frequency bias ~~only~~ for the time needed to implement one or more of the following:

~~2.2.1.~~2.1.2.1. Operating reserve. Utilize its readily available operating reserve.

~~2.2.2.~~2.1.2.2. Available resources. Use all resources available to the deficient system. The deficient Operating Authority shall declare an Emergency Energy Alert in accordance with Appendix 5B.

~~2.2.3.~~2.1.2.3. **Emergency Procedures.** Utilize emergency procedures including:

~~2.2.3.1.~~2.1..2..3.1. Internal emergency procedures ~~up to and including firm load shedding~~

~~2.2.3.2.~~2.1..2..3.2. Emergency assistance from ~~others~~ others

2.1..2..3.3. Firm load shedding

3. Elevating Transmission Service Priority. When a TRANSMISSION PROVIDER expects to elevate the transmission service priority of an INTERCHANGE TRANSACTION from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff **[**See **Appendix 9C1, "Transmission Loading Relief Procedure"** for explanation of Transmission Service Priorities**]**

3.1. Declaring Energy Emergency Alert. The LOAD-SERVING ENTITY served by the CONTROL AREA or TRANSMISSION PROVIDER must request its RELIABILITY COORDINATOR to initiate an ENERGY EMERGENCY ALERT. **[See Appendix ~~9B~~5B, "Energy Emergency Alerts"]**

3.1.1. Posting EEA on Web. This Alert must be posted on the NERC Web site, and include the expected total MW that may have its TRANSMISSION SERVICE priority **changed.**

3.2. Forecasting change in service priority. EEA 1 will be used to *forecast* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.

3.3. Announcing change in service priority. EEA 2 will be used to *announce* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.

4. Emergency action. If all other steps prove inadequate to relieve the capacity/energy emergency, the deficient control area shall take immediate action, which includes, but is not limited to, the following:

4.1. Schedule all available emergency assistance from other Control Areas.

4.2. Implement manual firm load shedding.

5. Unilateral action. The Control Area shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and interchange schedule changes. Such unilateral adjustment may jeopardize overloaded transmission facilities.

C. Transmission System Relief

Introduction

This policy:

1. Summarizes the authority, information and tools required by SYSTEM OPERATORS responsible for the reliability of the INTERCONNECTIONS.

2. Identifies the accountability for developing and implementing procedures to alleviate INTERCONNECTED RELIABILITY LIMIT violations.

3. Describes the requirement to develop procedures for the curtailment and restoration of transmission service.

Requirements

1. **Relieving System Operating Limit violations.** Each CONTROL AREA experiencing or contributing to an INTERCONNECTED RELIABILITY LIMIT violation shall take immediate steps to relieve the condition which may include firm load shedding.

2. **Operator authority and responsibility.** SYSTEM OPERATORS having responsibility for the reliability of the transmission system within a CONTROL AREA, pool, etc. shall have and shall exercise specific authority to alleviate INTERCONNECTED RELIABILITY LIMIT violations. The authority shall enable the SYSTEM OPERATOR to take timely and appropriate actions including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

3. **Action shall not reduce reliability.** Action to correct an SOL OR IRL violation shall not cause an SOL or IRL violation in neighboring and adjacent Operating Authority areas. ~~someplace else.~~ Furthermore, this action shall not damage interconnected generation or transmission equipment,

This is necessary to protect equipment that could not be readily replaced, or would hinder system restoration if it were destroyed. However the Operating Authority must have an operating plan to ensure that taking the facility out of service does not cause an SOL or IRL violation elsewhere.

3.1. **Disconnection of overloaded equipment.** ~~[Put subject first "the OA" shall]~~ The affected Operating Authority shall disconnect the affected facility i~~I~~f the overload on a transmission facility or abnormal voltage/reactive condition persists and equipment is endangered~~, the affected Operating Authority may disconnect the affected facility~~. Neighboring Operating Authorities and Reliability Coordinators impacted by the disconnection shall be notified prior to switching, if time permits, otherwise, immediately thereafter.

4. **System Operating Limit violation assessment.** The Control Area shall have sufficient information and analysis tools to determine the cause(s) of SYSTEM OPERATING LIMIT violations. This analyses shall be conducted in all operating timeframes. The system operator shall use the results of these analyses to immediately mitigate the SOL violation. [The Reliability Coordinator is responsible for assessing the system for IRL violations,]

Comment: Coordinate this requirement with that imposed on the Reliability Coordinator in Policy 9 and Appendix 9D

D.Separation from the Interconnection (This guide is not needed.)

Introduction

Because the facilities of each system may be vital to the secure operation of the INTERCONNECTION, systems and CONTROL AREAS shall make every effort to remain connected to the INTERCONNECTION. However, if a system or CONTROL AREA determines that it is endangered by remaining interconnected, it may take such action as it deems necessary to protect its system

The RCWG and ORS recommends deletion of this section of Policy 5 since it contains no requirements.

If a portion of the interconnection becomes separated from the remainder of the INTERCONNECTION, abnormal frequency and voltage deviations may occur. To permit resynchronizing, relief measures shall be applied by those separated systems contributing to the frequency and voltage deviations.

Guides(This guides seem to be addressing the promotion of keeping interconnected)

Load shedding to prevent separation. The Operating Authority shall have an emergency load reduction plan for all identified IRLs. The plan shall include the details on how the Operating Authority will implement load reduction in sufficient amount and time to mitigate the IRL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

1.Generator shutdown. If abnormal levels of frequency or voltage resulting from an area disturbance make it unsafe to operate the generators or their support equipment in parallel with the system, their separation or shutdown should be accomplished in a manner to minimize the time required to re-parallel and restore the system to normal.

1.1.Separating generators with local load. If feasible, generators should be separated with some local, isolated load still connected. Otherwise, generators should be separated carrying their own auxiliaries.

2.AGC. AGC should remain operative if practicable. (How is this going to help? Would want to be on frequency control, and not tie-line bias control.)

3.Instructions for plant operators. Plant operators should be supplied with instructions specifying the frequency and voltage below which it is undesirable to continue to operate generators connected to the system. (Something was developed for Y2K.)

4.Generator protection at high and low frequency. Protection systems should be considered for automatically separating the generators from the system at predetermined high and low frequencies.

D. System Restoration

[Policy 6D – Operations Planning–System Restoration]
[System Restoration and Blackstart Procedures Reference Document]

Introduction

After a system collapse, restoration shall begin when it can proceed in an orderly and secure manner. Systems and CONTROL AREAS shall coordinate their restoration actions. Restoration priority shall be given to the station supply of power plants and the transmission system. Even though the restoration is to be expeditious, system operators shall avoid premature action to prevent a re-collapse of the system.

Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency as the system is restored.

Requirements

1. Returning to normal operations. Following a disturbance in which one or more system areas become isolated, steps shall begin immediately to return the system to normal:

1.1. Extent of isolated system. The ~~system operator~~Operating Authority shall determine the extent and condition of the isolated area(s).

1.2. Frequency restoration. The ~~system operator~~Operating Authority shall then take the necessary action to restore system frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.

1.3. Interchange schedule review. Interchange schedules between CONTROL AREAS or fragments of CONTROL AREAS within the separated area shall be immediately reviewed and appropriate adjustments made in order to gain maximum assistance in restoration. Attempts shall be made to maintain the adjusted schedules whether generation control is manual or automatic.

1.4. Resynchronizing. When voltage, frequency and phase angle permit, the ~~system operator~~Operating Authority may resynchronize the isolated area(s) with the surrounding area(s), properly notifying adjacent systems, and considering the size of the area being reconnected and the capacity of the transmission lines effecting the reconnection. (Restoration plan should consider the number of synchronizing points across the system.) (Covered in policy 6)

Review Policy 9 (coordination with RC) and the System Restoration document (Role of RC in restoration).

1.5. Off-site supply for nuclear plants. Restoration of off-site power to nuclear stations shall be given high priority.

1.6. Load Restoration. Synchronizing one Control Area to another, may need to shed load during the re-synchronizing process in order to prevent burdening the other system.

Guides

1. **Isolating loads to help restoration.** In order to systematically restore, loads without overloading the remaining system, opening circuit breakers should be considered to isolate loads in blacked-out areas.

2. **Restoration.** Load shed during a disturbance should be restored utilizing approve Restoration Procedures that will maintain the integrity of the control area and Interconnection.

   2.1. **Manual restoration.** Load may be restored manually or by supervisory control only by direct action or order of the ~~system operator~~Operating Authority as generating and transmission capacity become available.

   2.2. **Automatic restoration.** Automatic load restoration may be used where feasible to minimize restoration time.

      2.2.1. **Coordination.** Load restoration should be coordinated with neighboring systems, coordinated areas, and Regions.

      2.2.2. **Must not burden others.** Load restoration should not aggravate system frequency excursions, overload tie lines, or burden any system in the Interconnection.

3. **Oil-filled cables.** Reenergizing oil-filled pipe-type cables should be given special consideration, especially if loss of oil pumps could cause gas pockets to form in pipes or potheads.

4. **Maintaining transmission voltage.** The following should be considered when trying to maintain normal transmission voltage during restoration:

   4.1. **Preventing excessive voltage.** Removal of shunt capacitors or addition of reactors or addition of small blocks of isolated load to prevent excessive voltage when energizing long transmission lines.

   4.2. **Energizing cables.** Effects of energizing high-voltage cables at the end of a long, lightly loaded system.

   4.3. **Reactive considerations.** The capability of the generators to provide or absorb reactive power flows.

F. Disturbance Reporting

[Appendix 5F – Reporting Requirements for Major Electric System Emergencies]

Introduction

Disturbances or unusual occurrences that jeopardize the operation of the interconnected systems, and result, or could result, in system equipment damage, or customer interruptions, must be studied in sufficient depth to increase industry knowledge of electrical interconnection mechanics to minimize the likelihood of similar events in the future. It is important that the facts surrounding a disturbance shall be made available to RELIABILITY COORDINATORS, system and CONTROL AREA operators, system managers, Regional Councils, NERC, and regulatory agencies entitled to the information.

Requirements

1. **Regional Council Reporting Procedures.** Each Regional Council shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.

2. **Analyzing disturbances.** Bulk system disturbances shall be promptly analyzed by the affected systems.

3. **Disturbance reports.** Based on the NERC and DOE disturbance reporting requirements, those systems responsible for investigating the incident shall provide a preliminary written report to their Regional Council and NERC.

3.1. **Preliminary written reports.** Either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnected Reliability Limit and Preliminary Disturbance Report form shall be submitted by the affected system(s) within 24 hours of the disturbance or unusual occurrence. Certain events (e.g. near misses) may not be identified until some time after they occur. Events such as these should be reported within 24 hours of being recognized.

3.2. **Preliminary reporting during adverse conditions.** Under certain adverse conditions, e.g. severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnected Reliability Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected entity(ies) shall notify its Regional Council(s) and NERC promptly and verbally provide as much information as is available at that time. The affected utility(ies) shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

3.3. **Final written reports.** If in the judgment of the Regional Council, after consultation with the electric system(s) in which a disturbance occurred, a final report is required, the affected electric system(s) shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Council approval.

4. **Notifying NERC.** The NERC Disturbance Reporting Requirements, shown in **Appendix 5F, Sections A and B**, are the minimum requirements for reporting disturbances, unusual occurrences, and voltage excursions to NERC.

5. **Notifying DOE.** The U.S. Department of Energy's most recent Emergency Incident and Disturbance Reporting Requirements, outlined in **Appendix 5F, Section C,** are the minimum

requirements for U.S. utilities and other entities subject to Section 13(b) of the Federal Energy Administration Act of 1974. Copies of these reports shall be submitted to NERC at the same time they are submitted to DOE.

6. **Assistance from NERC Operating Committee (OC) and the Disturbance Analysis Working Group (DAWG).** When a bulk system disturbance occurs, the Regional Council's OC and DAWG representatives shall make themselves available to the system or systems immediately affected to provide any needed assistance in the investigation and to assist in the preparation of a final report.

7. **Final report recommendations.** The Regional Council shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Council tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Council shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Council has taken to accelerate implementation.

Policy 6 — Operations Planning

Version 2, Draft 2

Policy Subsections

A. Normal Operations
B. Emergency Operations
C. Automatic Load Shedding
D. System Restoration
E. Control Center Backup

Introduction

Each ~~system, CONTROL AREA, and Region~~ OPERATING AUTHORITY ~~is responsible for maintaining~~must maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Operating Authority is responsible for using available personnel and system equipment to implement these plans to assure that interconnected systems reliability will be maintained.

System operations personnel shall ~~seek to~~ participate in the system planning and design study process so that these studies will contain the operators' perspective and the operators will know the intended planning purpose.

(Policy is very high level and uses vague language. Language can be interpreted however the reader would like. Hard to monitor compliance. For example what is the operations planning time horizon? Clarification of what operations planning should be undertaken by CAs versus RCs. Policy may be grossly out dated.)

A. Normal Operations

~~Criteria~~Introduction

~~Each control area shall plan its future operations in coordination with other affected control areas so that normal interconnection operation will proceed in an orderly and consistent manner.~~

Requirements

1. Each control area shall plan its current-day, next-day, and seasonal operations in coordination with neighboring control areas so that normal interconnection operation will proceed in an orderly and consistent manner. The control area shall coordinate its current-day, next-day, and seasonal operations with all Operating Authorities within its operating area, and its associated Reliability Coordinator.

2. **Planning to meet loads.** Each control area shall plan to be able to meet

   4.1. Daily load patterns

   4.2. Changes in system load characteristics

   4.3. Real reserves

   4.4. Voltage and/or reactive profiles

   4.5. Interchange schedules

   4.6. Generation and transmission maintenance management

   4.7. System limits

2. **System studies.** Control Areas shall work in conjunction with facility asset owners within its Control Area boundary to determine System Operating Limits. The Control Area shall ensure that their locally derived System Operating Limits are within simultaneous interconnected transfer capabilities. The results of these system studies ~~pertinent to operations~~ shall be available to the Control Area ~~system~~ operators.

3. **Total Transfer Capability Determination.** Each control area shall utilize the asset owner determined facility ratings to determine the power transfer capabilities within its area and to identify potential operating problems.

4.1. **Determining transfer capability.** Inter-Control Area transfer capability studies shall respect internal and external System Operating Limits. Generating unit and transmission facility outage patterns shall be considered. Studies shall determine additional reactive requirements resulting from reasonable generation and transmission contingencies.

4. **Generator capability verification.** Generating capability verification shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity.

5. **Communication of facility status.**

4.1. Generator asset operators shall immediately notify their Control Area operators of changes in capabilities and characteristics including but not limited to:

5.1.1. Changes in real and reactive output capabilities,

5.1.2. Automatic Voltage Regulator status and mode setting

4.2. Generation asset operators shall provide a forecast of expected real power output to their Control Areas to assist in operations planning at the Control Area's request (e.g. a seven-day forecast of real output).

4.3. Transmission asset operators shall notify their Control Area operators of changes in capabilities and characteristics including but not limited to:

5.3.1. Changes in transmission facility status

5.3.2. Changes in transmission facility rating

4.4. Control Area operators shall communication facility status information to their Reliability Coordinator.

6. Computer models. Control Areas shall maintain accurate computer models utilized for analyzing and planning system operations.

~~**2.Studies of limits and procedures.** Appropriate up-to-date studies shall be used as a reference for establishing transmission limits and normal and emergency operating procedures including those for line and equipment loading relief.~~

~~**4.1.Load relief procedures.** Line and equipment loading relief procedures shall involve those Transmission Operating Entities that have an impact on the overloaded facilities.~~

~~**4.2.Access to information.** Participants of line and equipment loading relief procedures shall have access to monitored power flows that impact the reliability of the participants transmission system.~~

Guides

~~**1.Planning for transfers.** Planned energy transfers should be reviewed ahead of time and compared with expected loads and established transfer limits to ensure that the transfers will not cause any system to violate established reliability criteria.~~

~~**2.Long-range plans.** Reviews should be made with planning engineers periodically to ensure that the long-range plans will allow for compliance with the NERC Operating Policies.~~

~~**3.Studies with other systems.** Each control area should participate in studies with other systems, when required, to consider:~~

~~**4.1.Facilities.** The facilities on each system, which may affect the operation of the coordinated area.~~

~~**4.2.Generation limits.** The operating limitations of generating facilities.~~

~~**4.3.Transmission limits.** The operating limitations of the system when all transmission facilities are in service.~~

~~**4.4.Operating limits.** The operating limitations of the system when transmission facilities are scheduled or forced out of service.~~

3.5.4.1. ~~Voltage and reactive schedules.~~

~~**4.Transfer studies between systems.** Studies should be made annually (or at such times as bulk system changes warrant) to determine the transfer capability between interconnected control areas.~~

~~**5.Generator capability studies.** Generating capability determination should include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity.~~

~~**6.Transfer studies within system.** Each control area should determine the power transfer capabilities of its transmission system and identify potential problems by conducting operating studies as required.~~

~~**6.1.4.2. Determining ratings.** Thermal, stability, short- and long-term loading, and voltage limits, plus seasonal (temperature) characteristics, should be considered when determining the ratings on transmission facilities.~~

~~**4.2.Determining transfer capability.** Transfer capability studies should consider voltage, reactive, thermal, and stability limits of internal and external system equipment. (Ref: "Transmission Transfer Capability, A Reference Document," NERC May 1995) Generating unit and transmission facility outage patterns should be considered. Studies should determine additional reactive requirements resulting from reasonable generation and transmission contingencies.~~

~~**7.Computer models.** Computer models utilized for analyzing and planning system operations should be renewed and updated as necessary to ensure that they accurately and adequately represent the system.~~

~~**8.**~~7. ~~**Uniform line identifiers.** Neighboring systems should use uniform line identifiers and ratings when referring to transmission facilities of an interconnected network.~~

B. Emergency Operations

Criteria

A set of plans consistent with NERC Operating Policies shall be developed, maintained, and implemented as required by each system, control area, pool, and Region to cope with operating emergencies (none of the requirements deal with operating emergencies, mostly just capacity and energy requirements). These plans shall be coordinated with other systems, control areas, pools, and Regions as appropriate. (Perhaps this section of Policy 6 should be merged with policy 5.)

Requirements

1. **Agreements for emergency assistance.** Operating agreements between neighboring systems or pools shall contain appropriate provisions for emergency assistance, including provisions to obtain emergency assistance from remote systems or pools.

2. **Ability to execute procedures.** Plans developed and maintained to cope with operating emergencies shall include procedures that can be executed by system operators.

Move these 3 requirements into Policy 5A.

3. **Authority to shed load.** Each system shall give its system operators the authority to implement manual load shedding when necessary.

Guides

1. **Capacity and energy emergency plans.** Each system or pool should develop capacity and energy emergency plans that will enable it to mitigate, to the fullest extent possible, the effect of a capacity or energy emergency on its customers.

   1.1. Appropriate governmental agencies should be apprised of the plans.

2. **Plans shall include...** The capacity and energy emergency plans should include or consider the following items: This list is not complete. What about reserve sharing and shared activation of reserves?

   2.1. Coordinating functions. The functions to be coordinated with and among neighboring systems.

   2.2. Fuel supply and inventory. An adequate fuel supply and inventory plan which recognizes reasonable delays or problems in the delivery or production of fuel.

   2.3. Fuel switching. Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

   2.4. Environmental constraints. Plans to seek removal of environmental constraints for generating units and plants.

   2.5. System energy use. The reduction of the system's own energy use to a minimum.

Do any of these guides need to be moved to the requirements section?

2.6. **Public appeals.** Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

2.7. **Load management.** Implementation of load management and voltage reductions, if appropriate.

2.8. **Optimize fuel supply.** The operation of all generating sources to optimize the availability

2.9. **Appeals to customers to use alternate fuels.** In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

2.10. **Interruptible and curtailable loads.** Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

2.11. **Maximizing generator output and availability.** The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

2.12. **Notifying IPPs.** Notification of cogeneration and independent power producers to maximize output and availability.

2.13. **Requests of government.** Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

2.14. **Load curtailment.** A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

2.15. **Notification of government agencies.** Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

3. **Coordination of emergency plans.** Each Region, system, and/or pool should participate in the coordination of capacity and energy emergency plans and actions to maximize mutual aid during such emergencies. The following steps should be taken:

3.1. **Communications.** Establish and maintain reliable communications between interconnected systems.

3.2. **Interchange agreements.** If existing interchange agreements cannot be used, new agreements should be arranged to provide for emergency capacity or energy transfers.

3.3. **Maintenance coordination.** Coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

3.4. **Energy deliveries.** Arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Automatic Load Shedding

Criteria

After taking all other remedial steps, a system or control area whose integrity is in jeopardy due to insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components of the interconnection. (Perhaps this section of Policy 6 should be merged with policy 5.)

Requirements

1. Plans for automatic load shedding. Each system shall establish plans for automatic load shedding.

1.1. Coordination. Load shedding plans shall be coordinated among the interconnected systems.

1.2. Frequency or voltage level. Automatic load shedding shall be initiated at the time the system frequency or voltage has declined to an agreed-to level.

1.2.1. Load shedding steps. Automatic load shedding shall be in steps related to one or more of the following: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels.

1.2.2. Minimizing risk. The load shed in each step shall be established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

1.2.3. Underfrequency load shedding on separation. After a system or control area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, additional load shall be shed manually.

1.2.4. Coordination with generator, et al, tripping. Automatic load shedding shall be coordinated throughout the Region with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions which will occur under abnormal frequency, voltage, or power flow conditions.

Guides

1. Load shedding studies. Automatic load shedding plans should be based on studies of system dynamic performance, simulating the greatest probable imbalance between load and generation.

1.1. Unacceptable results. Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result.

1.1.1. Action on overfrequency. If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

1.1.2. Action on overvoltage. If overvoltages are likely, the load shedding program should be modified to minimize that probability.

2. **Local area considerations.** When scheduling load to be shed automatically, the system should consider its local area requirements and transmission capabilities between areas.

3. **Automatic isolation plan.** A generation-deficient control area may establish an automatic isolation plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the Interconnection. This isolation plan may be used only with the consent of neighboring systems, and if it leaves the remaining bulk electric system intact.

D. System Restoration

[Policy 5E – Emergency Operations–System Restoration]

Criteria

Each system, control area, and Region shall develop and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of the system. This plan shall be coordinated with other control areas in the interconnection to assure a consistent Interconnection restoration plan.

A reliable and adequate source of startup power for generating units shall be provided. Where sources are remote from the generating unit, instructions shall be issued to expedite availability. Generation restoration steps shall be verified by actual testing whenever possible.

System restoration procedures shall be verified by actual testing or by simulation. (Perhaps this section of Policy 6 should be merged with policy 5.) Perhaps have one standard

Requirements

1. **Restoration plan.** Each system shall establish a restoration plan with necessary operating instructions and procedures to cover emergency conditions, including the loss of vital telecommunications channels.

    1.1. **Restoration plan update.** The restoration plan shall be updated, as necessary, to reflect changes in the power system network and to correct deficiencies found during the simulated restoration exercises.

    1.2. **Restoring the Interconnection.** Restoration plans must be developed with the intent of restoring the integrity of the Interconnection.

    1.3. **Coordination.** Restoration plans shall be coordinated with neighboring systems.

    1.4. **Testing telecommunications.** Telecommunication facilities needed to implement the plan shall be periodically tested.

2. **System operator training.** Operating personnel shall be trained in the implementation of the plan. Such training should include simulated exercises, if practicable.

3. **Procedure testing.** System restoration procedures shall be verified by actual testing or by simulation.

Guides

1. **Operation at abnormal voltage and frequency.** Generators and their auxiliaries should be able to operate reliably at abnormal voltages and frequencies.

2. **Generator shutdown and restart.** Emergency sources of power should be available to facilitate safe shutdown, enable turning gear operation, minimize the likelihood of damage to either generating units or their auxiliaries, maintain communications, and expedite restarting.

3. **Emergency power source.** Each generating plant should have a source of emergency power to expedite restarting.

3.1. Hydroelectric plants should have internal provisions for restarting.

3.2. Station service busses. Where station service generators are used in parallel with the system, station auxiliary busses should be separated automatically from the system before the frequency has decayed sufficiently to adversely affect the station service units.

3.3. Station service and area security. The effect of station service generators on area security should be considered before they are shut down for economy.

3.4. Outside startup power source. Where an outside source of power is necessary for generating unit startup, switching procedures should be prearranged and periodically reviewed with system operators and other operating personnel.

4. **Startup and shutdown plans.** Each control area should have written plans for orderly start-up and shutdown of the generating units.

4.1. **Updates.** These plans should be updated when required.

4.2. **Drills.** Drills should be held periodically to assure that plant operators are familiar with the plans.

5. **Blackstart testing.** Periodic tests should be made to verify blackstart capability.

6. **Synchroscope calibration.** All synchroscopes should be calibrated in degrees, and phase angle differences at interconnection points should be communicated in degrees.

7. **Synchronizing locations and procedures.** System operators should know the preplanned synchronizing locations and procedures. Procedures should provide for alternative action to be taken in case of lack of information or loss of communication channels that would affect resynchronizing.

8. **Protection systems.** Proper protection systems should be considered in the restoration sequence. Relay polarization sources should be maintained during the process.

9. **Telecommunications considerations.** Backup voice telecommunications facilities, including emergency power supplies and alternate telecommunications channels, should be provided to assure coordinated control of operations during the restoration process.

10. **Master trip points.** Control centers using SCADA systems should consider providing master trip points for each station to expedite the restoration process.

E. Control Center Backup

Criteria

Each control area shall have a plan to continue operation in the event its control center becomes inoperable. (Perhaps this section of Policy 6 should be merged with policy 5.)

Guides

1. **Must not burden the Interconnection.** The standards of Policy 1 should be considered when developing the plan to continue operation so that the control area will not be a burden to the Interconnection if its own control center becomes inoperable.

1.1. **Location of backup center.** If the control area has a backup control center, it should be remote from the primary control center site.

Policy 9 – Reliability Coordinator Procedures

Version 3

Subsections

A. Next Day Operations Planning Process
B. Current Day Operations – Energy
C. Current Day Operations – Transmission

Terms

Operating Authority. An entity that:

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission ~~security~~reliability, and/or emergency preparedness, and

2. Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies, and

3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

Reliability Coordinator Area. That portion of the Bulk Electric System under the purview of the RELIABILITY COORDINATOR.

Operating Authority Area. That portion of the Bulk Electric System under the purview of the OPERATING AUTHORITY.

Introduction

This document contains the process and procedures that the NERC RELIABILITY COORDINATORS are expected to follow to ensure the operational reliability of the INTERCONNECTIONS. These include:

- Planning for next-day operations, including reliability analyses (such as pre- and post-contingency thermal monitoring, system reserves, area reserves, reactive reserves, voltage decline, stability, etc.) and identifying special operating procedures that might be needed,
- Analyzing current day operating conditions, and
- Implementing procedures (local, Interconnection-wide, or other) to mitigate ~~overloads or limit~~ System Operating Limit and Interconnected Reliability Limit violations on the transmission system. Regardless of the process, the Reliability Coordinator must ensure their Control Areas return their transmission system to within ~~Operating Security Limits~~Interconnected Reliability Limits as soon as possible, but no longer than 30 minutes as indicated in Policy 2.

Operating Authorities shall not burden others. The RELIABILITY COORDINATOR shall ensure that all OPERATING AUTHORITIES ~~shall~~ will operate to prevent, contain, and minimize the likelihood that a disturbance, action, or non action in one area ~~could~~will ~~adversely affect another party's system or any system~~result in a SYSTEM OPERATING LIMIT or INTERCONNECTED RELIABILITY LIMIT VIOLATION in another area of ~~in~~ the Interconnection. Doing otherwise is considered a "burden" that one Operating Authority places on another. The Bulk Electric System shall be operated to the most conservative parameter, if Reliability Coordinator study results differ??.

Operating under known conditions. OPERATING AUTHORITIES shall ensure they operate their systems under known conditions at all times and also ensure they reprepare their systems following contingency events within approved timelines, regardless of the number of contingency events that occur.

A. Next Day Operations Planning Process

When disseminating system analysis information, RELIABILITY COORDINATORS are expected to comply with the provisions of NERC's "Confidentiality Agreement for Electric System Reliability." **[Appendix 4B]**

Requirements

1. **Performing security analysis.** The RELIABILITY COORDINATOR shall conduct next-day reliability analyses for its Reliability Area to ensure that the bulk power system can be operated in anticipated normal and contingency conditions.

1.1. **Sharing information.** Each CONTROL AREA in the RELIABILITY AREA shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known INTERCHANGE TRANSACTIONS. This information shall be available by 1200 Central Standard Time for the Eastern INTERCONNECTION, and 1200 Pacific Standard Time for the Western INTERCONNECTION.

Does this need to go into Policy 6 also? Aimed at the CA.

1.2. **Performing system Studies.** The RELIABILITY COORDINATOR shall conduct contingency analysis-based studies to identify potential interface and other INTERCONNECTED RELIABILITY LIMIT violations, including overloaded transmission lines and transformers, voltage and stability limits, etc. Particular attention should be given to parallel flows to ensure one ~~area~~ RELIABILITY AREA does not place an unacceptable or undue burden on an adjacent ~~entity~~ RELIABILITY AREA.

1.3. **Developing action plans.** The RELIABILITY COORDINATOR shall develop action plans that may be required including reconfiguration of the transmission system, redispatching of generation, reduction or curtailment of INTERCHANGE TRANSACTIONS or reduce firm load to maintain transmission loading within acceptable limits.

2. **Sharing study Results**. The RELIABILITY COORDINATOR shall share the results of its system studies, when conditions warrant or upon request, with other RELIABILITY COORDINATORS, ~~TRANSMISSION PROVIDERS,~~ and ~~CONTROL AREAS~~OPERATING AUTHORITIES within their RELIABILITY AREA. Study results shall be available no later than 1500 Central Standard Time for the Eastern INTERCONNECTION, and 1500 Pacific Standard Time for the Western INTERCONNECTION, unless circumstances warrant otherwise. ~~If the results of these studies indicate potential reliability problems, the RELIABILITY COORDINATORS shall issue the appropriate alerts via the Reliability Coordinator Information System (RCIS) and direct their OPERATING AUTHORITIES to take any necessary action the RELIABILITY COORDINATOR deems appropriate to address the potential reliability concern. OPERATING AUTHORITIES shall comply with their Reliability Coordinator's direction.~~

3. **Communication of next day reliability concerns.**

3.1. Any time that conditions warrant, a conference call or other appropriate communications shall be initiated by any RELIABILITY COORDINATOR to address whatever problems are revealed by the reliability analyses.

3.2. If the results of these studies indicate potential reliability problems, the RELIABILITY COORDINATORS shall issue the appropriate alerts via the Reliability Coordinator Information System (RCIS) and direct their OPERATING AUTHORITIES to take any

necessary action the RELIABILITY COORDINATOR deems appropriate to address the potential reliability concern. OPERATING AUTHORITIES shall comply with their Reliability Coordinator's direction.

~~3.~~4. OPERATING AUTHORITIES shall comply with their Reliability Coordinator's direction.

5. ~~**Identifying special operating procedures.** Potential~~The ~~RELIABILITY COORDINATOR shall identify special o~~perating procedures ~~that may be required shall be identified, including reconfiguration of the transmission system, redispatching of generation, reduction or curtailment of INTERCHANGE TRANSACTIONS or if necessary, a plan to reduce firm load to maintain transmission loading within acceptable limits.~~

B. Current Day Operations – Energy

[Appendix 5B, Subsection A, "Energy Emergency Alerts"]

Requirements

1. ~~Analyzing~~ **Monitoring CONTROL AREA generation resource availability.** The RELIABILITY COORDINATOR shall ~~analyze~~ monitor generation resource availability and reserve levels for the CONTROL AREAS, RESERVE-SHARING GROUPS, and LOAD-SERVING ENTITIES in its RELIABILITY ~~COORDINATOR~~ AREA to determine any actual or potential energy deficiencies. The RELIABILITY COORDINATOR is expected to direct its OPERATING AUTHORITIES to take whatever action the RELIABILITY COORDINATOR deems appropriate to address the potential reliability concern. OPERATING AUTHORITIES shall comply with their RELIABILITY COORDINATOR'S direction.

2. **Authority to provide emergency assistance.** The RELIABILITY COORDINATOR shall have the authority to take or direct whatever action is needed to mitigate an energy emergency within ~~his~~ its RELIABILITY AREA including load shedding. OPERATING AUTHORITIES shall ensure the direction of the RELIABILITY COORDINATOR is implemented as directed. ~~This action includes all resources in the RELIABILITY COORDINATOR'S footprint including load shedding if so directed. OPERATING AUTHORITIES shall ensure the direction of the RELIABILITY COORDINATOR is implemented as directed.~~ Reliability Coordinators shall provide assistance to other Reliability Coordinators experiencing an emergency in accordance with Appendix 5B, Subsection A, "Energy Emergency Alerts."

~~3.Notifying~~ **Communication of Energy Emergencies** ~~**others**~~. Each RELIABILITY COORDINATOR that is experiencing a potential or actual energy emergency within any CONTROL AREA, RESERVE-SHARING GROUP, or LOAD-SERVING ENTITY within ~~his~~ its RELIABILITY AREA shall initiate an ENERGY EMERGENCY ALERT as detailed in **Appendix 5B, Subsection A – "Energy Emergency Alert Levels."** The RELIABILITY COORDINATOR shall also act to ~~address the emergent condition~~ to mitigate ~~the~~ emergency condition, including a request for emergency assistance if required.

3. **Determining causes of Interconnection** FREQUENCY ERROR**.** Any~~ny~~ ~~RELIABILITY COORDINATOR~~FREQUENCY MONITOR noticing an Interconnection Frequency Error in excess of 0.03 Hz (Eastern Interconnection) or 0.05 Hz (Western and ERCOT Interconnections) for more than 20 minutes shall initiate a Reliability Coordinator Hotline conference call, or notification via the RCIS, to determine the Control Area(s) with the energy emergency or control problem.

   3.1. If a RELIABILITY COORDINATOR determines there is a reliability issue related to one or more of its CONTROL AREAS' contributing to the Frequency Error, the associated RELIABILITY COORDINATOR shall direct the CONTROL AREA(S) to immediately balance its system by using all resources available to it, including load shedding. The OPERATING AUTHORITY(S) shall comply with the Reliability Coordinator request.

Is this requirement too burdensome to RCs?

C. Current Day Operations – Transmission

[Policy 3A, "Interchange – Interchange Transaction Implementation"]
[Appendixes 9C1, 9C2, 9C3, "Transmission Loading Relief Procedures]

Requirements

1. **INTERCHANGE TRANSACTION information.** The RELIABILITY COORDINATOR shall be aware of all INTERCHANGE TRANSACTIONS that wheel-through, source or sink in ~~the~~ its RELIABILITY ~~COORDINATOR~~ AREA and make that INTERCHANGE TRANSACTION information available to all RELIABILITY COORDINATORS in the INTERCONNECTION. (Note: This requirement is satisfied by the Interchange Distribution Calculator and E-Tag process for the Eastern Interconnection.)

~~1.1.~~2. ~~Notifying~~ Communication with **RELIABILITY COORDINATORS of potential problems.** The RELIABILITY COORDINATOR who foresees a transmission problem (such as an Interconnected Reliability Limit violation, loss of reactive reserves, etc.) within its RELIABILITY ~~COORDINATOR~~ AREA shall issue an alert to all CONTROL AREAS and Transmission Providers in its RELIABILITY ~~COORDINATOR~~ AREA, and all RELIABILITY COORDINATORS within the INTERCONNECTION via the RCIS[1] without delay.

3. **Implementing relief procedures.** If transmission loading progresses or is projected to progress beyond the System Operating Limit or ~~OPERATING RELIABILITY LIMIT~~INTERCONNECTED RELIABILITY LIMIT, the RELIABILITY COORDINATOR will perform the following procedures as necessary:

~~Subsections rearranged for better "flow."~~Definitions of SOL and ILR included in Glossary of Terms

~~2.1.Managing INTERCHANGE TRANSACTIONS.~~ ~~The RELIABILITY COORDINATORS will continue to manage INTERCHANGE TRANSACTIONS through their respective CONTROL AREAS during this period to help mitigate the INTERCONNECTED RELIABILITY LIMIT violation.~~

2.1 isn't clear. What does "manage" mean? Combine this with 2.2?

~~2.2.~~3.1. **Selecting transmission loading relief procedure.** The RELIABILITY COORDINATOR experiencing a constraint on a transmission system within ~~his~~ its RELIABILITY AREA shall, at his discretion, select from either a "local" (Regional, Interregional, or subregional) transmission loading relief procedure or an INTERCONNECTION-wide procedure, such as those listed in Appendix 9C1, 9C2, or 9C3.

~~2.2.1.~~3.1.1. **Using local transmission loading relief procedure.** The RELIABILITY COORDINATOR may use local transmission loading relief or congestion management procedures, provided the transmission system experiencing the constraint is a party to those procedures.

~~2.2.1.1.~~3.1.1.1. **Using with an Interconnection-wide Procedure**. A Reliability Coordinator may implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, he is obligated to follow the curtailments as directed by the Interconnection-wide procedure. If the Reliability Coordinator desires to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure, he may

[1] Reliability Coordinator Information System

do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee[2].2

~~2.2.1.2.Updating the IDC. The Reliability Coordinator must enter, or have entered on his behalf, into the IDC all Interchange Transaction changes that result from the implementation of the local procedure. [Eastern Interconnection Requirement]~~

Still and RC requirement? No. This requirement should be addressed in Policy 3.

~~2.2.2.~~3.1.2. **Using an INTERCONNECTION-wide loading relief procedure.** The RELIABILITY COORDINATOR may implement an INTERCONNECTION-wide procedure as detailed in Appendixes 9C1, 9C2, or 9C3.

~~2.2.2.1.~~3.1.2.1. **Complying with procedures.** When implemented, all RELIABILITY COORDINATORS shall comply with the provisions of the INTERCONNECTION-wide procedure. This may include action by RELIABILITY COORDINATORS in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.

~~2.2.3.~~3.1.3. **Complying with Interchange Policies.** During the implementation of relief procedures, and up to the point that emergency action is necessary, RELIABILITY COORDINATORS and CONTROL AREAS shall comply with the Requirements of Policy 3, "Interchange."

~~2.3.Managing transmission service. The RELIABILITY COORDINATORS shall direct their those OPERATING AUTHORITIES who are providing transmission service to discontinue selling transmission service that exacerbates the OSL Interconnected Reliability Limit violation during the period of heavy loading.~~

Capture this concept in Policy 6 (ATC/AFC coordination).

~~2.4.~~3.2. **Mitigating System Operating Limit and Interconnected Reliability Limit Violations.** Regardless of the process used the RELIABILITY COORDINATOR must direct its OPERATING AUTHORITIES to return ~~its~~ the transmission system to within ~~Operating Security Limits~~ System Operating Limits and INTERCONNECTED RELIABILITY LIMITS as soon as possible, but no longer than 30 minutes as indicated in Policy 2. With this in mind, RELIABILITY COORDINATORS and their OPERATING AUTHORITIES must be aware that Transmission Loading Relief procedures may not be able to address the transmission issue in a timely fashion. Under these circumstances other actions such as reconfiguration, redispatch or load shedding may be necessary until the relief requested by the TLR process is achieved. In these instances the Reliability Coordinator shall direct, and entities shall comply with the more timely requests.

~~3.~~4. **Implementing emergency procedures.** If the RELIABILITY COORDINATOR deems that the transmission loading condition ~~is deemed critical to~~ is placeings the bulk electric system reliability at an immediate risk ~~by a RELIABILITY COORDINATOR~~, the RELIABILITY COORDINATOR

The point is that the BES is at "an immediate risk" and the RC must act now.

[2] Examples would be 1) a local procedure that curtails INTERCHANGE TRANSACTIONS in a different order or ratio than the INTERCONNECTION-wide procedure, or 2) a local redispatch procedure.

shall haves the authority and obligation to immediately direct the CONTROL AREAS in its RELIABILITY AREA to redispatch generation, reconfigure transmission, manage INTERCHANGE TRANSACTIONS , or reduce system demand[3], or if directed, shed firm load to mitigate the critical conditionimmediate risk until INTERCHANGE TRANSACTIONS can be reduced utilizing a transmission loading relief procedure, or other procedures, to return the system to a reliable state. The RELIABILITY COORDINATOR shall coordinate these emergency procedures with other RELIABILITY COORDINATORS as appropriateneeded. All CONTROL AREAS shall comply with all directives from their RELIABILITY COORDINATOR as authorized by the Regional Reliability Plan.[4] **[See also Policy 5, "Emergency Operations"]**

4.5. Reestablishing normal operations. Once the System Operating Limit or Interconnected Reliability Limit violation or other operating emergency has been mitigated, tThe Reliability Coordinator may take the following actions in whatever order is appropriate:

4.1.5.1. Reestablishing Interchange Transactions. The RELIABILITY COORDINATOR shall coordinate with the Control AreasOPERATING AUTHORITIES in its Reliability Area, and with other RELIABILITY COORDINATORS as appropriate, the reestablishment of the INTERCHANGE TRANSACTIONS that were curtailed. The reestablishment of these INTERCHANGE TRANSACTIONS and the resulting INTERCHANGE SCHEDULES shall be in compliance with Policy 3, "Interchange.

4.2.5.2. Restoring system dispatch. The Reliability Coordinator shall notify its OPERATING AUTHORITIES that they may reestablish their normal resource dispatch.

4.3.5.3. Reestablishing Load. The Reliability Coordinator shall coordinate with the Control AreasOperating Authorities in their its Reliability Area, and with other RELIABILITY COORDINATORS as appropriate, the reestablishment of the firm loads that were curtailed.

6. Compliance with Reliability Coordinator Directives. All Operating Authorities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment or regulatory/statutory requirements. Under these circumstances the Operating Authorities must immediately inform the Reliability Coordinator of the inability to perform the directive so that alternate remedial actions may be implemented.

[3] The Reliability Coordinator may use any number of methods to reduce system demand, including shedding firm load. The Reliability Coordinator must also consider the location of the demand reduction to ensure its effectiveness in reducing the transmission loading.

[4] Compliance with directives must consider public safety and equipment limits and good utility practice.

Appendix 9D – Reliability Coordinator Criteria and ~~Functions~~Tasks

Version 4, Draft 2

Functions → Tasks

Remove "proper" and "appropriate"

Appendix Subsections

A. Criteria for Reliability Coordinators
B. Tasks of Reliability Coordinators

Terms

From Terms section of Manual. Can keep here as well.

Operating Authority. An entity that:

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission ~~security~~reliability, and/or emergency preparedness, and

2. Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies, and

3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

Reliability Coordinator Area. That portion of the Bulk Electric System under the purview of the RELIABILITY COORDINATOR.

Operating Authority Area. That portion of the Bulk Electric System under the purview of the OPERATING AUTHORITY.

Wide Area. The entire RELIABILITY COORDINATOR AREA as well as that critical flow and status information from adjacent RELIABILITY COORDINATOR AREAS as determined by detailed system studies to allow the calculation of Interconnected Reliability Limits.

New def of Wide Area from our meeting. Added highlighted words.

Introduction

Reliability Coordinators shall have the capability to monitor their responsibilities with a wide area view perspective and calculate Interconnection Reliability Operating Limits. Wide area is described as the ability to monitor the complete Reliability Coordinator footprint (as listed above) and may include critical flow and status information from adjacent footprints as determined by detailed system studies. With this in mind it is likely that Reliability Coordinators will develop IROL conditions not normally seen by Transmission Operators.

A. ~~Criteria for Reliability Coordinators~~Reliability Coordinator Criteria

1. Responsibilities.

Suggest reorganizing this section. See pages 6-7 for suggested organization outline.

1.1. Reliability Coordinator responsibilities. The RELIABILITY COORDINATOR is responsible for having the wide area view, the operating tools, processes and procedures to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions. The Reliability Coordinator shall have clear decision-making authority to act or direct others to act to preserve the integrity and reliability of the bulk electric system. **The RELIABILITY COORDINATOR may not delegate its responsibilities to other OPERATING AUTHORITIES or entities.**

1.2. Operating Authority responsibilities to the Reliability Coordinator. The Operating Authority~~, such as Control Areas, have the responsibility to implement~~is responsible for implementing the actions identified by the RELIABILITY COORDINATOR to protect the ~~Interconnection~~RELIABILITY AREA.

Copied into Policy 5 Intro

1.3. Operating Authority responsibilities for its own area. ~~Control Areas~~The OPERATING AUTHORITY ~~have the responsibility~~is responsible for operating its systems in a safe and reliable manner to ensure reliable service of their end use customers. (MOVE TO ANOTHER POLICY)

2. Delegating tasks. ~~The responsibilities of a Reliability Coordinator cannot be delegated.~~ The Reliability Coordinator may delegate tasks, as indicated in section "B," ~~may be delegated~~ to other Operating Authorities and entities, but this delegation ~~require~~ must be accompanied by formal operating agreements ~~to~~ and ensure those tasks are ~~properly~~ understood, communicated, and addressed by all Operating Authorities within the Reliability Area and not just the signatories to those agreements.

2.1. Designating delegation. The Regional Reliability Plan must ~~include~~ list all OPERATING AUTHORITIES and entities to whom RELIABILITY COORDINATOR tasks have been delegated.

2.2. Requirements for certified operators. OPERATING AUTHORITIES and ~~E~~entities must also ensure that these tasks are carried out by NERC-certified system operators.

2.3. Auditing delegated tasks. Entities that accept delegation of ~~-~~Reliability Coordinator tasks, ~~will~~ may have these tasks audited under the NERC Reliability Coordinator audit program.

3. Reliability Coordinator ~~Entity~~ Reliability Plan~~organization certification~~. The Reliability Coordinator's ~~entity organization performing the Reliability Coordinator task must~~ Reliability Plan must be approved~~certified~~ by the NERC Operating Committee~~, , and that certification ratified by the Board of Trustees.~~

4. Wide Area View. The Reliability Coordinator shall monitor all bulk system facilities within its Reliability ~~Coordinator~~ Area and adjacent areas as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the Reliability Coordinator is able to determine ~~any relevant IROL's.~~ any potential Interconnected Reliability Limits within its Reliability Area.

(This responsibility may require Reliability Coordinators to receive sub-transmission information not normally monitored by their Energy Management System to assist in IRL determination.).

5. Determination of ~~Assessments of~~ IR~~O~~Ls.

5.1. ~~The basis for~~ The Reliability Coordinator shall determine IRLs ~~shall be based~~ on local, regional and interregional studies.

~~4.2.~~5.2. The Reliability Coordinator must be aware~~It should also be noted~~ that an IR~~O~~L can ~~become restrictive~~occur during multiple, normally non-critical outage conditions and as such, the Reliability Coordinator must ~~monitor~~ be knowledgeable of events that could lead to such an occurrence.

~~5.~~6. ~~Monitoring~~Situational Awareness. The Reliability Coordinator shall monitor its Reliability ~~Coordinator~~ Area, including the following parameters, to maintain "situational awareness," such as:

New section. List contributed by Dave McNeill.

- Current status of the Bulk Electric System within the Reliability Coordinator's Reliability Area
- Current projected post-contingency overloads (PPCO), the applicable mitigation plan for each identified PPCO, the viability and scope of each mitigation plan;
- Current projected post-contingency undervoltages (PPCU), the applicable mitigation plan for each identified PPCU, and the viability and scope of each mitigation plan;
- ~~Additional PPCO's and PPCU's expected to arise within the next 4 hours;~~
- System configuration changes planned for the next 24 hours;
- All generators within the subregion operating with AVR in a mode other than automatic voltage control;
- System reserve requirements;
- Current and expected reserves for next 4 hours;
- Current ACE for CA's within the subregion;
- Current TLR's in effect for constraints within the Subregion;
- Current local procedures in effect for constraints within the Subregion;
- Developing constraints within the Subregion;
- Planned native generation outages;
- Load zone import requirements and limits;
- EEA's in effect for the Entergy subregion or neighboring control areas;
- Status and criteria of all load-shed protection schemes.

~~6.~~7. Facility status. The Reliability Coordinator must know the status of all current and next day critical facilities whose failure, degradation or disconnection could result in an Interconnection Reliability Limit violation. Reliability Coordinators must also know the status of any facilities that may be required to assist area restoration objectives.

~~7.~~8. **Authority to act**. The Reliability Coordinator must have the authority to act and to direct actions to be taken by other OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA. These actions shall be taken within the NERC approved timelines listed in Policy 2.

~~8.~~9. **Serving the interests of Reliability Coordinator Area and Interconnection**. The RELIABILITY COORDINATOR must act in the interests of the reliability of the overall RELIABILITY ~~COORDINATOR~~ AREA and its INTERCONNECTION before any other entity (CONTROL AREA, PURCHASING-SELLING ENTITY, etc.).

~~9.~~10. **Coordination Agreements**. The RELIABILITY COORDINATOR must have clear, comprehensive coordination agreements with adjacent RELIABILITY COORDINATORS to mitigate transmission overloads or minimum voltage concerns ~~across~~ within its RELIABILITY ~~COORDINATOR~~ AREA ~~boundaries~~.

~~10.~~11. **TTC/ATC and transmission coordination**. The Reliability Coordinator must have the authority to direct OPERATING AUTHORITIES within the RELIABILITY ~~COORDINATOR~~ AREA to include known or expected transmission limitations within the RELIABILITY ~~COORDINATOR~~ AREA and other RELIABILITY COORDINATOR RELIABILITY AREAS in the determination of transfer capabilities. The ~~Src~~ Relia must direct that provision of transmission service be coordinated such that known or expected transmission limitations within its RELIABILITY ~~COORDINATOR~~ AREA and other RELIABILITY COORDINATOR RELIABILITY AREAS are respected, in accordance with filed tariffs and regional TTC/ATC calculation processes.

Should #11 be moved to Policy 6?

~~11.~~12. **Staff and facilities.** Must have adequate staff and facilities:

~~11.1.~~12.1. **Staffing and Training.** The RELIABILITY COORDINATOR must be staffed with ~~appropriately~~ adequately trained and NERC-Certified System Operators, 24 hours/day, seven days/week. The Reliability Coordinator ~~is expected to~~must have detailed knowledge of ~~their~~ its area~~s~~, ~~their~~ its facilities and associated Operating Authorities' processes including emergency procedures and restoration objectives. Minimum training for the RELIABILITY COORDINATOR~~s~~ shall meet or exceed a minimum of 5 days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel. ~~**[Reference Policy 8]**~~

The minimum training requirements shall be moved to Policy 8 upon its next revision.

~~11.2.~~12.2. **Adequate facilities.** Must have the facilities to perform their responsibilities, including:

~~11.2.1.~~12.2.1. **Communications.** ~~Appropriate~~ Adequate communications (voice ~~&~~and data links) such as priority communication paths to appropriate ~~entities which~~entities, which are staffed and available to act in addressing a real time emergency condition.

~~11.2.2.~~12.2.2. **Timely dissemination of information**. This includes multi directional capabilities between an Operating Authority and its Reliability Coordinator and also from a Reliability Coordinator to its neighboring Reliability Coordinator(s).

~~11.2.3.~~12.2.3. **Monitoring.** Detailed real-time monitoring capability of the RELIABILITY ~~COORDINATOR~~ AREA and sufficient monitoring capability of the surrounding RELIABILITY ~~COORDINATOR~~ AREAS to ensure that potential

Interconnection Reliability Limits (IR~~O~~L) violations are identified. Monitoring systems shall provide information that can be easily understood and interpreted by the Reliability Coordinator, giving ~~.~~ ~~P~~particular emphasis ~~should be given~~ to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure.

Reliability Coordinators are expected to monitor their bulk system elements (generators, transmission lines, busses, transformers, breakers etc) that affect or could potentially affect the Interconnection. This monitoring overview shall include both real and reactive power system flows, parameters and reserves, elements that are or could be critical to IR~~O~~L's and system restoration requirements.

12.2.4. Analysis tools. The Reliability Coordinator shall have adequate ~~A~~analysis tools such as State Estimation, Pre- and Post- Contingency analysis capabilities (thermal, stability and voltage) and wide~~-~~-area overview displays.

12.2.4.1. RELIABILITY COORDINATOR analysis tools must be under the control of the RELIABILITY COORDINATOR including approvals for planned maintenance. Procedures shall be in place to mitigate the affects of analysis tool outages.

~~11.2.5.~~12.2.5. **Knowledge of** RELIABILITY ~~COORDINATOR~~ AREA**.** The Reliability Coordinator shall have a comprehensive understanding of its RELIABILITY ~~COORDINATOR~~ AREA and interaction with neighboring RELIABILITY COORDINATOR RELIABILITY AREAS. Although individual entities such as Transmission and Generator Operators have the ~~expert~~ most detailed knowledge of their particular systems, ~~it is expected that~~ Reliability Coordinators~~s~~ must ~~will~~ have an extensive understanding of the Operating Authorities within its area, such as, ~~including but not limited to~~ staff, operating practices and procedures ~~philosophies~~, restoration priorities and objectives, outage plans, equipment capabilities and restrictions. The Reliability Coordinator shall place ~~P~~particular attention ~~shall be placed~~ on IR~~O~~Ls and intertie ~~facilities~~facility limits. The RELIABILITY COORDINATOR shall ensure ~~proper~~ protocols are in place to allow the RELIABILITY COORDINATOR to have the best available information at all times.

~~11.3.~~12.3. **Continuous monitoring of Reliability Coordinator Area.** The Reliability Coordinator shall continuously monitor its RELIABILITY COORDINATOR AREA. This includes the provisions for backup facilities that shall be exercised if the main monitoring system is unavailable

~~**12.Independence.** The Reliability Coordinator shall be independent of the merchant function and must not pass on information or data to any wholesale merchant function (either internal or external) that is not made available simultaneously to all such wholesale merchant functions.~~

Suggest removing Section 12. It's covered much better in the Standards of Conduct document required in Section 13.

13. Standards of Conduct. The Reliability Coordinator shall sign and adhere to the NERC Reliability Coordinator Standards of Conduct. [Found in the front section of the Operating Manual.]

Suggested Organization for Section A. May be able to combine A and B into a single section. This outline has more detail than needed for this rewrite. Sam Jones and I are considering this for the RA Plan "template."

1. Responsibilities

- **1.1.** Responsibilities – Tasks
  - **1.1.1.** Operations Planning
    - **1.1.1.1.** Next-day studies
    - **1.1.1.2.** Generation plan review
    - **1.1.1.3.** Maintenance review (Transmission and Generation)
  - **1.1.2.** Monitoring
    - **1.1.2.1.** Wide area view
    - **1.1.2.2.** Transaction approvals
    - **1.1.2.3.** Transmission parameters
    - **1.1.2.4.** Frequency and balancing
    - **1.1.2.5.** Operating reserves (Interconnected Operations Services)
    - **1.1.2.6.** IROL calculation
      - 1.1..2..6.1. State Estimator and Contingency Analysis
      - 1.1..2..6.2. Nomograms
  - **1.1.3.** Emergency Operations
    - **1.1.3.1.** Directing emergency procedures
    - **1.1.3.2.** Mitigating IROL violations – using local and Interconnection procedures
  - **1.1.4.** Restoration
    - **1.1.4.1.** Restoration plan
    - **1.1.4.2.** Authority to direct restoration
- **1.2.** Responsibilities – Authorization
  - **1.2.1.** Authority to act directly
  - **1.2.2.** Authority to direct others to act
- **1.3.** Responsibilities – Delegation
  - **1.3.1.** To whom tasks are delegated
  - **1.3.2.** Assurance that responsibilities are not delegated

2. Coordination and Data Sharing

- **2.1.** With adjacent Reliability Authority Areas
  - **2.1.1.** Joint operating agreements (seams management)
  - **2.1.2.** Information sharing
  - **2.1.3.** ISN and SDX
- **2.2.** With other Reliability Authorities

2.2.1. RCIS, ~~WON,~~ et al

2.3. With other responsible entities

2.3.1. Balancing Authorities

2.3.2. Transmission Operator

2.3.3. Generator Operators

2.3.4. Transmission Service Providers

2.3.5. Interchange Authorities

3. Facilities

3.1. Communications

3.2. Study and analysis tools

3.2.1. State estimators and contingency analysis

4. Staff

4.1. Training

4.2. Certification

4.3. Code of conduct

4.4. Independence

B. Reliability Coordinator Tasks

Replace "Control Area" with "Operating Authority"?

The RELIABILITY COORDINATOR is responsible for the following tasks. Some of these tasks may be delegated to other OPERATING AUTHORITIES to perform on behalf of the RELIABILITY COORDINATOR. It should be noted that the responsibility given to the Reliability Coordinator rests with the Reliability Coordinator even if a task or a number of tasks has been delegated to another entity. Operating Authorities~~, so designated,~~ to whom the Reliability Coordinator has delegated certain tasks, must also ~~be independent of the merchant function and must~~ sign the Reliability Coordinator Standards of Conduct unless regulatory requirements specify otherwise.

1. Monitor the parameters that may have significant impacts within the RELIABILITY COORDINATOR'S RELIABILITY AREA and with neighboring RELIABILITY COORDINATOR RELIABILITY AREAS with respect to:

1.1. Pending interchange schedules to identify potential flow impacts. As constrained areas approach or exceed ~~reliability limits~~System Operating Limits or Interconnected Reliability Limits, the RELIABILITY COORDINATOR shall work with the CONTROL AREA operators to evaluate and assess any additional INTERCHANGE SCHEDULES that would have an adverse impact on the CONSTRAINT. If CONSTRAINTS cannot be avoided through proactive intervention, the RELIABILITY COORDINATOR shall initiate ~~the appropriate~~ control action or emergency procedure to relieve the constraint consistent with the NERC approved timelines in Policy 2. All resources, including load shedding shall be available to the Reliability Coordinator in addressing a reliability issue. .

1.2. Availability/shortage of operating reserves needed to maintain reliability. The RELIABILITY COORDINATOR will monitor Control Area parameters to ensure that the required amount of operating reserves are provided and available as required. If necessary, the RELIABILITY COORDINATOR shall direct ~~-~~the CONTROL AREAS in the RELIABILITY ~~COORDINATOR~~ AREA to arrange for assistance from neighboring areas (CONTROL AREAS, REGIONS, etc.). The Reliability Coordinator shall issue ENERGY EMERGENCY ALERTS as ~~appropriate~~needed.

1.3. Actual flows versus limits at key facilities (particularly inter-CONTROL AREA, inter-REGIONAL and inter-RELIABILITY COORDINATOR RELIABILITY AREA interfaces**)** The RELIABILITY COORDINATOR shall identify the cause of the CONSTRAINT and initiate the ~~appropriate~~ control action or emergency procedure to relieve the constraint consistent with the NERC approved timelines in Policy 2. All resources, including load shedding, shall be available to the Reliability Coordinator in addressing a reliability issue.

1.4. Time error correction and SMD notification. The RELIABILITY COORDINATOR will communicate start and end times for time error corrections to the CONTROL AREAS within ~~his~~ their RELIABILITY ~~COORDINATOR~~ AREA. The RELIABILITY COORDINATOR will ensure all CONTROL AREAS are aware of Solar-Magnetic Disturbance (SMD) forecast information and assist as needed in the development of any required response plans.

1.5. Security issues of other Regions. The RELIABILITY COORDINATOR will participate in NERC Hotline discussions, assist in the assessment of security of the Regions and the overall Interconnected system, and coordinate actions in anticipated or actual emergency situations. The RELIABILITY COORDINATOR will disseminate information within ~~his~~ its RELIABILITY ~~COORDINATOR~~ AREA.

1.6. System frequency and resolution of significant frequency errors, deviations, and real-time trends. The RELIABILITY COORDINATOR shall monitor system frequency and its CONTROL AREAS performance and direct any necessary rebalancing to mitigate a reliability concern. All resources, including firm load shedding, shall be utilized as directed by a Reliability Coordinator to relieve the emergent condition.

1.7. Sharing with other RELIABILITY COORDINATORS any information regarding potential, expected, or actual critical operating conditions that could negatively impact other RELIABILITY COORDINATOR RELIABILITY AREAS. The RELIABILITY COORDINATOR shall coordinate with other RELIABILITY COORDINATORS and CONTROL AREAS as needed to develop and implement ~~appropriate~~ action plans to mitigate negative impacts of potential, expected, or actual critical operating conditions. This would include coordination of pending generation and transmission maintenance outages in both the real time and next day security analysis timeframes.

1.8. Availability/shortage of Interconnected Operations Services required (in applicable RELIABILITY COORDINATOR RELIABILTY AREAS). As necessary, the RELIABILITY COORDINATOR shall ~~-~~assist the CONTROL AREAS in ~~his~~ its RELIABILITY ~~COORDINATOR~~ AREA in arranging for assistance from neighboring areas (CONTROL AREAS, Regions, etc.).

1.9. Individual CONTROL AREA or RELIABILITY COORDINATOR RELIABILITY AREA ACE (in applicable RELIABILITY ~~COORDINATOR~~ AREAS). The RELIABILITY COORDINATOR will identify sources of large ACE deviations that may be contributing to frequency, time error, or inadvertent problems and will discuss corrective action with the appropriate CONTROL AREA operator. If a frequency, time error, or inadvertent problem occurs outside of the RELIABILITY COORDINATOR'S RELIABILITY AREA, the RELIABILITY COORDINATOR will discuss on the NERC Hotline with other RELIABILITY COORDINATORS. Reliability Coordinators shall direct its Control Areas to rebalance their systems as indicated in section 1.6 above.

1.10. Use of Special Protection Systems (in applicable RELIABILITY COORDINATOR RELIAB ILITY AREAS). Whenever a Special Protection System that may have an inter-CONTROL AREA or inter-RELIABILITY COORDINATOR RELIABILITY AREA impact is armed, the RELIABILITY COORDINATORs shall be aware of the impact of the operation on inter-Area flows. The Reliability Coordinator shall be kept informed of the status of the SPS scheme including any degradation or potential failure to operate as expected.

1.11. Control and restoration of islanded areas. The RELIABILITY COORDINATOR will assist CONTROL AREA operators in controlling islanding. The RELIABILITY COORDINATOR will assist the CONTROL AREA operators in re-establishing normal system configuration as requested and coordinate communications as required. Reliability Coordinators shall approve, communicate and coordinate the reparalleling of major system islands or paralleling points that could potentially have an adverse impact on an adjacent entity.

2. Ensure that the RELIABILITY COORDINATOR staff adhere to the data confidentiality agreement

3. Assume the responsibility for the safe and ~~-~~reliable operation of the bulk interconnected transmission system in accordance with NERC, Regional, and sub-Regional practices.

4. Determine the data requirements to support the reliability ~~-~~coordination task and coordinate for the provision of such data.

5. **Provide, or arrange provisions for, data exchange to other RELIABILITY COORDINATORS via the Interregional Security Network.**

6. ~~-~~**Assess contingency situations.** The Reliability Coordinator shall ~~determine~~ identify Interconnection Reliability Operating Limits for real time and next day operations. These assessments include thermal, voltage and stability related issues. Assessments shall be made up to and including ~~in real time and for the operations planning horizon~~ next-day at the CONTROL AREA level with any identified problems reported to the RELIABILITY COORDINATOR. The RELIABILITY COORDINATOR is to ensure that CONTROL AREA, RELIABILITY ~~COORDINATOR~~ AREA, and regional boundaries are sufficiently modeled to capture problems crossing such boundaries.

7. **The RELIABILITY COORDINATOR will be aware ~~ensure~~ each CONTROL AREA has a restoration plan** in accordance with NERC and Regional requirements. During system restoration, the RELIABILITY COORDINATOR shall monitor restoration progress and coordinate any needed assistance. The RELIABILITY COORDINATOR will serve as the primary contact for disseminating information regarding restoration to neighboring RELIABILITY COORDINATORS and CONTROL AREAS not immediately involved in restoration. . Reliability Coordinators shall approve, communicate and coordinate the reparalleling of major system islands or paralleling points that could potentially have an adverse impact on an adjacent entity.

~~8.~~

~~9.~~8. **Provide other coordination services** as appropriate and as ~~appropriate and as~~ **requested** by the CONTROL AREAS within its RELIABILITY ~~COORDINATOR~~ AREA and neighboring RELIABILITY COORDINATORS. The RELIABILITY COORDINATOR shall confirm study results and determine the effects within its own and adjacent RELIABILITY ~~COORDINATOR~~ AREAS. This action includes discussing options to mitigate system constraints and taking actions as necessary as to always act in the best interests of the interconnections at all times